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INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT

We Protect Hoosiers and Our Environment.

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NOTICE OF 30-DAY PERIOD FOR PUBLIC COMMENT

Preliminary Findings Regarding a
Signficant Modification to a
Part 70 Operating Permit

for BP Products North America Inc., - Whiting Business Unit in Lake County

Significant Source Modification No.: 089-35708-00453
Significant Permit Modification No.: 089-35729-00453

The Indiana Department of Environmental Management (IDEM) has received an application from BP Products North America Inc., - Whiting Business Unit, located at 2815 Indianapolis Blvd., Whiting, IN 46394, for a significant modification of its Part 70 Operating Permit issued on December 8, 2014. If approved by IDEM's Office of Air Quality (OAQ), this proposed modification would allow BP Products North America Inc., - Whiting Business Unit to make certain changes at its existing source. BP Products North America Inc., - Whiting Business Unit has applied to incorporate requirements of the First Amendment to Consent Decree Civil No. 2:12-CV-207.

This draft Part 70 Operating Permit does not contain any new equipment that would emit air pollutants; however, some conditions from previously issued permits/approvals have been corrected, changed, or removed. These corrections, changes, and removals may include Title I changes (e.g., changes that add or modify synthetic minor emission limits). This notice fulfills the public notice procedures to which those conditions are subject. IDEM has reviewed this application and has developed preliminary findings, consisting of a draft permit and several supporting documents, which would allow for these changes.

A copy of the permit application and IDEM's preliminary findings are available at:

Whiting Public Library
1735 Oliver St.
Whiting, IN 46394

and

IDEM Northwest Regional Office
330 W. US Highway 30, Suites E & F
Valparaiso, IN 46385

A copy of the preliminary findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/.

How can you participate in this process?

The date that this notice is published in a newspaper marks the beginning of a 30-day public comment period. If the 30th day of the comment period falls on a day when IDEM offices are closed for business, all comments must be postmarked or delivered in person on the next business day that IDEM is open.

You may request that IDEM hold a public hearing about this draft permit. If adverse comments concerning the **air pollution impact** of this draft permit are received, with a request for a public hearing, IDEM will decide whether or not to hold a public hearing. IDEM could also decide to hold a public meeting instead of, or in addition to, a public hearing. If a public hearing or meeting is held, IDEM will make a separate announcement of the date, time, and location of that hearing or meeting. At a hearing, you would have an opportunity to submit written comments and make verbal comments. At a meeting, you would have an opportunity to submit written comments, ask questions, and discuss any air pollution concerns with IDEM staff.

Comments and supporting documentation, or a request for a public hearing should be sent in writing to IDEM at the address below. If you comment via e-mail, please include your full U.S. mailing address so that you can be added to IDEM's mailing list to receive notice of future action related to this permit. If you do not want to comment at this time, but would like to receive notice of future action related to this permit application, please contact IDEM at the address below. Please refer to permit number SSM 089-35708-00453 and SPM 089-35729-00453 in all correspondence.

Comments should be sent to:

Doug Logan
IDEM, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
(800) 451-6027, ask for extension 4-5328
Or dial directly: (317) 234-5328
Fax: (317) 232-6749 attn: Doug Logan
E-mail: dlogan@idem.IN.gov

All comments will be considered by IDEM when we make a decision to issue or deny the permit. Comments that are most likely to affect final permit decisions are those based on the rules and laws governing this permitting process (326 IAC 2), air quality issues, and technical issues. IDEM does not have legal authority to regulate zoning, odor, or noise. For such issues, please contact your local officials.

For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Permit Guide on the Internet at: http://www.in.gov/idem/5881.htm; and the Citizens' Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

What will happen after IDEM makes a decision?

Following the end of the public comment period, IDEM will issue a Notice of Decision stating whether the permit has been issued or denied. If the permit is issued, it may be different than the draft permit because of comments that were received during the public comment period. If comments are received during the public notice period, the final decision will include a document that summarizes the comments and IDEM's response to those comments. If you have submitted comments or have asked to be added to the mailing list, you will receive a Notice of the Decision. The notice will provide details on how you may appeal IDEM's decision, if you disagree with that decision. The final decision will also be available on the Internet at the address indicated above, at the local library indicated above, at the IDEM Regional Office indicated above, and the IDEM public file room on the 12th floor of the Indiana Government Center North, 100 N. Senate Avenue, Indianapolis, Indiana 46204-2251.

If you have any questions, please contact Doug Logan of my staff at the above address.

Jenny Acker, Section Chief
Permits Branch
Office of Air Quality

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Ms. Natalie Grimmer
BP Products North America, Inc. - Whiting Business Unit
1701 121st St.
Whiting, Indiana 46394

Re: 089-35729-00453
Significant Permit Modification to
Part 70 Renewal No.: T089-30396-00453

Dear Ms. Grimmer:

BP Products North America, Inc. - Whiting Business Unit was issued Part 70 Operating Permit Renewal No. T089-30396-00453 on December 8, 2014 for a stationary refinery and marketing terminal located at 2815 Indianapolis Blvd., Whiting, IN 46394. An application requesting changes to this permit was received on April 13, 2015. Pursuant to the provisions of 326 IAC 2-7-12, a Significant Permit Modification to this permit is hereby approved as described in the attached Technical Support Document.

Please find attached the entire Part 70 Operating Permit as modified, including the following new and/or revised attachment(s):

Attachment C.vii:	40 CFR 60, Subpart UU, Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture (revised)
Attachment C.xiii:	40 CFR 60, Subpart NNN, Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations (revised)
Attachment C.xvi:	40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (revised)
Attachment E.ii:	40 CFR 63, Subpart Y, National Emission Standards for Marine Tank Vessel Loading Operations (revised)
Attachment E.iii:	40 CFR 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries (revised)

The permit references the below listed attachment(s). Since these attachments have been provided in previously issued approvals for this source, IDEM OAQ has not included a copy of these attachments with this modification:

Attachment A:	Fugitive Dust Control Plan
Attachment B.i:	40 CFR 65, Subpart A, Consolidated Federal Air Rule General Provisions
Attachment B.ii:	40 CFR 65, Subpart D, Consolidated Federal Air Rule Process Vents
Attachment B.iii:	40 CFR 65, Subpart G, Consolidated Federal Air Rule Closed Vent Systems, Control Devices, and Routing to a Fuel Gas System or a Process
Attachment C.i:	40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
Attachment C.ii:	40 CFR 60, Subpart J, Standards of Performance for Petroleum Refineries
Attachment C.iii:	40 CFR 60, Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007
Attachment C.iv:	40 CFR 60, 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

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Attachment C.v:	40 CFR 60, 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
Attachment C.vi:	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
Attachment C.viii:	40 CFR 60, Subpart VV, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006
Attachment C.ix:	40 CFR 60, 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
Attachment C.x:	40 CFR 60, Subpart XX, Standards of Performance for Bulk Gasoline Terminals
Attachment C.xi:	40 CFR 60, Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006
Attachment C.xii:	40 CFR 60, Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006
Attachment C.xiv:	40 CFR 60, Subpart QQQ, Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems
Attachment C.xv:	40 CFR 60, Subpart RRR, Standards of Performance for Volatile Organic Compound Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes
Attachment D.i:	40 CFR 61, Subpart J, National Emission Standard for Equipment Leaks (Fugitive Emission Sources) of Benzene
Attachment D.ii:	40 CFR 61, Subpart V, National Emission Standard for Equipment Leaks (Fugitive Emission Sources
Attachment D.iii:	40 CFR 61, Subpart FF, National Emission Standard for Benzene Waste Operations
Attachment E.i:	40 CFR 63, Subpart R, National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)
Attachment E.iv:	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
Attachment E.v:	40 CFR 63, Subpart EEEE, National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline)
Attachment E.vi:	40 CFR 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
Attachment E.vii:	40 CFR 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters
Attachment E.viii:	40 CFR 63, Subpart GGGGG, National Emission Standards for Hazardous Air Pollutants: Site Remediation

Previously issued approvals for this source containing these attachments are available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/.

Federal rules under Title 40 of United States Code of Federal Regulations may also be found on the U.S. Government Printing Office's Electronic Code of Federal Regulations (eCFR) website, located on the Internet at: http://www.ecfr.gov/cgi-bin/text-idx?tpl=/ecfrbrowse/Title40/40tab_02.tpl.

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A copy of the permit is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/. For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Permit Guide on the Internet at: http://www.in.gov/idem/5881.htm; and the Citizens' Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

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 Doug Logan, of my staff, OAQ, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana, 46204-2251 at 317-234-5328 or 1-800-451-6027, and ask for extension 4-5328.

Sincerely,

Jenny Acker, Section Chief
Permits Branch
Office of Air Quality

Attachments: Modified Permit and Technical Support Document
cc: File - Lake County
Lake County Health Department
U.S. EPA, Region 5
Compliance and Enforcement Branch
IDEM Northwest Regional Office

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Part 70 Operating Permit Renewal

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 operate subject to the conditions contained herein, the source described in Section A (Source Summary) of this permit.

The Permittee must comply with all conditions of this permit. Noncompliance with any provisions of this permit is grounds for enforcement action; permit termination, revocation and reissuance, or modification; or denial of a permit renewal application. Noncompliance with any provision of this permit, except any provision specifically designated as not federally enforceable, constitutes a violation of the Clean Air Act. It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. An emergency does constitute an affirmative defense in an enforcement action provided the Permittee complies with the applicable requirements set forth in Section B, Emergency Provisions.

This permit is issued in accordance with 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.

Operation Permit No.: T089-30396-00453	
Issued by: Original Signed Jenny Acker, Section Chief Permits Branch, Office of Air Quality	Issuance Date: December 8, 2014 Effective Date: January 1, 2015 Expiration Date: January 1, 2020

Administrative Amendment No. 089-35450-00453, issued on February 19, 2015.

Significant Permit Modification No.: 089-35729-00453	
Issued by: Jenny Acker, Section Chief, Permits Branch Office of Air Quality	Issuance Date:

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). 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(14)][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
SIC Code:	2911 (Petroleum Refining)
County Location:	Lake
Source Location Status:	Nonattainment for 8-hr 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)]

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

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

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

(3) 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.

(b) The BP Whiting Refinery (BP) needs high pressure steam and high pressure hydrogen for its Whiting Refinery Modernization Project (WRMP). Praxair owns and operates a plant near the BP facility that produces low pressure hydrogen, carbon dioxide and low pressure steam (Plant A). Praxair's Plant A sells less than 50% of its current production to BP. In order to supply the high pressure hydrogen and high pressure steam needed for BP's WRMP, Praxair constructed a new plant (Plant B) near Plant A. IDEM, OAQ has examined whether Praxair's new Plant B will be part of the same major source as Praxair's Plant A, and whether one or both of the Praxair plants are part of the same major source as BP. The term "major source" is defined at 326 IAC 2-7-1(22). In order for two or more plants to be considered one major source, they must meet all three of the following criteria:

(1) the plants must be under common ownership or common control;

(2) the plants have the same two-digit SIC Code or one must serve as a support facility for another; and,

(3) the plants must be located on contiguous or adjacent properties.

The Two Praxair Plants

The first analysis will be of the relationship between the two Praxair plants. The Praxair plants are owned by Praxair. In 1996, IDEM adopted nonrule policy document (NPD) Air-005 to provide guidance for major source determinations. This nonrule policy states that if two plants are owned by the same entity, then common control exists. Since the two Praxair plants have the same owner, there is also common control and the first criterion of the definition of major source is met.

The SIC Code Manual, 1987, sets out how to determine the proper SIC Code for each type of business. The SIC Code is based on the source's primary activity or product. Although OSHA started using NAICS, the North American Industry Classification System, a 6-digit industry grouping system in 2003, Indiana's source definition rules still refer to the SIC Code Manual, 1987. OSHA keeps the Standard Industrial Classification Code Manual, 1987, available at http://www.osha.gov/pls/imis/sic_manual.html on the internet. The two Praxair plant have the same two-digit SIC code 28 for the major group Chemicals and Allied Products. The two plants therefore meet the second criterion of the definition.

The last criterion of the definition is whether the two plants are located on contiguous or adjacent properties. Praxair's Plant B is located approximately 75 yards from Praxair's Plant A. The plants are separated by property owned by Mittal Steel. A Mittal Steel bridge runs between the two Praxair properties. The two plants are not located on contiguous properties.

The term "adjacent" is not defined in Indiana's rules. NPD Air-005 adds the following guidance:

- properties that actually abut at any point would satisfy the requirement of contiguous or adjacent property.
- properties that are separated by a public road or public property would satisfy this requirement, absent special circumstances.
- other scenarios would be examined on an individual basis with the focus on the distance between the activities and the relationship between the activities.

All IDEM evaluations of adjacency are done on a case-by-case basis looking at the specific factors for the sources involved. The evaluation should look at whether the distance between the plants is sufficiently small that it enables them to operate as a single source. In addition to determining the distance between the sources, IDEM asks:

(1) Are materials routinely transferred between the plants?
(2) Do managers or other workers frequently shuttle back and forth to be involved actively in the plants?
(3) Is the production process itself split in any way between the plants?

These questions focus on whether the two separate sources are so interrelated that they are functioning as one plant, and whether the distance between them is small enough that it enables them to operate as one plant.

Praxair states that the site for Plant B was chosen because it was one of a very few possible sites in the area. Plant B must be located relatively close to BP to provide a cost effective way of supplying high pressure steam to BP's WRMP. Praxair has stated that it will not operate Plant B if the WRMP were to cease operation. Praxair has no customers for the additional 200 million cubic feet per day of high pressure hydrogen production or for the high pressure steam.

Materials will not be routinely transferred between the two Praxair sites. The only thing that will be transferred is low pressure steam produced at Plant A that is used as building heat for Plant B. Some of Plant B's piping will travel on Plant A's property but will not be directly connected to any process in Plant A.

The plant manager is the same for both the existing and new plant. Praxair uses the same plant manager for other Praxair sources that are in the same general area, even when the sources are miles apart. Praxair will employ additional regional employees with offices at Plant B that will have responsibilities at Plant A, Plant B and two other regional Praxair plants in Michigan. Praxair hired additional employees to operate Plant B. All Praxair employees located at Plant A and Plant B are cross-trained to perform tasks at either plant and all personnel are shared between the two plants. All employees at Plant A and Plant B may also be temporarily assigned to other Praxair plants in the region and elsewhere. Praxair uses this type of employee sharing companywide and would have used the same sharing arrangement even if Plant B had been located even further from Plant A.

Plant B will have its own control room, supply room, parts room and will function as a stand-alone plant. The production process will not be split in any way between the two Praxair plants. The raw materials Plant B will use to produce hydrogen and high pressure steam, natural gas, refinery gas and water, will come directly from BP.

The two Praxair plants do not operate as a single source. Though the plants will share one manager and production employees, they have separate and unrelated production processes. The plants could have the same relationship even if they were located many miles apart. Therefore, the two plants are not located on adjacent properties. Since they do not meet the third criteria of the major source definition, IDEM, OAQ finds that the two Praxair plants are not part of the same major source.

The Praxair Plants and the BP Whiting Refinery

IDEM, OAQ has also examined whether Praxair's Plant A and/or its new Plant B will be part of the same major source as BP. The same major source definition applies.

The Praxair plants have a different owner than BP and there is no other common owner. Where there is no common ownership, IDEM's NPD Air-005 sets out two tests to determine if common control exists. These are the two-pronged test and the but/for test. If either test is satisfied, then common control exists.

The two-pronged test examines if one of the sources is an auxiliary activity that directly serves the purpose of a primary activity and if the owner or operator of the primary activity has a major role in the day-to-day operations of the auxiliary activity. An auxiliary activity directly serves the purpose of a primary activity by supplying a necessary raw material to the primary activity or performing an integral part of the production process for the primary activity.

Day-to-day control of the auxiliary activity by the primary activity may be evidenced by several factors, including:

- is a majority of the output of the auxiliary activity provided to the primary activity?
- can the auxiliary activity contract to provide its products/services to a third-party without the consent of the primary activity?
- can the primary activity assume control of the auxiliary activity under certain circumstances?
- is the auxiliary activity required to provide periodic reports to the primary activity?

If one or a combination of these questions is answered affirmatively, common control may exist.

Plant A supplies hydrogen gas to BP. Plant A also produces hydrogen and carbon dioxide gases, which are sold to customers other than BP. More than 50% of Plant A’s sales are to its other customers. BP does not have a major role in the day-to-day operations of Plant A. Plant A and BP do not meet the first common control test

Plant B will dedicate 92.5 percent of its total output of high pressure hydrogen and high pressure steam to BP. Plant B does not yet have any other customers. In addition, BP will supply all of the natural gas, refinery gas and water used by Plant B. BP will have a major role in the day-to-day operations of Plant B. Plant B and BP meet the first common control test.

The second common control test, the but/for test, asks if the auxiliary activity would exist absent the needs of the primary activity. If all or a majority of the output of the auxiliary activity is consumed by the primary activity the but/for test is satisfied.

If BP were to close, Plant A would be able to continue operating, since it will still have most of its customers and it does not get any material from BP. The but/for test is not satisfied. Therefore, there is no common control between Plant A and BP.

Plant B would lose at least 92.5% of its sales and lose its supply of essential raw materials if BP were to close. Plant B would not be able to operate until it created new fuel and water supply lines. Plant B would also have to find new customers. Plant B and BP satisfy the but/for test. Therefore, there is common control between Plant B and BP.

The second part of the definition of major source is whether the plants have the same two-digit SIC Code or if one serves as a support facility for the other. Plant A and Plant B have the two-digit SIC Code 28 for the major group Chemicals and Allied Products. BP has the two-digit SIC Code 29 for the major group Petroleum Refining and Related Industries.

A plant is considered a support facility if at least 50% of its total output is dedicated to the other plant. Plant A does not send 50% or more of its output to BP; therefore it is not a support facility. Plant B has dedicated at least 92.5% of its output to BP, so it is a support facility to BP. The second element of the definition is met for BP and Plant B, but not for BP and Plant A.

The last element of the definition is whether Plant A and/or Plant B are on contiguous or adjacent properties with BP. Plant A is on property that shares a common 40 foot long property line with

BP's property. Therefore, Plant A and BP are on contiguous properties, meeting the third element of the definition.

Plant B is located on property that is not contiguous with BP's property. The two properties are about 1,600 feet apart. IDEM, OAQ must determine if Plant B and BP will be "adjacent". As stated above, all evaluations of adjacency are done on a case-by-case basis looking at the specific factors for the source involved. In addition to determining the distance between the sources, IDEM asks:

(1) Are materials routinely transferred between the plants?

(2) Do managers or other workers frequently shuttle back and forth to be involved actively in the plants?

(3) Is the production process itself split in any way between the plants?

These questions focus on whether the two separate sources are so interrelated that they are functioning as one plant, and that the distance between them is small enough that it enables them to operate as one

Refinery gas, natural gas and water will flow through lines from BP to Plant B. Plant B will use that fuel and raw material to create high pressure steam and hydrogen which will be sent to BP by other dedicated pipelines. It is important that Plant B is located near to BP for effective transmission of high pressure steam.

No managers or production staff will travel back and forth between Plant B and BP to be actively involved in both plants. The production process will be split between Plant B and BP, as the hydrogen and high pressure steam provided by Plant B will result in the production of additional refinery gas which can be sent to Plant B from BP.

IDEM, OAQ finds that the distance between the two plants is sufficiently small and their production processes are so intertwined that it allows them to function as one source. Therefore, Plant B and BP are located on adjacent properties.

Plant A and BP do not meet all three elements of the major source definition. Therefore, Plant A and BP are not part of the same major source. Plant B and BP meet all three elements of the definition. IDEM, OAQ therefore finds that Plant B and BP are part of the same major source.

A.3 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)][326 IAC 2-7-5(14)]

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 WRMP: Ultra Low NO_X Burners
H-300	180	120-06	None

* Heaters H-1X and H-200 stacks have continuous emissions monitors (CEMS) for NO_X.

(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 and abandoned in place in 2013), at No. 11 A Pipe Still are part of a closed system as described below.

(3) One (1) vacuum hot well (D-300), constructed in 1995 at No. 11C Pipe Still are part of a closed system as described below.

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 process equipment, including pumps, compressors (K-4 and K-4A at No. 11A Pipe Still and K-300A and K-300B at the No. 11C Pipe Still), pressure relief devices, sampling connection systems, open-ended lines, valves; and heat exchange 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 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) Cokers

(1) 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:

(A) 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

(B) 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'.

(C) 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.

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

(Note: The No. 11B Coker and existing Coke Handling System, heaters H-101, H-102, H-103, and H-104 will be replaced by the Coker 2 and new Coke Handling System and heaters F-201, F-202, and F-203 as part of the WRMP project, identified later in this Section).

(2) Coker 2, constructed as part of WRMP 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 Coker 2 heaters F-201, F-202, and F-203 are equipped with Selective Catalytic Reduction (SCR) for control of NO_X. The Coker 2 heater stacks have continuous emissions monitors (CEMS) for NO_X and CO. 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
F-201	208	800-01	Low-NO_X burners and selective catalytic reduction
F-202	208	800-02	Low-NO_X burners and selective catalytic reduction
F-203	208	800-03	Low-NO_X burners and selective catalytic reduction

(B) 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.

(C) The Coker 2 is connected to the South flare and associated flare gas recovery system FGRS1 (included in Section D.35). The system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(D) One (1) storage tank, identified as TK-6254, with a maximum storage capacity of 14,028,000 gallons storing coker resid at a vapor pressure less than 0.5 psia. Tank TK-6254 is equipped with a fixed roof and controlled by an iron sponge.

(E) Six (6) natural gas fired heaters, each rated at 1.0 mmBTU/hr, used for heating tank TK-6254.

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

(G) Miscellaneous process vent emissions, which are routed to the South Flare and associated flare gas recovery system FGRS1 (included in Section D.35).

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the WRMP 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 WRMP project. Also, as part of the WRMP Project, there will be upgrades made to the atmospheric and vacuum distillation towers and various heat exchangers and associated piping. 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-1CX	1977	410	130-04	Low NO_X burners
H-101A*	Permitted in 2008 (SPM 089-25488-00453)	355	130-05	Ultra low NO_X Burners

Heater Identification	Construction Date/Permitted Date	Maximum Heat Input Capacity (mmBTU/hr)	Stack Exhausted To	Emission Controls
H-101B*	Permitted in 2008 (SPM 089-25488-00453)	355	130-07	Ultra low NO_X Burners
H-102*	Permitted in 2008 (SPM 089-25488-00453)	331	130-06	Ultra low NO_X Burners

*Heaters H-101A, H-101B, and H-102 have continuous emissions monitors (CEMS) for NO_X and CO.

(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. D-7 was permanently decommissioned as part of the WRMP.

(3) The No. 12 Pipestill, after modifications, will be connected to the South flare and flare gas recovery system FGRS1 (included in Section D.35). The system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including compressors (K-1, K-1A, K-1B, K-101A, K-101B and K-101C), valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and flanges and heat exchange systems. Compressors K-1, K-1A, and K-1B will be shut down as part of WRMP.

(5) Miscellaneous process vent emissions, which are routed to the South Flare and associated flare gas recovery system FGRS1 (included in Section D.35).

(d) The Sulfur Recovery Plant (SRP), 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 WRMP Project, increasing the capacity to 1,300 long tons per day of sulfur. Additional sulfur capacity can be achieved with oxygen enrichment in the C, D and E Claus trains as part of the original WRMP design with no increase in permitted emissions. 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 tailgas 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 WRMP project.

(3) One (1) tailgas 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 WRMP 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 WRMP 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 WRMP project.

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

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

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

(9) Caustic soda storage tanks and sodium bisulfite storage tanks, and handling equipment, to be decommissioned as part of the WRMP 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 WRMP 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. As specified by the Federal Consent Decree from United States, et al. v BP Products North America Inc, Civil No. 2:12-CV-00207 (N.D. Ind. Hammond Div., May 23, 2012), the SRU Flare was permanently decommissioned on August 12, 2013 by the installation of a welded blind on the piping.

(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 WRMP project.

(13) Two (2) modular degassing units, to be installed as part of the WRMP 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 WRMP 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 WRMP project, the sulfur pits A, B and C will be decommissioned and replaced with sealed sulfur collection drums. These sulfur drums are vented to the SRU A/B/C tailgas lines which are routed to either TGU A and/or TGU B.

(15) Two (2) new SRU D and E sulfur trains, installed as part of the WRMP project, have two (2) sealed sulfur collection drums which will be used to store molten sulfur. These drums are vented to the SRU D/E tailgas lines, which are routed to either TGU A and/or TGU B.

(16) One (1) sour water storage tank, identified as TK-431, with a maximum storage capacity of 845,600 gallons and used to store material that has a vapor pressure of less than 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 TGU A and TGU B, to be installed as part of the WRMP project, thermal oxidation systems which combust natural gas, each rated at 72 mmBTU/hr, equipped with SO_2 and CO CEMS, and NOx CEMS approved in 2015 for installation, exhausting at stacks S/V 162-06 and 162-07.

(19) Two (2) sulfur storage tanks, identified as TK-315 and TK-316, 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 WRMP Project and are both fixed roof tanks controlled by a steam blanketed, water eductor system routed back to the process.

(20) One (1) sulfur loading operation to be installed as part of the WRMP Project.

(21) The Sulfur Recovery Plant, after installation of TGU A and TGU B, will be connected to the South flare and associated flare gas recovery system FGRS1 (included in Section D.35). The system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

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

(23) Miscellaneous process vent emissions, which are routed to the South Flare and associated flare gas recovery system FGRS1 (included in Section D.35).

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

<u>Main Operating Scenario Post-WRMP:</u>
The tailgases from the five trains are sent to both of the COTs.
<u>Alternate Operating Scenario #1 Post-WRMP:</u>
One of the COTs is not operated and the tailgases 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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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 instrumentation and heat exchange systems. As part of the WRMP Project, there will be upgrades made to various heat exchangers and associated piping and retraying of distillation towers at VRU 100 and VRU 200. 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 hydrocarbon pressure relief discharges that were previously routed to the VRU 100/200 vent stacks, are being re-routed to the VRU flare or associated flare gas recovery system FGRS3 (identified in Section D.35).

(f) (1) 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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, there will be upgrades made to various distillation towers, compressor K-340, and associated piping at VRU 300. Upon completion of WRMP, some portions of VRU 300 will be connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or 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:

(A) One (1) off-gas knock out drum (D-400), which exhausts to the VRU flare and associated flare gas recovery system FGRS3 (identified in Section D.35).

(B) 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 and heat exchange systems.

(2) Vapor Recovery Unit VRU 400 for the Coker 2, permitted in 2008, to be installed as part of the WRMP project. This unit is connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or 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 K-401), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation and heat exchange systems. The facility may also include insignificant activities listed in Section A.4 of this permit.

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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 the Alky flare and associated flare gas recovery system FGRS3 (identified in Section D.35).

(2) One (1) spent acid stripper drum (D-13), which exhausts to the Alky flare and associated flare gas recovery system FGRS3 (identified in Section D.35).

(3) One (1) spent caustic drum (D-32), which exhausts to the Alky flare and associated flare gas recovery system FGRS3 (identified in Section D.35).

(4) One (1) spent acid storage tank (Tank 2), constructed in 1960, with a maximum storage capacity of 70,497 gallons, equipped with a fixed roof and controlled by carbon canisters.

(5) 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 and heat exchange systems.

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control 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 the Alky Flare or FGRS3 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 and heat exchange systems. 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 the UIU Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the MSAT II Compliance project approved in 2011 for construction, one (1) new C-250 Naphtha Splitter, a benzene saturation reactor system, and associated equipment (collectively identified as the Naphtha Splitter Unit) will be installed in the ISOM. 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, rated at 190 mmBTU/hr and vented to stack S/V 210-01.

(2) One (1) Flare Knock-out Drum (ISOM D-18), which exhausts to the UIU flare and associated flare gas recovery system FGRS4 (identified in Section D.35).

(3) Leaks from process equipment, including one (1) compressor (identified as K-1), pumps, valves, process drains and pressure relief devices and heat exchange systems.

(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 and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

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

(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. The BOU is connected to the 4UF Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP 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 WRMP, which vents to stack ID S/V250-01. The furnace is rated at 35 million Btu per hour 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 and heat exchange 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. The No. 2 Treatment Plant was permanently decommissioned as of December 30, 2008.

(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 was permanently decommissioned as of June 17, 2010.

(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). The loading facilities have been isolated from refinery operations and permanently decommissioned.

(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, including pumps, compressors, pressure relief devices, sampling connections systems, open-ended line or valves, flanges and other connectors.

(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 C-2 Splitter Tower will be shut down and permanently decommissioned as part of the MSAT II Compliance project, approved in 2011 for construction. The unit now consists of the C2 D-18 flare gas separator, the D-24 knock-out drum and associated piping.

The No. 3 Ultraformer is connected to the UIU flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or 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 (C2 D-18) with emissions vented to vessel D-24, which exhausts to the UIU flare and associated flare gas recovery system FGRS4 (identified in Section D.35).

(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 and heat exchange 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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. 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 / Ultra Low NOx Burners on and after December 31, 2016
F-3*	242	224-03	None / Ultra Low NOx Burners on and after December 31, 2016
F-4	137	224-04	None
F-5	99	224-04	None
F-6	49	224-04	None
F-7	52	224-05	None

*On and after December 31, 2016, heaters F-2 and F-3 stacks have continuous emissions monitors (CEMS) for NOx.

(2) The No. 4 Ultraformer is connected to the 4UF flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or 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 and heat exchange 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.

(6) One (1) gas conditioning system, approved in 2013 for construction, consisting of drums, coolers, piping, pumps, and sewer components.

(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) The HU is connected to the DDU Flare (identified in Section D.35). This system flare is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns and depressuring equipment for maintenance.

(3) One (1) CO2 vent from the HU process. This vent has the potential to emit small amounts of methanol.

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

(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 B-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 B-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, including pumps, compressors, pressure relief devices, sampling connections systems, open-ended line or valves, flanges and other connectors and heat exchange systems.

(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 CFHU is connected to the No. 4 Ultraformer flare stack. The No. 4 Ultraformer Flare Stack, S/V 2224-06, is used to control VOC emissions during emergency situations, 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, including pumps, compressors, pressure relief devices, sampling connections systems, open-ended line or valves, flanges and other connectors and heat exchange systems.

(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 and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or 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 and heat exchange systems.

(4) Miscellaneous process vent emissions, which are routed to the UIU flare and associated flare gas recovery system FGRS4 (identified in Section D.35).

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. Stack S/V 230-01 has continuous emissions monitors (CEMS) for NO_X, SO_2, CO and O_2.

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

(3) FCU 500 is connected to the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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).

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

(6) 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 a flare or flare gas recovery system.

(7) 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 WRMP project related contemporaneous emissions increases.

(8) Miscellaneous process vent emissions, which are routed to the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35).

(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. Stack S/V has continuous emissions monitors (CEMS) for NO_X, SO_2, CO and $O_{2.}$

(2) Two catalyst storage bins, one each for equilibrium and fresh catalyst, controlled by one (1) baghouse. (Spent catalyst is stored in Bin F-52, which is associated with FCU 500.)

(3) FCU 600 is connected to the FCU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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-3D and J-3E).

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

(6) 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 a flare or flare gas recovery system.

(7) 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 WRMP project related contemporaneous 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 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 Consent Decree 2:96 CV 095 RL.

The No. 1 SPS Boilers 5, 6, and 7 were shut down as of April 1, 2010.

(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 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
#31 Boiler	1948	575	503-01	(pre SPM 089-25488-00453) low- NO_X burners, an induced flue gas recirculation (IFGR) system, and an over fired air (OFA) system
#32 Boiler	1948	575	503-02	Per SPM 089-25488-00453 : The low- NO_X burners, IFGR and OFA will be replaced by conventional burners and a Selective Catalytic Reduction (SCR) system on Boilers # 31, 32, 33, 34, 36
#33 Boiler	1951	575	503-03	
#34 Boiler	1951	575	503-04	
#36 Boiler	1953	575	503-05	

* Boiler #31, #32, #33, #34, and #36 stacks have continuous emissions monitors (CEMS) for NOx and CO.

(2) Five (5) direct-fired duct burners, permitted in 2008 (SPM 089-25488-00453), rated at 41 mmBTU/hr each, equipped with low NO_X burners and controlled by a Selective Catalytic Reduction (SCR) system. The duct burner stacks have continuous emissions monitors (CEMS) for NOx and CO.

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

(y) Hazardous Waste Treatment System:

(1) Dewatering system for processing sludge, per SSM 089-25484-00453, issued May 1, 2008, 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. The feed rate capacity at the DAF/API dewatering system is 60,000 gallons per day. This facility includes the following emission sources and may 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;

(E) One (1) vapor recovery system on the dewatering system including a wet scrubber and carbon canister system.

(2) One (1) dewatering system, identified as the DNF dewatering system, approved in 2014 for construction, equipped with multiple frac tanks, electric boilers, centrifuges, and a wet scrubber, will be installed as part of the Lakefront Upgrades Project to process float and sludge from the Dissolved Nitrogen Floatation (DNF) System. The feed rate capacity will be 505,000 gallons per day. Vapors from the system will be routed to dual carbon canisters.

(3) One (1) Tank Cleaning Dewatering System, approved in 2014 for construction, equipped with multiple frac tanks, electric boilers, centrifuges, and a wet scrubber for processing sludge during routine cleaning of TK-5050, TK-5051, and TK-5052. The feed rate capacity will be 240,000 gallons per day. Vapors from the system will be routed to dual carbon canisters.

(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. As part of the Lakefront Upgrades (LFU) Project, approved in 2014 for modification, the larger solids in the wastewater will be removed in the new Solids Collection System. Then the wastewater will be routed to tanks TK-5050, TK-5051 and TK-5052, which will operate in parallel and serve as oil-water separators, equalization, and stormwater surge. Floating oil will be separated and skimmed from the tanks and recycled. The water will be routed to the new Dissolved Nitrogen Floatation (DNF) Units to remove suspended solids and oil, which will be 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 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, solids tank TK-562, which will vent to carbon canisters by no later than the startup of the new Dissolved Nitrogen Floatation (DNF) System, installed as a part of the Lakefront Upgrades Project; and Dissolved 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 TK-5051 to DAF), DAF Flash Mixer, DAF Influent Channel, DAF Effluent Channel, DAF Primary Boxes, and DAF Sump.

(3) One (1) oil-water separation, equalization, and stormwater surge tank (identified as Tank TK-5051) having a maximum storage capacity of 10,000,000 gallons, constructed in 1988 and equipped with an external floating roof.

(4) One (1) oil-water separation, equalization, and stormwater surge tank (identified as Tank TK-5050) having a maximum storage capacity of 10,000,000 gallons, constructed in 1988. As part of the Lakefront Upgrades Project, TK-5050 will be equipped with an external floating roof, constructed in 2014.

(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) oil-water separation, equalization, and stormwater surge tank (identified as Tank TK-5052) having a maximum storage capacity of 11,676,000 gallons, constructed as part of the WRMP Project. This tank is equipped with an external floating roof.

(7) A brine treatment system with four (4) fixed roof tanks equipped with an iron sponge, constructed as part of WRMP project, identified as:

(A) TK-101, with a storage capacity of 128,972 gallons;
(B) TK-102, with a storage capacity of 128,972 gallons;
(C) TK-103, with a storage capacity of 128,972 gallons; and
(D) TK-104, with a storage capacity of 51,580 gallons.

(8) A Dissolved Nitrogen Floatation (DNF) system, which vents to a dual carbon canister system, approved in 2014 for construction, as part of the Lakefront Upgrades Project, identified as:

(A) Four (4) parallel units, T-310, T-320, T-330, and T-340, with a maximum annual flow of 9,855 million gallons per year; and

(B) Two (2) fixed-cover float and sludge handling tanks, TK-303 and TK-304, with a storage capacity of 12,666 gallons each.

(9) One (1) Solids Collection System, which consists of the J-92 pump lift station and strainer backwash system, with a storage capacity of 5,257 gallons, constructed as part of the Lakefront Upgrades Project.

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

(11) Sewer components associated with the Lakefront Upgrades Project.

(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) One (1) internal floating roof storage tank identified as 3727, storing either petroleum hydrocarbon with vapor pressure less than 0.5 psia or ethanol, constructed in 1948, with a maximum storage capacity of 857,717 gallons.

(3) 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
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

(4) Sixty-six (66) 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
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
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

(5) 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
TK-0563	WWTP	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-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	2014*	3,357,627	<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	2014*	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

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity (gallons)	Vapor Pressure of Liquid (psia)
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-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-2279	MARINE DOCK	LCCO/DCO Line Wash	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	--	--	--
3490		--	1925	3,373,413	<0.5
3495		--	1992	3,876,768	<0.5

"--" - no data provided.

*These units were permitted for construction in 2014. The exact construction years will be added after construction is complete.

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

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

(8) Two (2) Off-spec Brine Tanks, constructed as part of WRMP project, with internal floating roofs, identified as:

(A) TK-3559, with a storage capacity of 451,214 gallons
(B) TK-3560 with a storage capacity of 1,015,231 gallons

(9) As part of the WRMP project, BP is repurposing two existing tanks (TK-3911 and TK-3728 or an equivalent tank) to store diluent and two existing tanks (TK-3716 and TK-3475) to store heavy virgin naphtha.

(10) Fugitive components constructed as part of the Gas Oil Tanks Replacement Project, permitted in 2014.

(bb) The general facility remediation system, identified as Unit 999. Remediation includes multiple well point systems. The well point systems extract groundwater which may have a small hydrocarbon fraction. 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-137	1992	999-02	Vented Separately	Uncontrolled
J-138	1991 Extension 1994	999-03	J-138 and J-140 are vented with D-138 (vapor/liquid separation tank)	0.685 mmBTU per hour Thermal Oxidizer ITF
J-140	1981	999-05		
J-141	1988 Extension 1993	999-06	Vented Separately	Uncontrolled
J-156	1968-1970	999-07	Vented with J-157	Uncontrolled
J-157	1968-1970	999-08	Vented with J-156	Uncontrolled
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) Electric 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 WRMP 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 WRMP Project. Contemporaneous to the WRMP Project the other modules will be controlled with high efficiency drift eliminators.

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

Cooling Tower	Recirculation Rate/Make-up rate (gallons/minute)	Control Devices
Cooling Tower 7	22,000/982	high efficiency liquid drift eliminators
Cooling Tower 8	90,000/2956	high efficiency liquid drift eliminators

(4) Existing Cooling Towers affected by the WRMP project:

Cooling Tower	Recirculation Rate/Make-up rate (gallons/minute)	Control Devices
Cooling Tower 5	41,250/814	high efficiency liquid drift eliminators

(5) Associated heavy liquid pumps, heavy liquid valves, and heavy liquid pressure relief devices.

(6) One (1) modular back-up cooling tower system, identified as Modular Cooling Tower System, approved in 2014 for installation, to be brought onsite in the event that an existing cooling tower is out of service or operating at reduced rates for maintenance, repair, or replacement, with a maximum recirculation rate of 90,000 gallons per minute, with a maximum make-up rate of 3,000 gallons per minute, using high efficiency liquid drift eliminators as particulate control. This unit can stand in for Cooling Towers 1 through 8.

(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 one (1) process heater:

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

(2) The following two (2) 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
569	5,544,000	1981
3613	8,866,200	1992

(3) The following six (6) 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
3571	5,040,000	1971
3572	5,040,000	1971
3609	5,649,000	1973
3611	8,513,400	1973
6126	3,108,000	1999
6127	3,108,000	2000

(4) The following five (5) 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-3614	Residual Oil and/or Asphalt	2007	14,154,000	141,120,000	biofilter
TK-3615	Residual Oil and/or Asphalt	2007	14,154,000	141,120,000	biofilter
TK-3616	Trim Gas Oil	2007	2,268,000	16,800,000	biofilter
TK-3617	Trim Gas Oil	2007	2,268,000	16,800,000	biofilter

Under 40 CFR 60, Subpart UU, storage tanks TK-3614 through TK-3617, are each considered an affected facility.

Under 40 CFR 63, Subpart CC, storage tanks TK-3573, TK-3614 through TK3617, 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 and heat exchange systems.

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.

(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 a contemporaneous project to the WRMP Project, gasoline loading at the Marine dock will cease. 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-2), constructed in 1968, permitted for modification in 2008 (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.

(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)	Flare Gas Recovery System ID	Pilot Fuel Type
4UF Flare***	224-06	1972	H = 200 ft, D = 2.5 ft.	ARU, CFU, BOU, 4UF	15,000	FGRS4**** (installed as part of the FGR Project)	Fuel Gas and Natural Gas
FCU flare***	230-02	1945	H = 200 ft. D = 2.0 ft.	FCU 600	5620	FGRS3**** (installed as part of the FGR Project)	Fuel Gas and Natural Gas
UIU Flare***	220-04	1958	H = 199.5 ft. D = 2.5 ft.	ISOM, 3UF, 2TP, CRU	7550	FGRS4**** (installed as part of the FGR Project)	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	FGRS3**** (installed as part of the FGR Project)	Fuel Gas and Natural Gas
Alky Flare***	140-01	1961	H = 199.5 ft D = 2.5 ft.	PCU, Alky	3920	FGRS3**** (installed as part of the FGR Project)	Fuel Gas and Natural Gas
SRU Flare*****	162-03	1971	H = 300 ft. D = 1.5 ft.	SRU	688	none	Fuel Gas and Natural Gas
DDU Flare	698-02	1993	H = 200 ft. D = 1.5 ft.	DDU, HU, Coker, DHT	6000	none	Fuel Gas and Natural Gas
LPG Flare	604-01	1986	H = 50 ft. D = 1.2 ft.	LPG storage vessels and loading facilities	30	none	LPG
PIB Flare**	2	1982	H = 250 ft. D = 3.0 ft.	RGP/PGP Loading Rack	540,000 lb/hr	none	Fuel Gas and Natural Gas
GOHT Flare***	802-03	Installed as Part of WRMP	H = 316 ft. D = 5 ft	GOHT	N/A	FGRS2 (installed as a part of WRMP)	Natural Gas
South Flare***	800-04	Installed as Part of WRMP	H = 350 ft. D = 6 ft	Coker 2, 12PS, Sulfur Recovery Complex, VRU 300, VRU 400	N/A	FGRS1 (installed as a part of WRMP)	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). This unit has been permanently decommissioned.
*** - Flares are equipped with a flare gas recovery system. Under normal operation the recovered gas streams will be utilized in the refinery fuel gas system.
**** - Note that FGRS3 and FGRS4 are cross connected via a tie-line, to maximize gas recovery and use of available compressor capacity as needed.
*****As specified by the Federal Consent Decree from *United States, et al. v BP Products North America Inc*, Civil No. 2:12-CV-00207 (N.D. Ind. Hammond Div., May 23, 2012), the SRU Flare was permanently decommissioned on August 12, 2013 by the installation of a welded blind on the piping.

Additionally, the following emission units are associated with the flare gas recovery systems: Associated valves, pumps, compressors (FGRS1: K-103A and K-103B; FGRS2: K-946A and K-946B; FGRS3: K-281, K-282, K-283, and K-284; FGRS4: K-291, K-292, and K-293), pressure relief devices, sampling connection systems, open ended lines or valves, flanges or other connectors, instrumentation, and sewer components.

(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 and heat exchange systems. 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 35 mmBTU per hour and constructed in May 2005. As part of the WRMP Project, DHT Unit Heater B-601 was permanently decommissioned and a 41.9 mmBTU per hour natural gas fired heater, identified as B-601A, was constructed. 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. The DHT Heater B-601 was permanently decommissioned as of July 7, 2010.

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

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

(mm) 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 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:

(1) 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 the wet scrubber/carbon canister system S-1.

(2) Two (2) enclosed centrifuges (identified as Centrifuge #1 and #2) with no process vents.

(3) 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.

(4) Six (6) portable rectangular storage tanks, including:

(A) 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 the wet scrubber/carbon canister system S-1.

(B) 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 the wet scrubber/carbon canister system S-1.

(C) 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 the wet scrubber/carbon canister system S-1.

(5) 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

(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 WRMP 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 (K-901A, K-901B, K-901C, and K-902), pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation and heat exchange systems.

(3) The GOHT Unit is connected to the GOHT Flare and associated flare gas recovery system FGRS2 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns.

(4) Miscellaneous process vent emissions, which are routed to the GOHT Flare and associated flare gas recovery system FGRS2 (identified in Section D.35).

(oo) The New Hydrogen Unit (New HU), identified as Unit ID 801, owned and operated by Praxair, Inc. and constructed as part of the WRMP 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 NO_X. The New HU heater stacks have continuous emissions monitors (CEMs) for NO_X 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

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

(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 HU is connected to the New 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 New HU Flare will be operated with a water seal or nitrogen purge. As such, there will be no purge gas emissions from the New HU Flare. The New HU Flare exhausts to S/V 801-03.

(4) Associated valves, pumps, compressors (C-9120 and C-9230), pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation systems.

(5) One (1) diesel-fueled emergency generator rated at 1,214 HP.

(6) HU steam vent.

A.4 Insignificant Activities [326 IAC 2-7-1(21)][326 IAC 2-7-4(c)][326 IAC 2-7-5(14)]

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 $PM/PM_{10}/PM_{2.5}$ 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].

(6) One (1) lime loading operation at the Main Water Treatment Plant, consisting of two (2) lime silos (Lime Storage Bin North – UT 207 and Lime Storage Bin South- UT 208), permitted in 2014, controlled by one (1) bin vent filter. [326 IAC 6.8-1-2(a)]

(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)(J)(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
F-300	9.9	Natural gas	none
F-400	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.

(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 not related to the WRMP project. [40 CFR 60, Subpart IIII][40 CFR 63, Subpart ZZZZ]

(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]:

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

(2) 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) Other activities associated with emergencies, including on-site fire training approved by the department and stationary fire pump engines not related to the WRMP project. [326 IAC 2-7-1(21)(G)(xxii)][40 CFR 60, Subpart IIII][40 CFR 63, Subpart ZZZZ]

(z) 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) Boiler No. 1 with a maximum design capacity of 2.0 mmBTU/hr heat input and is natural gas-fired only, constructed in 2006, venting to stack, S-1.

(2) Boiler No. 2 with a maximum design capacity of 2.0 mmBTU/hr heat input and is natural gas-fired only, constructed in 2006, venting to stack, S-2.

(3) Boiler No. 3 with a maximum design capacity of 2.0 MMBtu/hr heat input and is natural gas-fired only, constructed in 2006, venting to stack, S-3.

(4) Boiler No. 4 with a maximum design capacity of 2.0 mmBtu/hr heat input and is natural gas-fired only, constructed in 2006, venting to stack, S-4.

(5) Boiler No. 5 with a maximum design capacity of 2.0 mmBtu/hr heat input and is natural gas-fired only, constructed in 2006, venting to stack, S-5.

(6) Boiler No. 6 with a maximum design capacity of 2.0 mmBtu/hr heat input and is natural gas-fired only, constructed in 2006, venting to stack, S-6.

(aa) 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.

(bb) 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.

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

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

(ee) Three (3) emergency diesel-fired fire pump engines, identified as Firepump 1, 2 and 3, per SPM 089-25488-00453, one rated at 359 HP and two rated at 460 HP. [40 CFR 60, Subpart IIII][40 CFR 63, Subpart ZZZZ]

(ff) 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.

(gg) One (1) glycol dehydration unit (GDU) to remove water from the refinery fuel gas system to reduce corrosion, which is composed of a glycol contactor and a stripper. Natural gas is used as the stripping medium The unit consists of the following equipment: a small (approx. 1,500 gal) tank to deliver glycol to the system, a glycol system of approx. 8,000 gal in capacity, heat exchangers and a coalescer, coolers, condensers, a glycol contactor, a glycol regenerator with a reboiler and stripper, and filters (carbon and sock types).

(hh) One (1) cooling tower, identified as Cooling Tower 1, with a maximum capacity of 35,000 gpm. [40 CFR 63, Subpart CC]

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, T089-30396-00453, is issued for a fixed term of five (5) years from the issuance 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 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 condition 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.4 Enforceability [326 IAC 2-7-7][IC 13-17-12]

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, the United States Environmental Protection Agency (U.S. EPA) and by citizens in accordance with the Clean Air Act.

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, within a reasonable time, any information that IDEM, OAQ 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. Upon request, the Permittee shall also furnish to IDEM, OAQ 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) A certification required by this permit meets the requirements of 326 IAC 2-7-6(1) if:

(1) it contains a certification by a "responsible official" as defined by 326 IAC 2-7-1(35), and

(2) the certification states that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(b) The Permittee may use the attached Certification Form, or its equivalent 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(35).

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. All 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 and Enforcement 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, 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 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 may require to determine the compliance status of the source.

The submittal by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

B.10 Preventive Maintenance Plan [326 IAC 2-7-5(12)][326 IAC 1-6-3]

(a) A Preventive Maintenance Plan meets the requirements of 326 IAC 1-6-3 if it includes, at a minimum:

(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.

The Permittee shall implement the PMPs.

(b) The Permittee shall prepare and maintain Preventive Maintenance Plans (PMPs) no later than ninety (90) days after issuance of this permit or ninety (90) days after initial start-up, whichever is later, including the following information on each facility:

(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 and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61--53 IGCN 1003
Indianapolis, Indiana 46204-2251

The PMP extension notification does not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

The Permittee shall implement the PMPs.

(c) A copy of the PMPs shall be submitted to IDEM, OAQ upon request and within a reasonable time, and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its PMPs whenever lack of proper maintenance causes or is the primary contributor to an exceedance of any limitation on emissions. The PMPs and their submittal do not require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(d) 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 that 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, or 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;

Telephone Number: 1-800-451-6027 (ask for Office of Air Quality, Compliance and Enforcement Branch), or
Telephone Number: 317-233-0178 (ask for Office of Air Quality, Compliance and Enforcement Branch)
Facsimile Number: 317-233-6865

Northwest Regional Office phone: (219) 464-0233; fax: (219) 464-0553.

(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 and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61--53 IGCN 1003
Indianapolis, Indiana 46204-2251

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 must 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 a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(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 limitations on emissions. However, IDEM, OAQ may require that the Preventive Maintenance Plans required under 326 IAC 2-7-4-(c)(8) be revised in response to an emergency.

(f) Failure to notify IDEM, OAQ 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.

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 date of permit issuance, 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 this permit's issuance;

(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, OAQ, has issued the modification. [326 IAC 2-7-12(b)(8)]

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 T089-30396-00453 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 permit, all previous registrations and permits are superseded by this Part 70 operating permit.

B.14 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.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 Operating 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 a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(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 must 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 2-7-3][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(42). The renewal application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

Request for renewal shall be submitted to:

Indiana Department of Environmental Management
Permit Administration and Support Section, 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, pursuant to 326 IAC 2-7-4(a)(2)(D), 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
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61--53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(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 or notice 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) or (c) 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
Permit Administration and Support 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
Air and Radiation Division, Regulation Development Branch -
- Indiana (AR--18J)
77 West Jackson Boulevard
Chicago, Illinois 60604-3590

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 emission trades that are subject to 326 IAC 2-7-20(b)(1) and (c)(1). 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 in the notices specified in 326 IAC 2-7-20(b)(1) and (c)(1).

(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(37)) 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 a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(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).

(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 SO_2 or NO_x under 326 IAC 21 or 326 IAC 10-4.

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

A modification, construction, or reconstruction is governed by the requirements of 326 IAC 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, 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 must 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 must 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 must 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
Permit Administration and Support Section, Office of Air Quality
100 North Senate Avenue
MC 61--53 IGCN 1003
Indianapolis, Indiana 46204-2251

Any such application does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(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 within 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 the 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), to determine the appropriate permit fee.

B.24 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 5-1-1 (Applicability) and 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.

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

The Permittee shall not operate an incinerator except as provided in 326 IAC 4-2 or in this permit. The Permittee shall not operate a refuse incinerator or refuse burning equipment except as provided in 326 IAC 9-1-2 or in this permit.

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 Particulate Matter 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%).

(b) The average instantaneous opacity of fugitive particulate emissions from an unpaved road shall not exceed ten percent (10%).

(c) The opacity of fugitive particulate emissions from exposed areas shall not exceed ten percent (10 %) on a six (6) minute average.

(d) The opacity of fugitive particulate emissions from continuous transfer of material onto and out of storage piles shall not exceed ten percent (10%) on a three (3) minute average.

(e) The opacity of fugitive particulate emissions from storage piles shall not exceed ten percent (10%) on a six (6) minute average.

(f) 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.

(g) The opacity of fugitive particulate emissions from the inplant transportation of material by front end loaders and skip hoists shall not exceed ten percent (10%).

(h) Material processing facilities shall include the following:

(1) 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.

(2) The PM_{10} emissions from building vents shall not exceed twenty--two thousandths (0.022) grains per dry standard cubic foot and ten percent (10%) opacity.

(3) The PM_{10} stack emissions from a material processing facility shall not exceed twenty-two thousandths (0.022) grains per dry standard cubic foot and ten percent (10%) opacity.

(4) The opacity of fugitive particulate emissions from the material processing facilities, except a crusher at which a capture system is not used, shall not exceed ten percent (10%) opacity.

(5) The opacity of fugitive particulate emissions from a crusher at which a capture system is not used shall not exceed fifteen percent (15%).

(i) The opacity of particulate emissions from dust handling equipment shall not exceed ten percent (10%).

(j) Material transfer limits shall be as follows:

(1) The average instantaneous opacity of fugitive particulate emissions from batch transfer shall not exceed ten percent (10%).

(2) Where adequate wetting of the material for fugitive particulate emissions control is prohibitive to further processing or reuse of the material, the opacity shall not exceed ten percent (10%), three (3) minute average.

(k) 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.

The Permittee shall achieve these limits by controlling fugitive particulate matter emissions according to the attached Fugitive Dust Control Plan.

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. The provisions of 326 IAC 1-7-1(3), 326 IAC 1-7-2, 326 IAC 1-7-3(c) and (d), 326 IAC 1-7-4, and 326 IAC 1-7-5(a), (b), and (d) are not federally enforceable.

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

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 that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(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 14-10-1, 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 Licensed 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 Licensed Asbestos Inspector to

thoroughly inspect the affected portion of the facility for the presence of asbestos. The requirement to use an Indiana Licensed Asbestos inspector is not federally enforceable.

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

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

(a) For performance testing required by this permit, a test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management
Compliance and Enforcement Branch, 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 a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(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 a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

(c) Pursuant to 326 IAC 3-6-4(b), all test reports must be received by IDEM, OAQ not later than forty--five (45) days after the completion of the testing. An extension may be granted by IDEM, OAQ if the Permittee 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)][40 CFR 64][326 IAC 3-8]

(a) For new units:
Unless otherwise specified in the approval for the new emission unit(s), compliance monitoring for new emission units shall be implemented on and after the date of initial start-up.

(b) For existing units:
Unless otherwise specified in this permit, for all monitoring requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance, to begin such monitoring. If due to circumstances beyond the Permittee's control, any monitoring equipment required by this permit cannot be installed and operated no later than ninety (90) days after permit issuance, 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 and Enforcement Branch, Office of Air Quality
100 North Senate Avenue
MC 61--53 IGCN 1003
Indianapolis, Indiana 46204-2251

in writing, prior to the end of the initial ninety (90) 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 a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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.

(b) For monitoring required by CAM, at all times, the Permittee shall maintain the monitoring, including but not limited to, maintaining necessary parts for routine repairs of the monitoring equipment.

(c) For monitoring required by CAM, except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the Permittee shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. Data recorded during monitoring malfunctions, associated repairs, and required quality assurance or control activities shall not be used for purposes of this part, including data averages and calculations, or fulfilling a minimum data availability requirement, if applicable. The owner or operator shall use all the data collected during all other periods in assessing the operation of the control device and associated control system. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

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 3-5] [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) All continuous emission monitoring systems are subject to monitor system certification requirements pursuant to 326 IAC 3-5-3.

(c) 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.

(d) 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.

(e) 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.

(f) 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.

(g) 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.

(h) 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.

(i) 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.

(j) Whenever the SO_2 continuous emission monitoring system on the TGU A or TGU B 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 H2S and COS concentration in TGU absorber offgas to incinerator. These parametric monitoring readings shall be recorded at least once per day until the primary CEM or backup CEM is brought online.

(k) Whenever the CO continuous emission monitoring system on the TGU A or TGU B is malfunctioning or will be down for calibration, maintenance, or repairs for more than twenty-four (24) hours, the Permittee shall monitor and record stack percent oxygen and incinerator 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.

(l) Whenever the NOx continuous emission monitoring system on the TGU A or TGU B is malfunctioning or will be down for calibration, maintenance, or repairs for more than twenty four (24) hours, the Permittee shall monitor and record stack percent oxygen 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.

(m) Nothing in this permit shall excuse the Permittee from complying with the requirements to operate a continuous emission monitoring system pursuant to 326 IAC 3-5 or any applicable requirements.

C.13 Maintenance of Emission Monitoring Equipment [326 IAC 3-5][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 Continuous Compliance Plan [326 IAC 6.8-8-1][326 IAC 6.8-8-8]

(a) Pursuant to 326 IAC 326 IAC 6.8-8-1, the Permittee shall submit to IDEM and maintain at the source a copy of the Continuous Compliance Plan (CCP). The Permittee shall perform the inspections, monitoring and record keeping in accordance with the information in 326 IAC 6.8-8-5 through 326 IAC 6.8-8-7 or applicable procedures in the CCP.

(b) Pursuant to 326 IAC 6.8-8-8, the Permittee shall update the CCP, as needed, retain a copy of any changes and updates to the CCP at the source and make the updated CCP available for inspection by the department. The Permittee shall submit the updated CCP, if required to IDEM, OAQ within thirty (30) days of the update.

(c) Pursuant to 326 IAC 6.8-8, failure to submit a CCP, maintain all information required by the CCP at the source, or submit update to a CCP is a violation of 326 IAC 6.8-8.

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 be no less than twenty percent (20%) of full scale. The analog instrument shall be capable of measuring values outside of the normal range.

(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 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 maintain the most recently submitted written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) Upon direct notification by IDEM, OAQ 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 must comply with the applicable requirements of 40 CFR 68.

C.18 Response to Excursions or Exceedances [40 CFR 64][326 IAC 3-8][326 IAC 2-7-5][326 IAC 2-7-6]

(I) Upon detecting an excursion where a response step is required by the D Section or an exceedance of a limitation, not subject to CAM, in this permit:

(a) The Permittee shall take reasonable response steps to 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 excess emissions.

(b) The response shall include minimizing the period of any startup, shutdown or malfunction. The response may include, but is not limited to, the following:

(1) initial inspection and evaluation;

(2) recording that operations returned or are returning 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 normal or usual manner of operation.

(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; and/or

(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 record the reasonable response steps taken.

(II)

(a) CAM *Response to excursions or exceedances.*

(1) Upon detecting an excursion or exceedance, subject to CAM, the Permittee shall restore operation of the pollutant-specific emissions unit (including the 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. 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). Such actions may include initial inspection and evaluation, recording that operations returned to normal without operator action (such as through response by a computerized distribution control system), or 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.

(2) 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, monitoring results, review of operation and maintenance procedures and records, and

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

(b) If the Permittee identifies a failure to achieve compliance with an emission limitation, subject to CAM, or standard, subject to CAM, for which the approved monitoring did not provide an indication of an excursion or exceedance while providing valid data, or the results of compliance or performance testing document a need to modify the existing indicator ranges or designated conditions, the Permittee shall promptly notify the IDEM, OAQ and, if necessary, submit a proposed significant permit modification to this permit to address the necessary monitoring changes. Such a modification may include, but is not limited to, reestablishing indicator ranges or designated conditions, modifying the frequency of conducting monitoring and collecting data, or the monitoring of additional parameters.

(c) Based on the results of a determination made under paragraph (II)(a)(2) of this condition, the EPA or IDEM, OAQ may require the Permittee to develop and implement a QIP. The Permittee shall develop and implement a QIP if notified to in writing by the EPA or IDEM, OAQ.

(d) Elements of a QIP:
The Permittee shall maintain a written QIP, if required, and have it available for inspection. The plan shall conform to 40 CFR 64.8 b (2).

(e) If a QIP is required, the Permittee shall develop and implement a QIP as expeditiously as practicable and shall notify the IDEM, OAQ if the period for completing the improvements contained in the QIP exceeds 180 days from the date on which the need to implement the QIP was determined.

(f) Following implementation of a QIP, upon any subsequent determination pursuant to paragraph (II)(a)(2) of this condition the EPA or the IDEM, OAQ may require that the Permittee make reasonable changes to the QIP if the QIP is found to have:

(1) Failed to address the cause of the control device performance problems; or

(2) Failed to provide adequate procedures for correcting control device performance problems as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions.

(g) Implementation of a QIP shall not excuse the Permittee from compliance with any existing emission limitation or standard, or any existing monitoring, testing, reporting or recordkeeping requirement that may apply under federal, state, or local law, or any other applicable requirements under the Act.

(h) *CAM recordkeeping requirements.*

(1) The Permittee shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to paragraph (II)(a)(2) of this condition and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under this condition (such as data used to document the adequacy of monitoring, or records of monitoring maintenance or

corrective actions). Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

(2) Instead of paper records, the owner or operator may maintain records on alternative media, such as microfilm, computer files, magnetic tape disks, or microfiche, provided that the use of such alternative media allows for expeditious inspection and review, and does not conflict with other applicable recordkeeping requirements

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 submit a description of its response actions to IDEM, OAQ, no later than seventy-five (75) days after the date of the test.

(b) A retest to demonstrate compliance shall be performed no later than one hundred eighty (180) days after the date of the test. Should the Permittee demonstrate to IDEM, OAQ that retesting in one -hundred eighty (180) 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 a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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]

Pursuant to 326 IAC 2-6-3(a)(1), the Permittee shall submit by July 1 of each year an 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 purpose of fee assessment.

The statement must 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

The emission statement does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

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. Support information includes the following, where applicable:

(AA) All calibration and maintenance records.

(BB) All original strip chart recordings for continuous monitoring instrumentation.

(CC) Copies of all reports required by the Part 70 permit.

Records of required monitoring information include the following, where applicable:

(AA) The date, place, as defined in this permit, and time of sampling or measurements.

(BB) The dates analyses were performed.

(CC) The company or entity that performed the analyses.

(DD) The analytical techniques or methods used.

(EE) The results of such analyses.

(FF) The operating conditions as existing at the time of sampling or measurement.

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 makes a request for records to the Permittee, the Permittee shall furnish the records to the Commissioner within a reasonable time.

(b) Unless otherwise specified in this permit, for all record keeping requirements not already legally required, the Permittee shall be allowed up to ninety (90) days from the date of permit issuance or the date of initial start-up, whichever is later, to begin such record keeping.

(c) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A), 326 IAC 2-2-8 (b)(6)(B), 326 IAC 2-3-2 (l)(6)(A), and/or 326 IAC 2-3-2 (l)(6)(B)) that a “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a “major modification” (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Before beginning actual construction of the “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, 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(pp)(2)(A)(iii) and/or 326 IAC 2-3-1 (kk)(2)(A)(iii); and

(iv) An explanation for why the amount was excluded, and any netting calculations, if applicable.

(d) If there is a reasonable possibility (as defined in 326 IAC 2-2-8 (b)(6)(A) and/or 326 IAC 2-3-2 (l)(6)(A)) that a “project” (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) at an existing emissions unit, other than projects at a source with a Plantwide Applicability Limitation (PAL), which is not part of a “major modification” (as defined in 326 IAC 2-2-1(dd) and/or 326 IAC 2-3-1(y)) may result in significant emissions increase and the Permittee elects to utilize the “projected actual emissions” (as defined in 326 IAC 2-2-1(pp) and/or 326 IAC 2-3-1(kk)), the Permittee shall comply with following:

(1) Monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any existing emissions unit identified in (1)(B) above; and

(2) 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) 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 emissions 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][40 CFR 64][326 IAC 3-8]

(a) The Permittee shall submit the attached Quarterly Deviation and Compliance Monitoring Report or its equivalent. Proper notice submittal under Section B –Emergency Provisions satisfies the reporting requirements of this paragraph. Any deviation from permit requirements, the date(s) of each deviation, the cause of the deviation, and the response steps taken must be reported except that 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. This report shall be submitted not later than thirty (30) days after the end of the reporting period. The Quarterly Deviation and Compliance Monitoring Report shall include a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35). A deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit.

On and after the date by which the Permittee must use monitoring that meets the requirements of 40 CFR Part 64 and 326 IAC 3-8, the Permittee shall submit CAM reports to the IDEM, OAQ.

A report for monitoring under 40 CFR Part 64 and 326 IAC 3-8 shall include, at a minimum, the information required under paragraph (a) of this condition and the following information, as applicable:

(1) Summary information on the number, duration and cause (including unknown cause, if applicable) of excursions or exceedances, as applicable, and the corrective actions taken;

(2) Summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable); and

(3) A description of the actions taken to implement a QIP during the reporting period as specified in Section C-Response to Excursions or Exceedances. Upon completion of a QIP, the owner or operator shall include in the next summary report documentation that the implementation of the plan has been completed and reduced the likelihood of similar levels of excursions or exceedances occurring.

The Permittee may combine the Quarterly Deviation and Compliance Monitoring Report and a report pursuant to 40 CFR 64 and 326 IAC 3-8.

(b) The address for report submittal is:

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

(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 on or before the date it is due.

(d) 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.

(e) If the Permittee is required to comply with the recordkeeping provisions of (d) in Section C - General Record Keeping Requirements for any "project" (as defined in 326 IAC 2-2-1(oo) and/or 326 IAC 2-3-1(jj)) *at an existing emissions unit*, and the project meets the following criteria, then the Permittee shall submit a report to IDEM, OAQ:

(1) The annual emissions, in tons per year, from 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(ww) and/or 326 IAC 2-3-1(pp), 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).

(f) The report for project at an existing emissions *unit* shall be submitted no later than 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 (d)(1) and (2) 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) and/or 326 IAC 2-3-2(c)(3).

(4) Any other information that the Permittee wishes to include in this report such as an explanation as to why the emissions differ from the preconstruction projection.

Reports required in this part shall be submitted to:

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

(g) 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 applicable standards for recycling and emissions reduction.

C.24 Consent Decree (Civil No. 2:12-CV-00207) Requirements

(a) As specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the following definitions shall apply throughout the permit:

(1) “Date of Entry” shall mean the date on which Consent Decree (Civil No. 2:12-CV-00207) is entered by the United States District Court for the Northern District of Indiana.

(2) “Date of Lodging” shall mean the date Consent Decree (Civil No. 2:12-CV-00207) is lodged with the United States District Court for the Northern District of Indiana.

(3) “7-day rolling average” shall mean the average daily emission rate or concentration during the preceding 7 days. For purposes of clarity, the first day used in a 7-day rolling average compliance period is the first day on which the emission limit is effective, and the first complete 7-day average compliance period is 7 days later (e.g., for a limit effective on January 1, the first day in the period is January 1 and the first complete 7-day period is January 1 through January 7).

(4) “365-day rolling average” shall mean the average daily emission rate or concentration during the preceding 365 days. For purposes of clarity, the first day used in a 365-day rolling average compliance period is the first day on which the emission limit is effective, and the first complete 365-day average compliance period is 365 days later (e.g., for a limit effective on January 1, the first day in the period is January 1 and the first complete 365-day period is January 1 through December 31).

(5) “12-month rolling average” shall mean the sum of the average rate or concentration of the pollutant in question for the most recent complete calendar month and each of the previous 11 calendar months, divided by 12. A new 12-month rolling average shall be calculated for each new complete month. For purposes of clarity, the first month used in a 12-month rolling average

compliance period is the first full calendar month in which the emission limit is effective, and the first complete 12-month rolling average compliance period is 12 calendar months later (e.g., for a limit effective on December 31, the first month in the period is January and the first complete 12-month period is January through the following December).

(6) “Fuel Oil” shall mean any liquid fossil fuel with sulfur content of greater than 0.05% by weight.

SECTION D.0 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Source Wide 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.0.1 Completion of WRMP Definition

No later than 180 days from the start-up of the Coker 2 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 Whiting Refinery Modernization Project (WRMP). The WRMP was completed on May 10, 2014.

D.0.2 Petroleum Refineries (Process Trunaround) [326 IAC 8-4-2]

The owner or operator of a petroleum refinery shall notify the commissioner thirty (30) days prior to a process unit turnaround. In addition, the owner or operator shall minimize volatile organic compound emissions during turnaround, by providing for:

(a) depressurization venting of the process unit or vessel to a vapor recovery system, flare or firebox; and

(b) no emission of volatile organic compounds from a process unit or vessel until its internal pressure is 136 kPa (19.7 psi) or less.

Compliance Determination Requirements

D.0.3 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 WRMP project.

(b) 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 WRMP 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.0.4 Initial Testing Requirements for Existing Affected Emissions Units and 3SPS Boilers

(a) Not later than three (3) years after completion of the WRMP project, the Permittee shall perform the initial performance testing for NO_X, CO, PM, PM10, and VOC for no less than fifty percent (50%) of the emissions units listed in Table D.0.4. No later than five (5) years after the completion of the WRMP project, the Permittee shall perform the initial performance testing for NO_X, CO, PM, PM10 and VOC for the emissions units in Table D.0.4 not yet tested.

(b) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures) and utilizing methods approved by the commissioner. Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

Table D.0.4
Existing Affected Emissions Units & 3SPS Boilers Initial Performance Testing

Emission Unit	Pollutant			
	CO	PM/PM_{10}	VOC	NO_X
11A PS Heater H-1X	x	x	x	*
11A PS Heater H-2	x	x	x	x
11A PS Heater H-3	x	x	x	x
11C PS Heater H-300	x	x	x	x
ISOM H-1	x	x	x	x
ARU F-200A	x	x	x	x
ARU F-200B	x	x	x	x
4UF F-1	x	x	x	x
4UF F-2	x	x	x	*
4UF F-3	x	x	x	*
4UF F-4	x	x	x	x
4UF F-5	x	x	x	x
4UF F-6	x	x	x	x
4UF F-7	x	x	x	x
4UF F-8A	x	x	x	x
4UF F-8B	x	x	x	x
HU B-501	x	x	x	x
DDU B-301	x	x	x	x
DDU B-302	x	x	x	x
CFHU F-801A	x	x	x	x
CFHU F-801B	x	x	x	x
CFHU F-801C	x	x	x	x
CRU F-101	x	x	x	x
CRU F-102A	x	x	x	x
3SPS #31 Boiler	*	x	x	*
3SPS #32 Boiler	*	x	x	*
3SPS #33 Boiler	*	x	x	*
3SPS #34 Boiler	*	x	x	*
3SPS #36 Boiler	*	x	x	*
3SPS 5 Duct Burners	*	x	x	*

* Equipped with a CEMS for specified pollutant

SECTION D.1 EMISSIONS UNIT OPERATION CONDITIONS - No. 11 Pipe Still

Emissions Unit Description:

(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 WRMP: ***Ultra*** Low NO_X Burners
H-300	180	120-06	None

* Heaters H-1X and H-200 stacks have continuous emissions monitors (CEMS) for NO_X.

(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 and abandoned in place in 2013), at No. 11 A Pipe Still are part of a closed system as described below.

(3) One (1) vacuum hot well (D-300), constructed in 1995 at No. 11C Pipe Still are part of a closed system as described below.

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 process equipment, including pumps, compressors (K-4 and K-4A at No. 11A Pipe Still and K-300A and K-300B at the No. 11C Pipe Still), pressure relief devices, sampling connection systems, open-ended lines and valves, and heat exchange 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 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.

(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 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6 the Permittee shall comply with the following PM_{10} emission limitations for No. 11 pipe still (including nos. 11A and 11C pipe still) process heaters:

Process Heater	PM_{10} Limit (lbs/mmBTU)	PM_{10} 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.1.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and pursuant to Permit SSM 089-25484-00453 (issued May 1, 2008), upon startup of the ultra low- NO_X burners on heater H-200, the emissions of NO_X shall not exceed 0.05 pounds per million BTU of fuel gas fired.

(b) The Permittee shall comply with the following limits after completion of the WRMP project:

(1) Annual firing rate and SO_2 emissions limits:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	SO_2 emissions (tons per 12 consecutive month period)
H-200	1601.33	8.9
H-1X	1523.36	8.4
H-2	282.95	1.6
H-3	430.99	2.4

(2) Pursuant to SSM 089-32033-00453, H-300 shall comply with the following annual firing rate and SO_2 emission limits:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	SO_2 emissions (tons per 12 consecutive month period)
H-300	1,270.20	7.0

(3) CO, VOC, NO_X, and PM_{10} emissions limits:

Heater ID	CO lb/mmBTU)	VOC (lb/mmBTU)	NO_X (lb/mmBTU)	PM_{10} (lb/mmBTU)
H-1X	0.082	0.0054	0.166	0.0075
H-2	0.082	0.0054	0.098	0.0075
H-3	0.082	0.0054	0.098	0.0075
H-200	0.082	0.0054	0.05	0.0075
H-300	0.082	0.0054	0.137	0.0075

(4) Pursuant to SSM 089-32033-00453, H-1X, H-2, H-3, H-200, and H-300 shall comply with the following PM emission limits:

Heater ID	PM (lb/mmBTU)
H-1X	0.0075
H-2	0.0075
H-3	0.0075
H-200	0.0075
H-300	0.0075

(c) After the completion of the WRMP project, 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) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.1.6. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 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 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the ”Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207, Heaters H-1X, H-2, H-3, H-200 and H-300 shall be affected facilities for

SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas and combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for Heaters H-1X, H-2, H-3, H-200 and H-300.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than December 31, 2013, Heater H-200 shall be an affected facility for NO_X as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja for NO_X emissions for process heaters by the date specified in 40 CFR 60, Subpart Ja. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for Heater H-200.

D.1.5 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the No. 11A and 11C Pipe Stills are affected facilities pursuant to 40 CFR 60, Subpart GGGa upon the “Date of Entry” of the Consent Decree entered in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Section F.9 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the No. 11A and 11C Pipe Stills no later than one year from the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The No. 11A and 11C Pipe Stills shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.1.6 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:

(1) 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 Operating Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and 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 Heaters H-1X, H-2, H-3, H-200 and H-300.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to demonstrate compliance with Condition D.1.2, following the installation of the Ultra low- NO_X burners on the Heater H-200, the Heater H-200 shall operate using only Ultra low- NO_X burners.

(c) Pursuant to Permit SSM 089-25484-00453, issued May 1, 2008, and in order to demonstrate compliance with Condition D.1.2, after the completion of the WRMP project, the pressure relief discharges that were 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.1.8 Consent Decree (Civil No. 2:12-CV-00207) Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than December 31, 2013, the Permittee shall install, maintain, and continuously operate Ultra-Low NO_X burners on Heater H-1X.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than December 31, 2013, the emissions of NO_X from Heater H-1X shall not exceed 0.06 lb/mmBTU based on a “12-month rolling average”.

(c) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in H-1X, H-2, H-3, H-200 and H-300 shall not exceed 70 ppmvd total sulfur calculated as H_2S on a “12-month rolling average” basis.

Compliance Determination Requirements

D.1.9 Compliance Determination Requirements

(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.1.3 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, compliance with the NO_X emissions limit in Condition D.1.2(a) for Heater H-200 and H-1X shall be calculated using 40 CFR Part 60, Appendix A, Method 19 and either the 12-month rolling average NO_X concentration as determined by CEMS (after the installation of the CEMS required by Condition D.1.13(b)) or the NO_X concentration measured in the most recent stack test demonstrating compliance (prior to the installation of the CEMS required by Condition D.1.13(b)).

D.1.10 Performance Testing Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to demonstrate compliance with the emission limits in Condition D.1.2(b)(3), the Permittee shall conduct performance tests to measure emissions of NO_X from Heater H-300 once every five (5) years. For the measurement of NO_X emissions, the Permittee shall comply with the performance test protocols established by EPA Method 7E in conjunction with either EPA Method 19 or EPA Methods 1, 2, 3 and 4, or an EPA-approved alternative test method.

Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee’s requirements with regards to the initial compliance demonstration for NO_X testing for Heater H-300.

(b) Pursuant to SSM 089-32033-00453, the Permittee shall perform NO_X testing of Heaters H-2 and H-3 at least once every five (5) years from the date of the most recent valid compliance demonstration. Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee’s requirements with regards to the initial compliance demonstration for NO_X testing of Heaters H-2 and H-3.

(c) Pursuant to SSM 089-32033-00453, the Permittee shall perform PM, PM_{10}, CO, and VOC testing of Heaters H-1X, H-2, H-3, and H-300 at least once every five (5) years from the date of the most recent valid compliance demonstration. Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee’s requirements with regards to the initial compliance demonstration for PM, PM_{10}, CO, and VOC testing of Heaters H-1X, H-2, H-3, and H-300.

(d) Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the ultra low- NO_X burners, the Permittee shall perform PM, PM_{10}, CO, and VOC testing of Heater H-200. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration.

(e) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures) and utilizing methods approved by the commissioner. Section C – Performance Testing contains the Permittee’s obligation with regard to the performance testing required by this condition.

D.1.11 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in Heaters H-1X, H-2, H-3, H-200 and H-300. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and to demonstrate compliance with Conditions D.1.2(a) and D.1.8,by no later than December 31, 2013 the Permittee shall install, operate, calibrate and maintain a NO_X CEMs on Heaters H-1X and H-200. The Permittee shall install, certify, calibrate, maintain, and operate the NO_X CEMS in accordance with the provisions of 40 CFR § 60.13 that are applicable to CEMs (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B. Unless Appendix F requirements are specifically required by NSPS or state regulations, then in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct either a RAA or a RATA on each CEMS at least once every three (3) years. The Permittee shall conduct a Cylinder Gas Audit each Calendar Quarter during which a RAA or a RATA is not performed.

(c) The Total Sulfur Continuous Analyzer and the NO_X emission monitoring systems (CEMS) shall be calibrated, maintained, and operated for measuring total sulfur and NO_X in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment. The SO_2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO_2.

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 the compliance status with Conditions D.1.3 and D.1.7, 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 and to document the compliance status 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 Ja and to document the compliance status with Condition D.1.4, the Permittee shall maintain the records specified in Section F.3.

(d) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.1.5(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR Plan.

(e) Pursuant to 40 CFR 60, Subparts GGGa to document the compliance status with Conditions D.1.5(b), the Permittee shall keep records as specified in Section F.9.

(f) In order to document the compliance status with Condition D.1.2, the Permittee shall maintain records of monthly firing rates and SO_2 emissions for H-1X, H-2, H-3, H-200, and H-300.

(g) Pursuant to 326 IAC 3-5-6 and to document the compliance status 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.

(h) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligation with regards to the records required by Paragraphs (a), (b), (d), (f), and (g) of this condition.

D.1.14 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Conditions D.1.3 and D.1.7, the Permittee shall submit a report to the IDEM, OAQ not later than 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 Ja and to document the compliance status with Condition D.1.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section F.3.

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.1.5(a), the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) Pursuant to 40 CFR 60, Subparts GGGa to document the compliance status with Conditions D.1.5(b), the Permittee shall submit records as specified in Section F.9.

(e) In order to document the compliance status with Condition D.1.2, the Permittee shall submit a quarterly summary of the monthly firing rates and SO_2 emissions for heaters H-200, H-300, H-1X, H-2, and H-3 not later than thirty (30) days after the end of the quarter being reported.

(f) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Condition D.1.2 and D.1.10, the Permittee shall submit reports of excess SO_2 emissions at heaters H-1X, H-2, H-3, H-200, and H-300, and excess NO_X emissions at heaters H-1X and H-200 not later than 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) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (c), (e), and (f) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.2 EMISSIONS UNIT OPERATION CONDITIONS - No. 11B Coker and Coke Pile, Coker 2 and Coke Handling System

Emissions Unit Description:

(b) Cokers

(1) 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:

(A) 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

(B) 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'.

(C) 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.

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

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

(2) Coker 2, constructed as part of WRMP 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 Coker 2 heaters F-201, F-202, and F-203 are equipped with Selective Catalytic Reduction (SCR) for control of NO_X. The Coker 2 heater stacks have continuous emissions monitors (CEMS) for NO_X and CO. 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:

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

(B) 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.

(C) The Coker 2 is connected to the South flare and associated flare gas recovery system FGRS1 (included in Section D.35). The system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(D) One (1) storage tank, identified as TK-6254, with a maximum storage capacity of 14,028,000 gallons storing coker resid at a vapor pressure less than 0.5 psia. Tank TK-6254 is equipped with a fixed roof and controlled by an iron sponge.

(E) Six (6) natural gas fired heaters rated at 1.0 mmBTU/hr each used for heating tank TK-6254.

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

(G) Miscellaneous process vent emissions, which are routed to the South Flare and associated flare gas recovery system FGRS1 (included in Section D.35).

(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 PM_{10} 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 PM_{10} 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) Pursuant to 326 IAC 6.8-1-2, particulate matter emissions from F-201, F-202, F-203, and the TK-6254 heaters shall each 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 2-1.1-4] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4 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 Coker 2 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 WRMP project.

For each of the heaters F-201, F-202, and F-203:

(c) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and pursuant to Permit SSM 089-25484-00453, issued May 1, 2008, the emissions of NO_X from each heater 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 SO_2 from each heater shall not exceed 10.1 tons per 12 consecutive month period, with compliance determined at the end of each month.

(f) Pursuant to SSM 089-32033-00453, the emissions of PM shall not exceed 0.0081 pounds per million BTU.

(g) The emissions of PM_{10} shall not exceed 0.0081 pounds per million BTU.

(h) 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.

(i) 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
F-201	1822.1
F-202	1822.1
F-203	1822.1

(j) Pursuant to SSM 089-32033-00453, each of the six (6) natural gas fired heaters rated at 1.0 mmBTU/hr each used for heating tank TK-6254 shall comply with the following:

SO_2 (lb/mmBTU)	CO (lb/mmBTU)	VOC (lb/mmBTU)	NOx (lb/mmBTU)	PM (lb/mmBTU)	PM_{10} (lb/mmBTU)
0.0006	0.082	0.0054	0.098	0.0075	0.0075

For heavy liquid pumps:

(k) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.2.6. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

For the coker feed tank TK-6254:

(l) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, emissions of H_2S from the TK-6254 shall not exceed 2.84 tons per rolling 12 month period, with compliance determined at the end of each month. Emissions during periods when the iron sponge is offline for maintenance shall be included in determining compliance with this emission limit.

(m) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, emissions of VOC from the TK-6254 shall not exceed 10.0 tons per rolling 12 month period, with compliance determined at the end of each month.

Compliance with the coker throughput limits and limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

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-6254, 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.2.15(g).

D.2.5 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the date of initial start-up, Heaters F-201, F-202 and F-203 shall be affected facilities for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for Heaters F-201, F-202 and F-203.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207, Heaters F-201, F-202 and F-203 shall be affected facilities for NO_X as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja for NO_X emissions for process heaters by the date specified in 40 CFR 60, Subpart Ja. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for Heaters F-201, F-202 and F-203.

D.2.6 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the #2 Coker is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the “Date of Entry” of the Consent Decree entered in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the #2 Coker no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

(c) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the 11B Coker is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the “Date of Entry” of the Consent Decree entered in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the 11B Coker no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The 11B Coker shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.2.7 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 Coker 2 and Coke Handling System upon startup:

Pursuant to 326 IAC 6.8-10-3(3)(A), (3)(B), (5), and (6), the Permittee shall comply with the opacity limitations in Section C - 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.2.8 Particulate Matter Requirements [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 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 Attachment A, or the most recent version submitted to IDEM. 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, the Permittee shall control fugitive particulate matter emissions from the Coker 2 and Coke Handling System according to the Fugitive Dust

Control Plan (FDCP), included as Attachment A, or the most recent version submitted to IDEM. 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.2.9 Consent Decree (Civil No. 2:12-CV-00207) Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, "fuel oil" shall not be burned in #2 Coker Heaters F-201, F-202 and F-203 and the six (6) natural gas fired heaters used for heating tank TK-6254.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in F-201, F-202 and F-203 shall not exceed 70 ppmvd total sulfur calculated as H_2S on a "12-month rolling average" basis.

(c) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon initial startup of the #2 Coker, the Permittee shall not commence Coke Drum Venting until the "Coke Drum Overhead Pressure" is 2.0 psig or less.

As specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the "Coke Drum Overhead Pressure" shall mean the difference between the absolute pressure inside a Coke Drum and atmospheric pressure, expressed as psig, as measured on the coke drum overhead vapor line, during the coke steaming and quenching operations prior to commencing Coke Drum Venting.

(d) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon initial startup of the #2 Coker, pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the Permittee shall comply with the following operating limits for the #2 Coker:

(1) Total Quench Water added to a coke drum shall be at least 260,000 gallons per cycle or until the water reaches the high level trip in the Coke drum, whichever is less; and

(2) "Quench Water Soak Time" shall be at least 45 minutes per cycle.

As specified by the Consent Decree entered in Civil No. 2:12-CV-00207, "Quench Water Soak Time" shall mean the duration of time from the end of the Quench Water Fill Time and the start of Quench Water draining.

(e) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the initial startup of the #2 Coker, pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, for all components and pieces of equipment within the Quench Water System other than the Coke Pit, the Maze (coke fines settling basin), clean water sump and Quench Water Tank, the Permittee shall maintain a hard-piped system that has no emissions points to the atmosphere.

(f) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the initial startup of the #2 Coker, pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the Permittee shall use only the following for the #2 Coker Quench Water Make-Up:

(1) Water that is fresh (i.e., water brought into the Whiting Refinery that has not been in contact with process water or process wastewater);
(2) Non-contact cooling water blowdown;
(3) Water that has been stripped in a sour water stripper;
(4) Water from other refinery sources where the water has a TOC concentration of less than 745 ppm and a total sulfide concentration of less than 35 ppm; or
(5) Some combination of water from 1-4.

(g) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the initial startup of the #2 Coker, pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the Permittee shall not feed or dispose of any materials with a TOC concentration of 745 ppm or greater into any #2 Coker Coke Drum during the quench cycle.

(h) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, the Coker Feed Tank (TK-6254) shall be equipped with a fixed roof, shall be nitrogen blanketed and shall be vented to an iron sponge control system except during periods when the iron sponge is offline for maintenance.

(i) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, the Coke Pit shall have walls on all four sides that are at least forty feet (40') above the floor of the Coke Pit.

(j) Until the shutdown of the No. 11B Coker and the associated emissions units:

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and 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 H-101, H-102, H-103 and H-104.

Compliance Determination Requirements

D.2.10 Operating Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to demonstrate compliance with Condition D.2.2, the Permittee shall operate the heaters F-201, F-202, and F-203 using only Ultra low-NO_X burners.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to demonstrate compliance with Condition D.2.2, the SCRs shall “continuously operate” for heaters F-201, F-202, and F-203. As specified by the Consent Decree entered in Civil No. 2:12-CV-00207, “continuously operate” shall mean, with respect to SCR, that it shall be used at all times the associated unit is in operation, except as necessary for consistency with the manufacturer’s specifications and good engineering and maintenance practices for such equipment and the unit.

(c) Pursuant to Permit SSM 089-25484-00453, issued May 1, 2008, and in order to comply with Condition D.2.2, the Permittee shall use wet suppression to control emissions of PM and PM_{10} from transfer points 1 through 10 at Coker 2 as necessary to ensure that the coke processed has a moisture content greater than eight percent (8%). The suppressant shall be applied in a manner and at a frequency sufficient to ensure compliance with Condition D.2.2.

D.2.11 Compliance Determination Requirements

(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.2.3 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, compliance with the NO_X in Condition D.2.2(c) for Heaters F-201, F-202, and F-203 shall be calculated using the following equation:

E_{tpy} = lb/mmBTU [NO_X] * H * 1 ton/2000 lbs.			
Where:			
	E_{tpy}	=	Stack [NO_X] emissions in tons per year
	lb/mmBTU	=	lb/mmBTU calculated using 40 CFR Part 60, Appendix A, Method 19, using the average concentration as measured by the CEMS over the preceding 12 months.
	H	=	Total heat input in mmBTU to the unit from all fuels fired in the unit over the previous rolling 12-month period

(c) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to demonstrate compliance with condition D. 2.2.(l), the Permittee shall monitor the daily average H_2S concentration at the outlet of the iron sponge system from TK-6254 and shall determine the daily average vapor flow based on the nitrogen purge to TK-6254. The H_2S concentration and nitrogen purge flow will be used to calculate the H_2S emission rate. Process analyzers calibrated in accordance with the manufacturer's recommendations may be used for this purpose.

(d) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to demonstrate compliance with condition D.2.2.(m), on a monthly basis, the Permittee shall monitor the VOC concentration at the outlet of the iron sponge system in accordance with Paragraph 52.a.ii and 52.b.ii of the Consent Decree entered in Civil No. 2:12-CV-00207 and shall verify and record that flow is present when the VOC concentration is measured at the tank vent. The Permittee shall determine the monthly average vapor flow based on the nitrogen purge rate to TK-6254. The VOC concentration and nitrogen purge flow will be used to calculate the VOC emissions rate.

D.2.12 Performance Testing

Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the Coker 2, the Permittee shall perform PM, PM_{10}, and VOC testing of Heaters F-201, F-202, and F-203 utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.2.13 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in F-201, F-202 and F-203.

The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, and to demonstrate compliance with Condition D.2.2(c), the Permittee shall install, operate, calibrate and maintain a NO_X CEMs on Heaters F-201, F-202 and F-203. The Permittee shall install, certify, calibrate, maintain, and operate the NO_X CEMS in accordance with the provisions of 40 CFR § 60.13 that are applicable to CEMs (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B. Unless Appendix F requirements are specifically required by NSPS or state regulations, then in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct either a RAA or a RATA on each CEMS at least once every three (3) years. The Permittee shall conduct a Cylinder Gas Audit each Calendar Quarter during which a RAA or a RATA is not performed.

(c) The Total Sulfur Continuous Analyzer, NO_X and CO continuous emission monitoring systems (CEMS) shall be calibrated, maintained, and operated for measuring total sulfur, NO_X, and CO in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment. The SO_2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO_2.

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

D.2.14 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.2.15 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document the compliance status with Conditions D.2.3 and D.2.8, the Permittee shall maintain a daily record of the following for the No. 11B Coker process heaters H-101, H-102, H-103 and H-104:

(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 and to document the compliance status 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 Ja and to document the compliance status with Condition D.2.5, the Permittee shall maintain the records specified in Section F.3.

(d) Pursuant to 326 IAC 8-4-8 and to document the compliance status 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 to document the compliance status with Conditions D.2.6(b) and (c), the Permittee shall keep records as specified in Section F.9.

(f) Pursuant to 326 IAC 6.8-10-4(4) and to document the compliance status with Condition D.2.7, 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.

(g) 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-6254 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.

(h) In order to document the compliance status with Condition D.2.2, the Permittee shall maintain records of monthly firing rates and CO, NO_X, and SO_2 emissions for heaters F-201, F-202, and F-203.

(i) In order to document the compliance status with Condition D.2.2, the Permittee shall maintain records of monthly coke throughput at the Coker 2.

(j) Pursuant to 326 IAC 3-5-6 and to document the compliance status 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.

(k) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to document compliance with Condition D.2.2(l), the Permittee shall maintain records of daily average H_2S concentration at the outlet of the iron sponge system and the daily average vapor flow based on the nitrogen purge rate to TK-6254.

(l) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to document compliance with Condition D.2.2(m), the Permittee shall maintain records of the VOC concentration at the outlet of the iron sponge system and record if flow is present when the VOC concentration is measured at the tank vent.

(m) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligation with regards to the records required by Paragraphs (a), (b), (d), (f), (i), (g), (i), (j), (k) and (l) of this condition.

D.2.16 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Conditions D.2.3 and D.2.13 the Permittee shall submit a report to IDEM, OAQ not later than 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 Ja and to document the compliance status with Condition D.2.5, the Permittee shall submit to IDEM, OAQ the reports specified in Section F.3.

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status 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 to document the compliance status with Conditions D.2.6(b) and (c), the Permittee shall submit reports as specified in Section F.9.

(e) Pursuant to 326 IAC 6.8-10-4(4)(G) and to document the compliance status with Condition D.2.8, a quarterly report shall be submitted not later than 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

(f) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.2.2 and D.2.13, the Permittee shall submit reports of excess SO_2, CO NO_X emissions at heaters F-201, F-202, and F-203 not later than 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) In order to document the compliance status with Condition D.2.2, the Permittee shall submit quarterly reports for the monthly firing rates, and CO, NO_X, and SO_2 emissions at heaters F-201, F-202, and F-203, and H_2S and VOC emissions at TK-6254 not later than thirty (30) days of the end of each quarter.

(h) In order to document the compliance status with Condition D.2.2, the Permittee shall submit quarterly reports for the coke throughput at the Coker 2 and the number of hours the coke handling operated under alternative operating scenario not later than thirty (30) days of the end of each quarter.

(i) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (c), (e), (f), (g), and (h) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.3 EMISSIONS UNIT OPERATION CONDITIONS – No. 12 Pipe Still

Emissions Unit Description:

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the WRMP 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 WRMP project. Also, as part of the WRMP Project, there will be upgrades made to the atmospheric and vacuum distillation towers and various heat exchangers and associated piping. 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	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 (SPM 089-25488-00453)	355	130-05	Ultra low- NO_X burners
H-101B*	Permitted in 2008 (SPM 089-25488-00453)	355	130-07	Ultra low- NO_X burners
H-102*	Permitted in 2008 (SPM 089-25488-00453)	331	130-06	Ultra low- NO_X burners

*Heaters H-101A, H-101B, and H-102 have continuous emissions monitors (CEMS) for NO_X and CO.

(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. D-7 was permanently decommissioned as part of the WRMP.

(3) The No. 12 Pipestill, after modifications, will be connected to the South flare and associated flare gas recovery system FGRS1 (included in Section D.35). The system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(4) Leaks from process equipment, including compressors (K-1, K-1A, K-1B, K-101A, K-101B and K-101C), valves, pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and flanges and heat exchange systems. Compressors K-1, K-1A, and K-1B will be shut down as part of WRMP.

(5) Miscellaneous process vent emissions, which are routed to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35).

(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, 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 WRMP 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	0.0075	4.918

(b) Until the shutdown of heaters H-1CN and H-1CX, pursuant to 326 IAC 6.8-2-6, 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.

D.3.2 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2, 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	
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 Standards of Peformance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the date of startup, Heaters H-101A, H-101B and H-102 shall be affected facilities for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for Heaters H-101A, H-101B and H-102.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, Heaters H-101A, H-101B and H-102 shall be affected facilities for NO_X as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja for NO_X emissions for process heaters by the date specified in 40 CFR 60, Subpart Ja. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for 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 2-1.1-4] 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.

(b) In order to render 326 IAC 2-2-8, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable:

(1) Pursuant to Permit SSM 089-25484-00453 (issued May 1, 2008), 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 CO limits determined at the end of each month:

Heater ID	CO tons (per 12 consecutive month period)	VOC (lb/mmBTU)	PM_{10} (lb/mmBTU)
H-101A	29.5	0.0054	0.0075
H-101B	29.5	0.0054	0.0075
H-102	27.5	0.0054	0.0075

(2) Pursuant to SSM 089-32033-00453, Permittee shall comply with the following PM emission limits for the heaters identified as H-101A, H-101B and H-102, with compliance determined at the end of each month.

Heater ID	PM (lb/mmBTU)
H-101A	0.0075
H-101B	0.0075
H-102	0.0075

(3) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and pursuant to Permit SSM 089-25484-00453 (issued May 1, 2008), the Permittee shall comply with the following limits for the heaters identified as H-101A, H-101B and H-102.

Heater ID	NO_X tons per 12 consecutive month period
H-101A	77.7
H-101B	77.7
H-102	72.5

(4) 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

(5) The Permittee shall comply with the following limits following completion of the WRMP project:

Heater ID	SO_2 tons per 12 consecutive month period
H-101A	17.2
H-101B	17.2
H-102	16.0

(6) 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 WRMP project.

(7) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.3.6. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.3.6 Equipment Leaks of VOC [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the No. 12 Pipestill shall be an affected facility for purposes of 40 CFR Part 60, Subpart GGGa, upon the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at the No. 12 Pipestill no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) Prior to the modifications of No. 12 Pipestill made as part of the projects authorized by SSM 089-25484-00453, the No. 12 Pipestill shall not be subject to

the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.3.7 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.

D.3.8 Consent Decree (Civil No. 2:12-CV-00207) Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and pursuant to SPM 089-15202-00003, issued April 24, 2002, "fuel oil" shall not be used as fuel for the No. 12 Pipe Still Heaters H-1AN, H-1AS, H-1B, H-2, H-1CN, H-1CX, H-101A, H-101B and H-102.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in H-101A, H-101B and H-102 shall not exceed 70 ppmvd total sulfur calculated as H_2S on a "12-month rolling average" basis.

Compliance Determination Requirements

D.3.9 Operating Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to demonstrate compliance with Condition D.3.5(b)(3), the heaters H-101A, H-101B, and H-102 shall operate using ultra-low NO_X burners only.

D.3.10 Performance Testing Requirements [326 IAC 2-7-6(1),(6)][326 IAC 2-1.1-11]

Pursuant to SSM 089-32033-00453, not later than 180 days after the re-startup of the No. 12 Pipe Still, the Permittee shall perform PM, PM_{10}, and VOC testing of Heaters H-101A, H-101B, and H-102 utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.3.11 Compliance Determination Requirements

(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.3.3 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, compliance with the NO_X limits in Condition D.3.5(b)(3) shall be calculated using the following equation:

E_{tpy} = lb/mmBTU [NO_X] * H * 1 ton/2000 lbs.			
Where:			
	E_{tpy}	=	Stack [NO_X] emissions in tons per year
	lb/mmBTU	=	lb/mmBTU calculated using 40 CFR Part 60, Appendix A, Method 19, using the average concentration as measured by the CEMS over the preceding 12 months.
	H	=	Total heat input in mmBTU to the unit from all fuels fired in the unit over the previous rolling 12-month period

D.3.12 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in Heaters H-101A, H-101B and H-102. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than December 31, 2013, the Permittee shall install, operate, calibrate and maintain a NO_X CEMs on Heaters H-101A, H-101B and H-102. The Permittee shall install, certify, calibrate, maintain, and operate the NO_X CEMS in accordance with the provisions of 40 CFR § 60.13 that are applicable to CEMs (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B. Unless Appendix F requirements are specifically required by NSPS or state regulations, then in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct either a RAA or a RATA on each CEMS at least once every three (3) years. The Permittee shall conduct a Cylinder Gas Audit each Calendar Quarter during which a RAA or a RATA is not performed.

(c) The Total Sulfur Continuous Analyzer, NO_X and CO continuous emission monitoring systems (CEMS) shall be calibrated, maintained, and operated for measuring total sulfur, NO_X, and CO in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment. The SO_2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO_2

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 Record Keeping Requirements

(a) Pursuant to 40 CFR 60, Subparts Ja and to document the compliance status with Condition D.3.4, the Permittee shall maintain the records specified in Section F.3.

(b) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.3.6(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(c) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Conditions D.3.6(b), the Permittee shall keep records as specified in Section F.9.

(d) In order to document the compliance status with Condition D.3.5, the Permittee shall maintain records of the monthly firing rates and CO, SO_2, and NO_X emissions at heaters H-101A, H-101B, and H-102.

(e) Pursuant to 326 IAC 3-5-6 and to document the compliance status with Condition D.3.12, 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.

(f) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (c), (d), and (e) of this condition.

D.3.15 Reporting Requirements

(a) Pursuant to 40 CFR 60, Subpart Ja and to document the compliance status with Condition D.3.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section F.3.

(b) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.3.6(a), the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(c) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Conditions D.3.6(b), the Permittee shall submit reports as specified in Section F.9.

(d) In order to document the compliance status 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, NO_X, and SO_2 emissions for heaters H-101A, H-101B, and H-102 not later than thirty (30) days after the end of the quarter being reported.

(e) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.3.5 and D.3.12, the Permittee shall submit reports of excess SO_2, NO_X and CO emissions not later than 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

(f) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (b), (d), and (e) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS - Sulfur Recovery Complex

Emissions Unit Description:

(d) The Sulfur Recovery Plant (SRP), 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 WRMP Project, increasing the capacity to 1,300 long tons per day of sulfur. Additional sulfur capacity can be achieved with oxygen enrichment in the C, D and E Claus trains as part of the original WRMP design with no increase in permitted emissions. 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 tailgas 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 WRMP project.

(3) One (1) tailgas 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 WRMP 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 WRMP 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 WRMP project.

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

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

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

(9) Caustic soda storage tanks and sodium bisulfite storage tanks, and handling equipment to be decommissioned as part of the WRMP 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 WRMP 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. As specified by the Federal Consent Decree from United States, et al. v BP Products North America Inc, Civil No. 2:12-CV-00207 (N.D. Ind. Hammond Div., May 23, 2012), the SRU Flare was permanently decommissioned on August 12, 2013 by the installation of a welded blind on the piping.

(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 WRMP project.

(13) Two (2) modular degassing units, to be installed as part of the WRMP 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 WRMP 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 WRMP project, the sulfur pits A, B and C will be decommissioned and replaced with sealed sulfur collection drums. These sulfur drums are vented to the SRU A/B/C tailgas lines which are routed to either TGU A and/or TGU B.

(15) Two (2) new SRU D and E sulfur trains, to be installed as part of the WRMP project, have two (2) sealed sulfur collection drums which will be used to store molten sulfur. These drums are vented to the SRU D/E tailgas lines, which are routed to either TGU A and/or TGU B.

(16) One (1) sour water storage tank, identified as TK-431, with a maximum storage capacity of 845,600 gallons and used to store material that has a vapor pressure of less than 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 TGU A and TGU B, to be installed as part of the WRMP project, thermal oxidation systems which combust natural gas, each rated at 72 mmBTU/hr, equipped with SO_2 and CO CEMS, and NOx CEMS approved in 2015 for installation, exhausting at stacks S/V 162-06 and 162-07.

(19) Two (2) sulfur storage tanks, identified as TK-315 and TK-316, 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 WRMP Project and are both fixed roof tanks controlled by a steam blanketed, water eductor system routed back to the process .

(20) One (1) Sulfur loading operation to be installed as part of the WRMP Project.

(21) The Sulfur Recovery Plant, after installation of TGU A and TGU B, will be connected to the South flare and associated flare gas recovery system FGRS1 (included in Section D.35). The system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

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

(23) Miscellaneous process vent emissions, which are routed to the South Flare and associated flare gas recovery system FGRS1 (included in Section D.35).

<u>Main Operating Scenario Pre WRMP:</u>
Approximately 80% of tailgases from the three WRMP trains are sent to the B/S TGU, with the remainder sent to the SBS TGU.

Alternate Operating Scenario #1 Pre WRMP:
One train and the B/S TGU are not operated. Tailgases from the other two trains are sent to the SBS TGU.

Alternate Operating Scenario #2 Pre WRMP:
The B/S TGU is not operated. Tailgases from the three trains are sent to the SBS TGU.

Alternate Operating Scenario #3 Pre WRMP:
The SBS TGU is not operated. Tailgases from the three trains are sent to the B/S TGU.

Main Operating Scenario Post WRMP:
The tailgases from the five trains are sent to both of the TGUs.

Alternate Operating Scenario #1 Post WRMP:
One of the TGUs is not operated and the tailgases from the five trains are sent to the other TGU.

(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, particulate matter emissions from SBS TGU (until shutdown), each of the two (2) offgas treaters/thermal oxidizers identified as TGU A and TGU B, 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 326 IAC 6.8-2-6, until it is shutdown, the PM_{10} 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, the PM_{10} emissions from the Sulfur Recovery Unit Incinerator, until it is shutdown, shall not exceed 0.0075 lb/mmBTU and 0.285 lb/hr.

D.4.3 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 TailGas Unit (B/S TGU) (until shutdown)	None	53.10 Total Reduced Sulfur calculated as SO_2
Sodium Bisulfite TailGas Unit (SBS TGU) (until shutdown)	None	9.0

(b) Pursuant to 326 IAC 7-4.1-1, the offgas treaters/thermal oxidizers identified as TGU A and TGU B 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 the requirements of 326 IAC 2-3 (Emission Offset) not applicable.

(c) In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(1) The PM_{10} emissions from TGU A and TGU B each shall not exceed 0.0075 pounds per million BTU.

(2) Pursuant to SSM 089-32033-00453, the PM emissions from TGU A and TGU B each shall not exceed 0.0075 pounds per million BTU.

(3) The VOC emissions from each TGU A and TGU B shall not exceed 0.0054 pounds per million BTU.

(4) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than 60 days after the maximum production rate at which the later of the two new Claus Sulfur Recovery Units (Claus D and E trains) and associated Claus Offgas Treaters (TGU A and TGU B) being installed as a part of WRMP will be operated, or 180 days after initial startup, whichever comes first, the combined SO_2 emissions from TGU A and TGU B shall not exceed 194.8 tons per each rolling 12 month period, with compliance determined at the end of each month.

(5) The combined CO emissions from TGU A and TGU B shall not exceed 55.0 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(6) Prior to the installation of the NOx CEMS on TGU A and TGU B, the NO_X emissions from TGU A and TGU B each shall not exceed 0.08 pounds per million BTU.

(7) The Permittee shall comply with the following firing rate limit:

Unit ID	Firing Rate (10^3 mmBTU) per 12 consecutive month period
TGU A and TGU B (total)	1261.4

(8) After the installation of the NOx CEMS on TGU A and TGU B, the combined NOx emissions from TGU A and TGU B shall not exceed 50.5 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(9) The B/S TGU, SBS TGU, and SBS Cooling tower shall be permanently shutdown prior to the completion of the WRMP project.

(10) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.4.6. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.4.5 Standards of Peformance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the Sulfur Recovery Plant shall be an “affected facility” as that term is used in 40 CFR 60, Subparts A and Ja, for all pollutants applicable to SRPs, and shall be subject to and comply with all applicable requirements of 40 CFR 60, Subparts A and Ja except as provided below:

(a) Each of the two new Claus sulfur recovery units (Claus D and E trains) and Claus Offgas Treaters (TGU A and TGU B) being installed as a part of WRMP, shall achieve and thereafter maintain compliance with the emission limit in 40 CFR § 60.102a(f)(1)(i) and the monitoring requirements in 40 CFR § 60.106a(a)(1) by no later than 60 days after achieving the maximum production rate at which the unit will be operated, or 180 days after initial startup, whichever comes first.

(b) The Beavon-Stretford TGU (B/S TGU) and the SBS TGU units shall be shut down and permanently removed from service by no later than 180 days after the initial startup of the later of the two sulfur recovery units (Claus D and E trains) and Claus Offgas Treaters (TGU A or TGU B) being installed as a part of WRMP. Initial startup of the two new Claus sulfur recovery units and Claus Offgas Treaters shall be by no later than the initial startup of the New Coker. Until the B/S TGU unit is shut down the Permittee shall continue to monitor emissions from that unit and determine compliance with the emission limits in 40 CFR §60.102a(f)(1) in accordance with the monitoring procedure specified in Appendix C of the Consent Decree in Civil No. 2:12-CV-00207.

D.4.6 Equipment Leaks of VOC [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, upon completion of modifications to the Sulfur Recovery Plant authorized by SSM 089-25484-00453 or upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, whichever is sooner, the Sulfur Recovery Plant shall be an affected facility for purposes of 40 CFR 60, Subpart GGGa, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the Sulfur Recovery Plant no later than one year from the “Date of Entry” of the Consent Decree entered in Civil No. 2:12-CV-00207.

(2) The Sulfur Recovery Plant shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.4.7 Operating Requirements

Until the shut down of the sulfur pits, 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 SO_2.

D.4.8 Consent Decree (Civil No. 2:12-CV-00207) Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than 60 days after the maximum production rate at which the later of the two new Claus Sulfur Recovery Units (Claus D and E trains) and associated Claus Offgas Treaters (TGU A and TGU B) being installed as a part of WRMP will be operated, or 180 days after initial startup, whichever comes first, the Sulfur Recovery Plant (SRP) shall comply with the following requirements:

(1) 40 CFR § 60.102a (f)(1)(i) during all periods of operation of the SRP, other than periods of startup, shutdown or malfunction of the SRP or malfunction of a Tail Gas Unit (TGU) to the extent provided under 40 CFR § 60.8.

(2) At all times, including, but not limited to, periods of startup, shutdown, malfunction and maintenance, the Permittee shall, to the extent practicable, operate and maintain the SRP, including its TGU, its sulfur pits and sealed sulfur collection drums, any supplemental control devices on the SRP, and Pit 2400 and the molten sulfur storage tanks, in accordance with its obligation to minimize

emissions through implementation of good air pollution control practices as required by 40 CFRR § 60.11(d). Pit 2400 was shut down prior to May 10, 2014.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than the "Date of Entry" of the Consent Decree entered in Civil No. 2:12-CV-00207, the molten sulfur tanks TK-315 and TK-316 shall be steam or nitrogen blanketed and equipped with a water eductor system that routes H2S emissions back to the sulfur recovery plant at all times, except during periods when the tanks are vented to atmosphere to allow for maintenance on equipment associated with the tank (i.e. valves and level transmitters).

(c) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, Tanks TK-315 and TK-316 shall not be vented to atmosphere except during periods of maintenance on equipment associated with the tank, and during those periods for no more than 100 hours per rolling 12-month period.

(d) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than the "Date of Entry" of the Consent Decree entered in Civil No. 2:12-CV-00207, the Permittee shall comply with the requirements of 40 CFR § 60.102a(f) as it applies to Sulfur Pits A, B and C. Sulfur Pits A, B, and C were shut down prior to May 10, 2014.

(e) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than the "Date of Entry" of the Consent Decree entered in Civil No. 2:12-CV-00207, the Permittee shall continue to operate and maintain the following control and monitoring equipment until Sulfur Pits A, B, C and 2400 are decommissioned:

(1) Pit sweep system for Sulfur Pits A, B, C and 2400;

(2) Temperature indicators located at each eductor inlet at Sulfur Pits A, B, C and 2400; and

(3) Caustic scrubber to treat emissions from Sulfur Pits A, B, C and 2400 in the event that pit sweep emissions are routed to the B/S TGU.

(f) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than the "Date of Entry" of the Consent Decree entered in Civil No. 2:12-CV-00207, the Permittee shall, to the extent practicable, maintain and operate the newly redesigned degas system to minimize the entrainment of H2S vapor in the sulfur routed to Pit 2400 in a manner consistent with good air pollution control practice for minimizing emissions.

(g) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than 180 Days after initial startup of the Coker 2, the Permittee shall replace Sulfur Pits A, B and C with sealed sulfur collection drums, and shall replace Pit 2400 with molten sulfur storage tanks.

(h) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than the date that the Permittee replaces Sulfur Pits A, B and C with sealed collection drums and Pit 2400 with storage tanks, the Permittee shall route all sulfur emissions from the sealed sulfur collection drums and the molten sulfur storage tanks such that they are treated, monitored, and included as part of the SRP's emissions subject to the NSPS Subpart Ja limit for SO2, 40 CFR § 60.102a (f)(1)(i).

(i) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, for a period of one year commencing from the first use of each molten sulfur storage tank, the Permittee shall monitor on a continuous basis and report to EPA on a semi-annual basis the duration of all relief valve releases from each molten sulfur storage tank.

(j) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, nothing in Condition D.4.8(g)&(h) shall preclude the Permittee from undertaking maintenance on the sealed sulfur collection drums consistent with the provisions of 40 C.F.R. § 60.102a(f)(3), or the molten sulfur storage tanks consistent with Condition 4.2.10(c).

Compliance Determination Requirements

D.4.9 Performance Testing Requirements [326 IAC 2-7-6(1), (6)][326 IAC 2-1.1-11]

(a) Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the TGU A thermal oxidation system, the Permittee shall perform PM, PM10 and VOC testing of TGU A utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the TGU B thermal oxidation system, the Permittee shall perform PM, PM10, and VOC testing of TGU B utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(c) Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the TGU A thermal oxidation system, the Permittee shall perform NO_X testing of TGU A utilizing methods approved by the commissioner. Prior to the installation of the NOx CEMS on TGU A, this test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(d) Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the TGU B thermal oxidation system, the Permittee shall perform NO_X testing of TGU B utilizing methods approved by the commissioner. Prior to the installation of the NOx CEMS on TGU B, this test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.4.10 Compliance Determination Requirements

(a) 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.4.3 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, compliance with the SO_2 emission limit in Condition D.4.4(c)(4) shall be determined each month by adding the total emissions for that month to the total emissions for the preceding 11 months. Total emissions for each month shall be determined with CEMS emission data converted by the following equation:

$$E = \left(\frac{F \times C \times MW}{V_m \times 2000 \times 10^6} \right)$$

E	=	TGTU SO_2 Emissions in tons per month
F	=	Measured total TGTU incinerator stack flow rate, dscf at standard conditions (60º F), for the month
C	=	Average concentration of SO_2 in TGTU incinerator, exhaust for the month, in ppmvd
MW	=	Molecular weight of SO_2 = 64.06
Vm	=	379.4 dscf of gas per lb-mol at standard conditions (60º F)
2000	=	conversion factor for 2000 pound per ton
10^6	=	conversion factor for ppmv to volume fraction

D.4.11 Continuous Emissions Monitoring [40 CFR 64]

The SO_2 continuous emission monitoring systems (CEMS) shall be calibrated, maintained, and operated for measuring SO_2 in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment.

D.4.12 Continuous Emissions Monitoring

(a) The CO continuous emission monitoring systems (CEMS) shall be calibrated, maintained, and operated for measuring CO in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment.

(b) After the installation of the NOx continuous emission monitoring systems (CEMS) on TGU A, the CEMS shall be calibrated, maintained, and operated for measuring NOx in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment.

(c) After the installation of the NOx continuous emission monitoring systems (CEMS) on TGU B, the CEMS shall be calibrated, maintained, and operated for measuring NOx in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - 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 the compliance status 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 and to document the compliance status 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 the compliance status 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 the compliance status 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 the compliance status 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 the compliance status 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 Ja and to document the compliance status with Condition D.4.5, the Permittee shall maintain the records specified in Sections F.3.

(h) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.4.6(a), the Permittee shall keep records as specified in the LDAR plan.

(i) Pursuant to 326 IAC 3-5-6 and to document the compliance status with Conditions D.4.10, D.4.11, D.4.12, C.12 and C.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) Nature of system repairs and adjustments.

(j) To document compliance with Condition D.4.6(b), the Permittee shall maintain records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(k) To document compliance status with Condition D.4.8, the Permittee shall maintain records of the duration in hours when Tanks TK-315 and TK-316 are vented to the atmosphere.

(l) To document the compliance status with Condition D.4.4(c)(4), the Permittee shall maintain records of monthly SO_2 emissions for TGUA and TGU B.

(m) To document the compliance status with Condition D.4.4(c)(5), the Permittee shall maintain records of monthly CO emissions for TGUA and TGU B.

(n) To document the compliance status with Condition D.4.4(c)(7), the Permittee shall maintain records of monthly firing rate for TGUA and TGU B.

(o) After the installation of NOx CEMS on TGUA and TGU B, in order to document the compliance status with Condition D.4.4(c)(8), the Permittee shall maintain records of monthly NOx emissions for TGU A and TGU B.

(p) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (c), (d), (e), (f), (h), (i), (k), (l), (m), (n), and (o) of this condition.

D.4.15 Reporting Requirements

(a) Until shut down of the SRU incinerator, the B/S TGU and the SBS TGU, pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Condition D.4.3, the Permittee shall submit a report to IDEM, OAQ not later than 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 Ja and to document the compliance status with Condition D.4.5, the Permittee shall submit to IDEM, OAQ the reports specified in Sections F.3.

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status 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) Until the B/S TGU and SBS are shutdown, a quarterly summary of the information to document the compliance status with Condition D.4.4 shall be submitted not later than thirty (30) days after the end of the quarter being reported

(f) Upon start-up of TGU A and/or TGU B, in order to document the compliance status with Condition D.4.4(c)(4), the Permittee shall submit a quarterly report of monthly emissions of SO_2 from TGU A and TGU B not later than thirty (30) days after the end of each quarter.

(g) Upon start-up of TGU A and/or TGU B, in order to document the compliance status with Condition D.4.4(c)(5), the Permittee shall submit a quarterly report of monthly emissions of CO from TGU A and TGU B not later than thirty (30) days after the end of each quarter.

(h) Upon start-up of TGU A and/or TGU B, in order to document the compliance status with Condition D.4.4(c)(7), the Permittee shall submit a quarterly report of monthly firing rates at TGU A and TGU B not later than thirty (30) days after the end of each quarter.

(i) Upon the installation of the NOx CEMS on TGU A and TGU B, in order to document the compliance status with Condition D.4.4(c)(8), the Permittee shall submit a quarterly report of monthly emissions of NOx from TGU A and TGU B not later than thirty (30) days after the end of each quarter.

(j) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.4.4, D.4.10, D.4.11, D.4.12, C.12, and C.13, the Permittee shall submit reports of excess NOX, SO_2, and CO emissions at TGU A and TGU B not later than 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.

(k) To document compliance with Condition D.4.6(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(l) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (c), (d), (e), (f), (g), (h), (i), (j), and (k) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.5 EMISSIONS UNIT OPERATION CONDITIONS - Vapor Recovery Units 100 and 200

Emissions Unit Description:

(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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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 instrumentation and heat exchange systems. As part of the WRMP Project, there will be upgrades made to various heat exchangers and associated piping and retraying of distillation towers at VRU 100 and VRU 200. 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 hydrocarbon pressure relief discharges that were previously routed to the VRU 100/200 vent stacks, are being re-routed to the VRU flare and associated flare gas recovery system FGRS3 (identified in Section D.35).

(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) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the VRU 100 and VRU 200 shall be affected facilities for purposes of 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree entered in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9– 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the VRU 100 and VRU 200 no later than one year from the “Date of Entry” of the Consent Decree entered in Civil No. 2:12-CV-00207.

(2) VRU 100 and VRU 200 shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.5.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) After the completion of the WRMP project, the hydrocarbon pressure relief discharges that were previously routed to the VRU 100 and VRU 200 vent stacks will be routed to the VRU flare and associated flare gas recovery system FGRS3.

(b) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.5.4. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance Determination Requirements

D.5.3 Operating Requirement

In order to demonstrate compliance with Condition D.5.2, following the completion of the WRMP project, the pressure relief discharges from VRU 100 and VRU 200 shall be routed to the VRU flare and associated flare gas recovery system FGRS3.

Compliance Monitoring Requirements

D.5.4 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 LDAR plan submitted by the Permittee.

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

D.5.5 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.5.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) To document the compliance status with Condition D.5.1(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(c) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraph (a) of this condition.

D.5.6 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.5.1(a), the Permittee shall submit reports as specified in the LDAR plan

(b) To document the compliance status with Condition D.5.1(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(c) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraph (a) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.6 EMISSIONS UNIT OPERATION CONDITIONS - Vapor Recovery Units 300 and 400

Emissions Unit Description:

(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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, there will be upgrades made to various distillation towers, compressor K-340, and associated piping at VRU 300. Upon completion of WRMP, some portions of VRU 300 will be connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or 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 the VRU flare and associated flare gas recovery system FGRS3 (identified in Section D.35).

(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 and heat exchange systems.

(B) Vapor Recovery Unit VRU 400 for the Coker 2, permitted in 2008, to be installed as part of the WRMP project. This unit is connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or 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 K-401), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation and heat exchange systems. The facility may also 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.6.1 Equipment Leaks of Volatile Organic Compounds (VOC) [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 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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the VRU 300 is an affected facility pursuant to 40 CFR 60, Subpart GGGa, , upon the "Date of Entry" of the Consent Decree entered in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the VRU 300 no later than one year from the “Date of Entry” of the Consent Decree entered in Civil No. 2:12-CV-00207.

(2) VRU 300 shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

(4) The two consecutive months of monitoring that the Permittee previously conducted for purposes of 40 CFR 60, Subpart GGGa at VRU 300 satisfies the requirement to conduct monitoring of those components for two consecutive months following the initial applicability of 40 CFR 60, Subpart GGGa.

(c) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the VRU 400 is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the VRU 400 no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.6.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.6.1. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance Monitoring Requirements

D.6.3 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.6.4 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.6.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Conditions D.6.1(b) and (c), the Permittee shall keep records as specified in Section F.9.

(c) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraph (a) of this condition.

D.6.5 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.6.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Conditions D.6.1(b) and (c), the Permittee shall submit reports as specified in Section F.9.

(c) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraph (a) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.7 EMISSIONS UNIT OPERATION CONDITIONS - Alkylation Unit

Emissions Unit Description:

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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 the Alky Flare and associated flare gas recovery system FGRS3 (included in Section D.35).

(2) One (1) spent acid stripper drum (D-13), which exhausts to the Alky Flare and associated flare gas recovery system FGRS3 (included in Section D.35).

(3) One (1) spent caustic drum (D-32), which exhausts to the Alky Flare and associated flare gas recovery system FGRS3 (included in Section D.35).

(4) One (1) spent acid storage tank (Tank 2), constructed in 1960, with a maximum storage capacity of 70,497 gallons, equipped with a fixed roof and controlled by carbon canisters.

(5) 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 and heat exchange 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.7.1 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the Alkylation Unit is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open -ended valve or line, and flange or other connector in VOC service at the Alkylation Unit no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The Alkylation Unit shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the initial notification and testing requirements under 40 CFR §§ 60.7(a), 60.8(a), 60.482-1a(a) and 60.487a(e) that are triggered by initial applicability of 40 CFR Part 60, Subparts A and GGGa.

(4) The two consecutive months of monitoring that the Permittee previously conducted for purposes of 40 CFR 60, Subpart GGGa at the Alkylation Unit satisfies the requirement to conduct monitoring of those components for two consecutive months following the initial applicability of 40 CFR 60, Subpart GGGa.

D.7.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.7.1. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance Monitoring Requirements

D.7.3 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.7.4 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.7.1, the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Conditions D.7.1(b), the Permittee shall keep records as specified in Section F.9.

(c) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraph (a) of this condition.

D.7.5 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.7.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Conditions D.7.1(b), the Permittee shall submit reports as specified in Section F.9.

(c) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraph (a) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.8 EMISSIONS UNIT OPERATION CONDITIONS - Propylene Concentration Unit

Emissions Unit Description:

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control 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 the Alky Flare or FGRS3 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 and heat exchange systems. 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) [326 IAC 8-4-8][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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the Propylene Concentration Unit is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the Propylene Concentration Unit no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The Propylene Concentration Unit shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.8.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.8.1. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance Monitoring Requirements

D.8.3 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.8.4 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.8.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Conditions D.8.1(b), the Permittee shall keep records as specified in Section F.9.

(c) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraph (a) of this condition.

D.8.5 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.8.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Conditions D.8.1(b), the Permittee shall submit reports as specified in Section F.9.

(c) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraph (a) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.9 EMISSIONS UNIT OPERATION CONDITIONS - Isomerization Unit

Emissions Unit Description:

(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, the UIU Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the MSAT II Compliance project approved in 2011 for construction, one (1) new C-250 Naphtha Splitter, a benzene saturation reactor system, and associated equipment (collectively identified as the Naphtha Splitter Unit) will be installed in the ISOM. 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, rated at 190 mmBTU/hr and vented to stack S/V 210-01.

(2) One (1) Flare Knock-out Drum (ISOM D-18), which exhausts to the UIU flare and associated flare gas recovery system FGRS4 (identified in Section D.35).

(3) Leaks from process equipment, including one (1) compressor (identified as K-1), pumps, valves, process drains and pressure relief devices and heat exchange 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.9.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6, PM_{10} emissions from the H-1 Heater (also known as No. 2 Isomerization Feed Heater) furnace shall not exceed 0.0075 lb/mmBTU and 1.416 lb/hr.

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 Heater 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 2-1.1-4] Minor Limits

(a) In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for the H-1 Heater upon issuance of Significant Permit Modification No. 089-25488-00453, unless otherwise specified:

(1) The emissions of NO_X shall not exceed 0.275 pounds per million BTU.

(2) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(3) The emissions of SO_2 shall not exceed 7.4 tons per 12 consecutive month period after the completion of the WRMP project.

(4) The emissions of PM_{10} shall not exceed 0.0075 pounds per million BTU.

(5) Pursuant to SSM 089-32033-00453, the emissions of PM shall not exceed 0.0075 pounds per million BTU.

(6) The emissions of CO shall not exceed 0.082 pounds per million BTU.

(7) The Permittee shall comply with the following limit on firing rate, following the completion of the WRMP project:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period
H-1	1342.03

(8) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.9.5. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

(b) In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable to the MSAT II Compliance Project, the Permittee shall comply with the following upon issuance of Significant Permit Modification No. 089-29033-00453, unless otherwise specified:

(1) Utility hydrogen to the benzene saturation reactor battery limits shall be supplied by the New Hydrogen Unit (HU), Unit ID 801, and not by the existing HU, Unit ID 698.

(2) The combined steam energy usage for the C-250 system (E-253A/B, E-251) and the C-1 system (E-9A) shall not exceed 1,687,693 mmBTU per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with these limitations will ensure that the potential to emit from this modification is less than twenty-five (25) tons of PM per year, less than fifteen (15) tons of PM_{10} per year, less than ten (10) tons of $PM_{2.5}$ per year, less than forty (40) tons per year of NO_X, less than forty (40) tons of SO_2 per year, less than 100 tons of CO per year, less than seven (7) tons of H_2SO_4 per year, less than 0.6 tons of lead per year, less than 0.1 tons of mercury per year, less than 0.0004 tons of beryllium per year, less than ten (10) tons of H_2S per year, and less than twenty-five (25) tons per year of VOC. Therefore, the requirements of 326 IAC 2-2 (PSD) and 326 IAC 2-1.1-4 (Nonattainment NSR) are rendered not applicable.

D.9.4 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the Heater H-1 shall be an affected facility for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for the H-1 Heater.

D.9.5 Equipment Leaks of Volatile Organic Compounds (VOC) [326 IAC 8-4-8][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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the ISOM Unit shall be an affected facility for purposes of 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the ISOM Unit no later than one year from the “Date of Entry” of the Consent Decree entered in Civil No. 2:12-CV-00207.

(2) The ISOM Unit shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.9.6 Operating Requirement

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and pursuant to Permit SPM 089-15202-00003, issued April 24, 2002, "fuel oil" shall not be used as fuel for the H-1 Heater.

D.9.7 Consent Decree (Civil No. 2:12-CV-00207) Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in the H-1 Heater shall not exceed 70 ppmvd total sulfur calculated as H_2S on a "12-month rolling average" basis.

Compliance Determination Requirements

D.9.8 Compliance Determination Requirements

(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 hydrogen usage requirement in Condition D.9.3(b)(1) shall be determined by maintaining the hydrogen supply pressure to the benzene saturation reactor at not less than 295 psig during any time the reactor is in operation.

(c) Compliance with the steam energy usage limit in Condition D.9.3(b)(2) shall be determined by an energy balance calculation, as follows:

Energy Demand (MMBtu/yr) =

$E_{in,400\#}$ (MMBtu/yr) + $E_{in,100\#}$ (MMBtu/yr) + $E_{in,BFW}$ (MMBtu/yr) - $E_{out,100\#}$ (MMBtu/yr) - $E_{out,10\#}$ (MMBtu/yr) - $E_{out,condensate}$ (MMBtu/yr)

Where: E_x (MMBtu/yr) = F_x (lb x/hr) * H_x (Btu/lb) * 10^{-6} (MMBtu/Btu) * 8760 (hr/yr);
F_x (lb x/hr) = steam, condensate, or boiler feed water mass flow rate; and
H_x (Btu/lb) = enthalpy of steam, condensate, or boiler feed water based on known conditions (superheated or saturated, and temperature and/or pressure).

D.9.9 Performance Testing Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, the Permittee shall conduct performance tests to measure the emissions of NO_X from the H-1 Heater once every 5 years. For the measurement of NO_X emissions, the Permittee shall comply with the performance test protocols established by EPA Method 7E in conjunction with either EPA Method 19 or EPA Methods 1, 2, 3 and 4, or an EPA-approved alternative test method.

Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee's requirements with regards to the initial compliance demonstration for NO_X testing of the H-1 Heater.

(b) Pursuant to SSM 089-32033-0045, the Permittee shall perform PM, PM_{10}, CO, and VOC testing of the H-1 Heater at least once every five (5) years from the date of the most recent valid compliance demonstration. Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee's requirements with regards to the initial compliance demonstration for PM, PM_{10}, CO, and VOC testing of the H-1 Heater.

(c) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures) and utilizing methods approved by the commissioner. Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.9.10 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in the H-1 Heater. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) In order to demonstrate compliance with Condition D.9.3 and D.9.7, the Total Sulfur Continuous Analyzer shall be calibrated, maintained, and operated for determining compliance with SO_2 emissions limit from the H-1 Heater in accordance with the applicable requirements in - Section C - Maintenance of Continuous Emission Monitoring Equipment and - Section C - Maintenance of Emission Monitoring Equipment. The SO_2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO_2.

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.9.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document the compliance status with Conditions D.9.2 and D.9.6, the Permittee shall maintain a daily record of the following for the H-1 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 and to document the compliance status with Condition D.9.1, the Permittee shall maintain records for the H-1 Heater as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart Ja and to document the compliance status with Condition D.9.4, the Permittee shall maintain the records specified in Section F.3.

(d) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.9.5(a), the Permittee shall comply with equipment leak record keeping requirements as specified in the LDAR plan.

(e) In order to document the compliance status with Condition D.9.3, the Permittee shall maintain records of monthly firing rates and SO_2 emissions for the H-1 Heater.

(f) Pursuant to 326 IAC 3-5-6 and to document the compliance status 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.

(g) To document the compliance status with Condition D.9.3(b)(1), the Permittee shall maintain daily records of the hydrogen supply pressure to the benzene saturation reactor battery limit.

(h) To document the compliance status with Condition D.9.3(b)(1), the Permittee shall maintain daily records of the operational status of the benzene saturation reactor.

(i) To document the compliance status with Condition D.9.3(b)(2), the Permittee shall maintain a daily record of the steam, condensate, and boiler feed water mass flow rates for the C-250 and C-1 systems.

(j) To document the compliance status with Condition D.9.5(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(k) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (d), (e), (f), (g), (h) and (i) of this condition.

D.9.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Conditions D.9.2 and D.9.6, the Permittee shall submit a report to IDEM, OAQ not later than 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 Heater.

(b) Pursuant to 40 CFR 60, Subpart Ja and to document the compliance status with Condition D.9.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section F.3.

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.9.5(a), the Permittee shall submit reports as specified in the LDAR plan.

(d) In order to document the compliance status with Condition D.9.3, the Permittee shall submit a quarterly summary of monthly firing rates and SO_2 emissions for the H-1 Heater not later than thirty (30) days after the end of the quarter being reported.

(e) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.9.3 and D.9.10, the Permittee shall submit reports of excess SO_2 emissions at the H-1 heater not later than 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

(f) A quarterly report of the information to document the compliance status with Condition D.9.3(b)(2) shall be submitted not later than thirty (30) days after the end of the quarter being reported.

(g) To document compliance with Condition D.9.5(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(h) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (c), (d), (e), and (f) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.10 EMISSIONS UNIT OPERATION CONDITIONS - Aromatics Recovery Unit

Emissions Unit Description:

(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 and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(3) Leaks from process equipment, including pumps, compressors, pressure relief devices, sampling connections systems, open-ended line or valves, flanges and other connectors and heat exchange 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.10.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6, 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)	PM_{10} Limit (lbs/hour)
F-200A	0.0075	1.859
F-200B	0.0075	1.859

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 F-200B 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 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, 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 NO_X shall each not exceed 0.275 pounds per million BTU.

(b) The emissions of CO shall each not exceed 0.082 pounds per million BTU.

(c) The emissions of VOC shall each not exceed 0.0054 pounds per million BTU.

(d) The emissions of PM_{10} shall each not exceed 0.0075 pounds per million BTU.

(e) Pursuant to SSM 089-32033-00453, the emissions of PM shall each not exceed 0.0075 pounds per million BTU.

(f) The Permittee shall comply with the following limits, following the completion of the WRMP project:

Unit ID	Firing Rate (10^3 mmBTU) per 12 month period	SO_2 (tons per 12 consecutive month period)
F-200A	930.75	5.1
F-200B	930.75	5.1

(g) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.10.5. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.10.4 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR, Subpart Ja]

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, ARU Heaters F-200A and F-200B shall be affected facilities for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for ARU F-200A and F-200B.

D.10.5 Equipment Leaks of Volatile Organic Compounds and Hazardous Air Pollutants [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the ARU 200 & ARU 300 are affected facilities pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the ARU 200 and ARU 300 no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The ARU 200 and ARU 300 shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a (e).

(4) The two consecutive months of monitoring that the Permittee previously conducted for purposes of 40 CFR 60, Subpart GGGa at ARU 200 & ARU 300 satisfies the requirement to conduct monitoring of those components for two consecutive months following the initial applicability of 40 CFR 60, Subpart GGGa.

D.10.6 Operating Requirement

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and 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.10.7 Consent Decree (Civil No. 2:12-CV-00207) Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in F-200A and F-200B shall not exceed 70 ppmvd total sulfur calculated as H_2S on a "12-month rolling average" basis.

Compliance Determination Requirements

D.10.8 Compliance Determination Requirements

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.

D.10.9 Performance Testing Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, the Permittee shall conduct performance tests to measure emissions of NO_X from the ARU Heaters F-200A and F-200B once every five years. For the measurement of NO_X emissions, the Permittee shall comply with the performance test protocols established by EPA Method 7E in conjunction with either EPA Method 19 or EPA Methods 1, 2, 3 and 4, or an EPA-approved alternative test method.

Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee's requirements with regards to the initial compliance demonstration for NO_X testing for the ARU Heaters F-200A and F-200B.

(b) Pursuant to SSM 089-32033-00453, the Permittee shall perform PM, PM10, CO, and VOC testing of Heaters F-200A and F-200B. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee's requirements with regards to the initial compliance demonstration for PM, PM10, CO, and VOC testing of Heaters F-200A and F-200B.

(c) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures) and utilizing methods approved by the commissioner. Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.10.10 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in ARU Heaters F-200A and F-200B. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) In order to demonstrate compliance with Conditions 10.3(f) and D.10.7, the Total Sulfur Continuous Analyzer shall be calibrated, maintained, and operated for determining compliance with SO_2 emissions limits for F-200A and F-200B in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment. The SO_2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO_2.

Compliance Monitoring Requirements

D.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.

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

D.10.12 Recordkeeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1) and to document the compliance status with Conditions D.10.2, and D.10.6, 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 and to document the compliance status with Condition D.10.1, the Permittee shall maintain records for the process heaters F-200A and F-200B as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart Ja and to document the compliance status with Condition D.10.4, the Permittee shall maintain the records specified in Section F.3.

(d) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.10.5(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) In order to document the compliance status with Condition D.10.3, the Permittee shall maintain records of the monthly firing rates and SO_2 emissions for F-200A and F-200B.

(f) Pursuant to 326 IAC 3-5-6 and to document the compliance status with Condition D.10.10, 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.

(g) To document compliance with Condition D.10.5(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(h) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (d), (e), and (f) of this condition.

D.10.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Conditions D.10.2 and D.10.6, the Permittee shall submit a report to IDEM, OAQ not later than 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 Ja and to document the compliance status with Condition D.10.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section F.3.

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.10.5(a), the Permittee shall submit reports as specified in the LDAR plan.

(d) In order to document the compliance status with Condition D.10.3, the Permittee shall submit a quarterly summary of the monthly firing rates and SO_2 emissions at F-200A and F-200B not later than thirty (30) days after the end of the quarter being reported.

(e) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.10.3 and D.10.10, the Permittee shall submit reports of excess SO_2 emissions at heaters F-200A and F-200B not later than 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

(f) To document compliance with Condition D.10.5(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(g) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (c), (d) and (e) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.11 EMISSIONS UNIT OPERATION CONDITIONS - Blending Oil Unit

Emissions Unit Description:

(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. The BOU is connected to the 4UF flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP 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 include insignificant activities listed in Section A.4 of this permit:

(1) One (1) process Furnace F-401, constructed in 1972, and modified as part of WRMP, which vents to stack ID SV250-01. The furnace is rated at 35 million Btu per hour 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 and heat exchange 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]

Pursuant to 326 IAC 6.8-2-6, 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.11.2 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 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for the BOU Heater F-401 upon issuance of Significant Permit Modification No. 089-25488-00453, unless otherwise specified:

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, the emissions of NO_X 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_{10} shall not exceed 0.0075 pounds per million BTU.

(e) Pursuant to SSM 089-32033-00453, the emissions of PM shall not exceed 0.0075 pounds per million BTU.

(f) The Permittee shall comply with the following limits following the completion of the WRMP project:

Unit ID	Firing rate (10^3 mmBTU) per 12 month period	SO_2 tons per 12 consecutive month period
F-401	288.38	1.6

(g) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.11.5. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.11.4 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, BOU Heater F-401 shall be an affected facility for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for BOU F-401.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, BOU Heater F-401 shall be an affected facility for NO_X as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja for NO_X emissions for process heaters by the date specified in 40 CFR 60, Subpart Ja. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for BOU Heater F-401.

D.11.5 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the BOU is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the BOU no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The BOU shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.11.6 Operating Requirement

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and 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 BOU Heater F-401 .

D.11.7 Consent Decree (Civil No. 2:12-CV-00207) Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in BOU Heater F-401 shall not exceed 70 ppmvd total sulfur calculated as H_2S on a "12- month rolling average" basis.

Compliance Determination Requirements

D.11.8 Compliance Determination Requirements

(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) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, compliance with the NO_X emissions limit in Condition D.11.3(a) for BOU Heater F-401 shall be calculated using 40 CFR Part 60, Appendix A, Method 19 and the NO_X concentration measured in the most recent stack test demonstrating compliance per Condition D.11.9.

D.11.9 Performance Testing Requirements

Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the modified BOU Heater F-401, the Permittee shall perform NO_X, PM, PM10, CO, and VOC testing of the modified BOU Heater F-401 utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee’s obligation with regard to the performance testing required by this condition.

D.11.10 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in BOU Heater F-401. The

Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) In order to demonstrate compliance with Conditions D.11.3 and D.11.7, the Total Sulfur Continuous Analyzer shall be calibrated, maintained, and operated for determining compliance with SO_2 emissions limits for F-401 in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment. The SO_2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO_2.

Compliance Monitoring Requirements

D.11.11 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.11.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document the compliance status with Conditions D.11.2, and D.11.6, the Permittee shall maintain a daily record of the following for the BOU Heater F-401:

(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 and to document the compliance status 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 Ja and to document the compliance status with Condition D.11.4, the Permittee shall maintain the records specified in Section F.3.

(d) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.11.5(a), the Permittee shall comply with equipment leak record keeping requirements as specified in the LDAR plan.

(e) In order to document the compliance status with Condition D.11.3, the Permittee shall maintain the records of monthly firing rate and SO_2 emissions at F-401.

(f) Pursuant to 326 IAC 3-5-6 and to document the compliance status with Condition D.11.10, 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.

(g) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Conditions D.11.5(b), the Permittee shall maintain the records specified in Section F.9.

(h) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (d), (e), and (f) of this condition.

D.11.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Conditions D.11.2 and D.11.6, the Permittee shall submit a report to IDEM, OAQ not later than 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 Ja and to document the compliance status with Condition D.11.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section F.3.

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.11.5, the Permittee shall submit reports as specified in the LDAR plan.

(d) In order to document the compliance status with Condition D.11.3, the Permittee shall submit a quarterly summary of the monthly firing rate and SO_2 emissions at F-401 not later than thirty (30) days after the end of the quarter being reported.

(e) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.11.3 and D.11.10, the Permittee shall submit reports of excess SO_2 emissions at heater F-401 not later than 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

(f) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Conditions D.11.5(b), the Permittee shall submit reports as specified in Section F.9.

(g) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (b), (d), (e) and (f) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.12 EMISSIONS UNIT OPERATION CONDITIONS - No. 2 Treatment Plant

Emissions Unit Description:
(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 No. 2 Treatment Plant was permanently decommissioned as of December 30, 2008.
(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

SECTION D.13 EMISSIONS UNIT OPERATION CONDITIONS - No. 4 Treatment Plant

Emissions Unit Description:

(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 was permanently decommissioned as of June 17, 2010.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

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

Emissions Unit 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). The loading facilities have been isolated from refinery operations and permanently decommissioned.

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

(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) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the Butane and Propane Storage and Loading Facilities and the Propylene Storage Facility shall be an affected facility for purposes of 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at the Butane and Propane Storage and Loading Facilities and the Propylene Storage Facility no later than one year from the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The Butane and Propane Storage and Loading Facilities and the Propylene Storage Facility shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

(c) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the Propylene Rail Loading Rack shall either comply with the requirements of 40 CFR 60, Subpart GGGa or discontinue operations by no later than December 31, 2012. Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the Propylene Rail Loading Rack shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves. Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 482-2a(e), 482-7a(f), 60.485a(g), and 60.487a(e). The Propylene Rail Loading Racks discontinued operations prior to December 31, 2012.

D.14.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.14.1. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

D.14.3 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.14.4 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 LDAR plan submitted by the Permittee.

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

D.14.5 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.14.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) 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.

(c) Pursuant to OP 000204, issued March 8, 1996 and to document the compliance status with Condition D.14.3, the Permittee shall record and maintain a log of the numbers of minutes of venting of the seven (7) pressurized spheres.

(d) To document compliance with Condition D.14.1(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(e) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b) and (c) of this condition.

D.14.6 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.14.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to OP 000204, issued March 8, 1996 and to document the compliance status with Condition D.14.3, the Permittee shall submit a monthly report of the number of minutes each tank is vented.

(c) To document compliance with Condition D.14.1(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(d) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a) and (b) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.15 EMISSIONS UNIT OPERATION CONDITIONS - No. 3 Ultraformer Unit

Emissions Unit Description:

(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 C-2 Splitter Tower will be shut down and permanently decommissioned as part of the MSAT II Compliance project, approved in 2011 for construction. The unit now consists of the C2 D-18 flare gas separator, the D-24 knock-out drum and associated piping.

The No. 3 Ultraformer is connected to the UIU flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or 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 (C2 D-18) with emissions vented to vessel D 24, which exhausts to the UIU flare and associated flare gas recovery system FGRS4 (identified in Section D.35).

(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 and heat exchange 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.15.1 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-4] and Emission Offset [326 IAC 2-3] Minor Limits

(a) In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

Prior to the completion of the WRMP project, permanently shutdown No. 3 Ultraformer, including 3UF heaters H-1, H-2, and F-7, and the 3UF Reformer, except for the C2 Splitter Tower, the C2 D-18 flare gas separator, the D-24 knock-out drum and associated piping.

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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

(b) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.15.2. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

D.15.2 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the No.3 Ultraformer shall be an affected facility for purposes of 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at the No. 3 Ultraformer no later than one year from the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The No. 3 Ultraformer shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

Compliance Monitoring Requirements

D.15.3 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.15.4 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.15.2(a), the Permittee shall keep records as specified in the LDAR plan.

(b) To document compliance with Condition D.15.2(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(c) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraph (a) of this condition.

D.15.5 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.15.2(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) To document compliance with Condition D.15.2(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(c) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraph (a) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.16 EMISSIONS UNIT OPERATION CONDITIONS - No. 4 Ultraformer Unit

Emissions Unit Description:

(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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. The No. 4 Ultraformer includes the following sources of emissions and may 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 / Ultra Low NOx Burners on and after December 31, 2016
F-3*	242	224-03	None / Ultra Low NOx Burners on and after December 31, 2016
F-4	137	224-04	None
F-5	99	224-04	None
F-6	49	224-04	None
F-7	52	224-05	None

*On and after December 31, 2016, heaters F-2 and F-3 stacks have continuous emissions monitors (CEMS) for NOx.

(2) The No. 4 Ultraformer is connected to the 4UF Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system flare is used to recover or 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 the 4UF Flare and associated flare gas recovery system FGRS4 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 and heat exchange 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.

(6) One (1) gas conditioning system, approved in 2013 for construction, consisting of drums, coolers, piping, pumps, and sewer components.

(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]

Pursuant to 326 IAC 6.8-2-6, 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.16.2 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-4	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 2-1.1-4] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4 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	NO_X (lb/mmBTU)	CO (lb/mmBTU)	VOC (lb/mmBTU)	PM_{10} (lb/mmBTU)
F-1	0.098	0.082	0.0054	0.0075

Heater ID	NO_X (lb/mmBTU)	CO (lb/mmBTU)	VOC (lb/mmBTU)	PM_{10} (lb/mmBTU)
F-2	0.210	0.082	0.0054	0.0075
F-3	0.240	0.082	0.0054	0.0075
F-4	0.275	0.082	0.0054	0.0075
F-5	0.098	0.082	0.0054	0.0075
F-6	0.098	0.082	0.0054	0.0075
F-7	0.098	0.082	0.0054	0.0075
F-8A	0.275	0.082	0.0054	0.0075
F-8B	0.275	0.082	0.0054	0.0075

(b) Pursuant to SSM 089-32033-00453, the Permittee shall comply with the following limits following the completion of the WRMP project:

Unit ID	Firing rate (10^3 mmBTU) per 12 month period	SO_2 (tons per 12 consecutive month period)	PM (lb/mmBTU)
F-1	439.75	2.4	0.0075
F-8A	963.60	5.3	0.0075
F-8B	963.60	5.3	0.0075
F-2	1683.67	9.3	0.0075
F-3	1713.10	9.5	0.0075
F-4	965.03	5.3	0.0075
F-5	867.24	4.8	0.0075
F-6	429.24	2.4	0.0075
F-7	315.36	1.7	0.0075

(c) Pursuant to SSM 089-32033-00453, and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than December 31, 2016, the emissions of NO_X from Heater F-2 and Heater F-3 shall not exceed the following limits based on a "12-month rolling average":

Unit ID	NO_X (lb/mmBTU)
F-2	0.04
F-3	0.04

(d) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.16.5. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.16.4 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, Heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A and F-8B shall be affected facilities for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for Heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A and F-8B.

D.16.5 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the No. 4 Ultraformer is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the No. 4 Ultraformer no later than one year from the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The No. 4 Ultraformer shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the initial notification and testing requirements under 40 CFR §§ 60.7(a), 60.8(a), 60.482-1a(a) and 60.487a(e) that are triggered by initial applicability of 40 CFR Part 60, Subparts A and GGGa.

(4) The two consecutive months of monitoring that the Permittee previously conducted for purposes of 40 CFR 60, Subpart GGGa at No.4 Ultraformer satisfies the requirement to conduct monitoring of those components for two consecutive months following the initial applicability of 40 CFR 60, Subpart GGGa.

D.16.6 Operating Requirement

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and 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-4, F-5, F-6, and F-7 Process Heaters.

D.16.7 Consent Decree (Civil No. 2:12-CV-00207) Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than December 31, 2016, the Permittee shall install, maintain, and continuously operate Ultra-Low NO_X burners on Heaters F-2 and F-3.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A and F-8B shall not exceed 70 ppmvd total sulfur calculated as H_2S on a "12-month rolling average" basis.

Compliance Determination Requirements

D.16.8 Compliance Determination Requirements

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.

D.16.9 Performance Testing Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, the Permittee shall conduct performance tests to measure the emissions of NO_X once every five years from each of the following group of furnaces:

4UF Furnaces F-4, F-5 and F-6 (vented through a common stack, identified as 224-04)

4UF Furnaces F-1, F-8A and F8B (vented through a common stack, identified as 224-01)

For the measurement of NO_X emissions, the Permittee shall comply with the performance test protocols established by EPA Method 7E in conjunction with either EPA Method 19 or EPA Methods 1, 2, 3 and 4, or an EPA-approved alternative test method. The test results shall be compared against a calculated weighted average emission limit based on maximum allowable heater fired duty (mmBTU/hr).

Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee's requirements with regards to the initial compliance demonstration for NO_X testing of:

4UF Furnaces F-4, F-5 and F-6 (vented through a common stack, identified as 224-04)

4UF Furnaces F-1, F-8A and F8B (vented through a common stack, identified as 224-01).

(b) Pursuant to SSM 089-32033-004, the Permittee shall perform PM, PM10, CO, and VOC testing of Heaters F-1, F-8A, F-8B, F-2, F-3, F-4, F-5, F-6, and F-7. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee's requirements with regards to the initial compliance demonstration for PM, PM10, CO, and VOC testing of Heaters F-1, F-8A, F-8B, F-2, F-3, F-4, F-5, F-6, and F-7.

(c) Pursuant to SSM 089-32033-00453, the Permittee shall perform NO_X testing of Heater F-7. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee's requirements with regards to the initial compliance demonstration for NO_X testing of Heater F-7.

(d) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures) and utilizing methods approved by the commissioner. Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.16.10 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in 4UF Heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A and F-8B. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to demonstrate compliance with Condition D.16.3(c), by no later than December 31, 2016 the Permittee shall install, operate, calibrate and maintain a NO_X CEMs on 4UF Heaters F-2 and F-3.

As specified by the Consent Decree entered in Civil No. 2:12-CV-00207 The Permittee shall install, certify, calibrate, maintain, and operate the NO_X CEMS in accordance with the provisions of 40 CFR § 60.13 that are applicable to CEMs (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B. Unless Appendix F requirements are specifically required by NSPS or state regulations, then in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct either a RAA or a RATA on each CEMS at least once every three (3) years. The Permittee shall conduct a Cylinder Gas Audit each Calendar Quarter during which a RAA or a RATA is not performed.

(c) The Total Sulfur Continuous Analyzer and NO_X continuous emission monitoring systems (CEMS) shall be calibrated, maintained, and operated for measuring total sulfur and NO_X in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment. The SO_2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO_2.

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 the compliance status with Conditions D.16.2, and D.16.6, 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 and to document the compliance status 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 Ja and to document the compliance status with Condition D.16.4, the Permittee shall maintain the records specified in Section F.3.

(d) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.16.5(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) In order to document the compliance status with Condition D.16.3, the Permittee shall maintain records of monthly firing rates and SO_2 emissions at F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, and F-8B.

(f) Pursuant to 326 IAC 3-5-6 and to document the compliance status 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.

(g) To document compliance with Condition D.16.5(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(h) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (d), (e) and (f) of this condition.

D.16.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Conditions D.16.2, and D.16.6, the Permittee shall submit a report to IDEM, OAQ not later than 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 Ja and to document the compliance status with Condition D.16.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section F.3.

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.16.5(a), the Permittee shall submit reports as specified in the LDAR plan.

(d) In order to document the compliance status with Condition D.16.3, the Permittee shall submit a quarterly summary of the monthly firing rates and SO_2 emissions at heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, and F-8B not later than thirty (30) days after the end of the quarter being reported.

(e) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.16.3 and D.16.10, the Permittee shall submit reports of excess SO_2 emissions at heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, and F-8B not later than 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

(f) To document compliance with Condition D.16.5(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(g) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (c), (d) and (e) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.17 EMISSIONS UNIT OPERATION CONDITIONS - Hydrogen Unit

Emissions Unit Description:

(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) The HU is connected to the DDU Flare (identified in Section D.35). This system flare is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns and depressuring equipment for maintenance.

(3) One (1) CO2 vent from the HU process. This vent has the potential to emit small amounts of methanol.

(4) Leaks from process equipment, including pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges and other connectors and heat exchange 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.17.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6, PM_{10} emissions from the HU (hydrogen unit) B-501 Process Heater shall not exceed 0.0075 lb/mmBTU and 2.729 lb/hr.

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 2-1.1-4] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4 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	NO_X (lb/mmBTU)	CO (lb/mmBTU)	VOC (lb/mmBTU)	PM_{10} (lb/mmBTU)
B-501	0.0675	0.02	0.0054	0.0075

(b) Pursuant to SSM 089-32033-00453, PM emissions from B-501 shall not exceed 0.0075 pounds per million BTU.

(c) After the completion of the WRMP project, the SO_2 emissions from B-501 shall not exceed 15.5 tons per 12 consecutive month period, with compliance determined at the end of each month.

(d) After the completion of the WRMP project, 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.

(e) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.17.6. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.17.4 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Supbart Ja]

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, Hydrogen Unit Heater B-501 shall be an affected facility for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for Heater B-501.

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 [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the Hydrogen Unit shall be an affected facility for purposes of 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at the Hydrogen Unit no later than one year from the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207.

(2) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.17.7 Operating Requirement

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and 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.17.8 Consent Decree (Civil No. 2:12-CV-00207) Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in B-501 shall not exceed 70 ppmvd total sulfur calculated as H_2S on a "12-month rolling average" basis.

Compliance Determination Requirements

D.17.9 Compliance Determination Requirements

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.

D.17.10 Performance Testing Requirements

(a) Pursuant to SSM 089-32033-00453 and as required in the Consent Decree entered in Civil No. 2:12-CV-00207, the Permittee shall conduct performance tests to measure emissions of NO_X from Heater B-501 once every five years. For the measurement of NO_X emissions, the Permittee shall comply with the performance test protocols established by EPA Method 7E in conjunction with either EPA Method 19 or EPA Methods 1, 2, 3 and 4, or an EPA-approved alternative test method.

Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee's requirements with regards to the initial compliance demonstration for NO_X testing of Heater B-501.

(b) Pursuant to SSM 089-32033-00453, the Permittee shall perform CO, PM, PM10, and VOC testing of Heater B-501. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee's requirements with regards to the initial compliance demonstration for CO, PM, PM10, and VOC testing of Heater B-501.

(c) Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures) and utilizing methods approved by the commissioner. Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.17.11 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in Heater B-501. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) In order to demonstrate compliance with Condition D.17.3(c), the Total Sulfur Continuous Analyzer for B-501 shall be calibrated, maintained, and operated for determining compliance with SO_2 limit for B-501 in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment. The SO_2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO_2.

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

D.17.12 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.17.13 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document the compliance status with Conditions D.17.2, and D.17.7, 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 and to document the compliance status 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 Ja and to document the compliance status with Condition D.17.4, the Permittee shall maintain the records specified in Section F.3.

(d) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.17.6(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) In order to document the compliance status with Condition D.17.3, the Permittee shall maintain records of monthly firing rate and SO_2 emissions at B-501.

(f) Pursuant to 326 IAC 3-5-6 and to document the compliance status with D.17.11, 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.

(g) To document compliance with Condition D.17.6(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(h) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (d), (e) and (f) of this condition.

D.17.14 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Conditions D.17.2, and D.17.7, the Permittee shall submit a report to IDEM, OAQ not later than 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 Ja and to document the compliance status with Condition D.17.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section F.3.

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.17.6(a), the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) In order to demonstrate document the compliance status with Condition D.17.3, the Permittee shall submit a quarterly summary of the monthly firing rate and SO_2 emissions at heater B-501 not later than thirty (30) days after the end of the quarter being reported.

(e) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.17.3 and D.17.11, the Permittee shall submit reports of excess SO_2 emissions at heater B-501 not later than 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

(f) To document compliance with Condition D.17.6(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(g) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (c), (d) and (e) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.18 EMISSIONS UNIT OPERATION CONDITIONS - Distillate Desulfurizer Unit

Emissions Unit Description:

(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 B-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 B-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, including pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges and other connectors and heat exchange systems.

(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 PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6, the Permittee shall not exceed the following PM_{10} emission limitations for the DDU Process Heaters:

Process Heater	PM_{10} Limit (lbs/mmBTU)	PM_{10} Limit (lbs/hour)
B-301	0.0075	1.106
B-302	0.0075	

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 B-301 and B-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 2-1.1-4] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-2 not applicable, the Permittee shall comply with the following:

(a) For heaters B-301 and B-302, upon issuance of Significant Permit Modification No. 089-25488-00453, the emissions shall not exceed the following emissions limits:

Heater ID	NO_X (lb/mmBTU)	CO (lb/mmBTU)	VOC (lb/mmBTU)	PM_{10} (lb/mmBTU)
B-301	0.035	0.04	0.0054	0.0075
B-302	0.030	0.04	0.0054	0.0075

(b) Pursuant to SSM 089-32033-00453, the Permittee shall comply with the following limits, following the completion of the WRMP project:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	SO_2 tons per 12 consecutive month period	PM (lb/mmBTU)
B-301	1,191.36 (combined)	6.6 (combined)	0.0075
B-302			0.0075

(c) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.18.6. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.18.4 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, DDU Heaters B-301 and B-302 shall be affected facilities for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for Heaters B-301 and B-302.

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 completion of the WRMP project, nitrogen Oxide (NO_X) emissions from the B-301 and B-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 B-301 and B-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 B-301 and B-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 B-301 and B-302 Process Heaters.

(c) Prior to completion of the WRMP project, the input of natural gas and natural gas equivalents to Process Heaters B-301 and B-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 [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the completion of modifications to the DDU authorized by SSM 089-25484-00453 or upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, whichever is sooner, the DDU shall be an affected facility for purposes of 40 CFR 60, Subpart GGGa, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the DDU no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.18.7 Operating Requirement

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and 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-301 and B-302 Process Heaters.

D.18.8 Consent Decree (Civil No. 2:12-CV-00207) Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in B-301 and B-302 shall not exceed 70 ppmvd total sulfur calculated as H_2S on a "12-month rolling average" basis.

Compliance Determination Requirements

D.18.9 Compilance Determination Requirements

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.

D.18.10 Performance Testing Requirements

Pursuant to SSM 089-32033-00453, the Permittee shall perform NO_X, PM, PM10, CO, and VOC testing of Heater B-301 and B-302 utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee's requirements with regards to the initial compliance demonstration for NO_X, PM, PM10, CO, and VOC testing of Heater B-301 and B-302. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.18.11 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in DDU Heaters B-301 and B-302. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) In order to demonstrate compliance with Conditions D.18.3(b) and D.18.8, the Total Sulfur Continuous Analyzer for B-301 and B-302 shall be calibrated, maintained, and operated for determining compliance with SO_2 emissions limits for B-301 and B-302 in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment. The SO_2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO_2.

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

D.18.12 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.18.13 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document the compliance status with Conditions D.18.2, and D.18.7, the Permittee shall maintain a daily record of the following for the B-301 and B-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 and to document the compliance status with Condition D.18.1, the Permittee shall maintain records for the B-301 and B-302 as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart Ja and to document the compliance status with Condition D.18.4, the Permittee shall maintain the records specified in Section F.3.

(d) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.18.6(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) In order to document the compliance status with Condition D.18.3, the Permittee shall maintain records of monthly firing rates and SO_2 emissions at B-301 and B-302.

(f) Pursuant to 326 IAC 3-5-6 and to document the compliance status with Condition D.18.11, 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.

(g) To document compliance with Condition D.18.6(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(h) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (d), (e), and (f) of this condition.

D.18.14 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Conditions D.18.2, and D.18.7, the Permittee shall submit a report to IDEM, OAQ not later than 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-301 and B-302 process heaters.

(b) Pursuant to 40 CFR 60, Subpart Ja and to document the compliance status with Condition D.18.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section F.3.

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.18.6(a), the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(d) In order to document the compliance status with Condition D.18.3, the Permittee shall submit a quarterly summary of the monthly firing rates and SO_2 emissions at heaters B-301 and B-302 not later than thirty (30) days after the end of the quarter being reported.

(e) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.18.3 and D.18.11, the Permittee shall submit reports of excess SO_2 at heaters B-301 and B-302 emissions not later than 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

(f) To document compliance with Condition D.18.6(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(g) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (c), (d), and (e) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.19 EMISSIONS UNIT OPERATION CONDITIONS - Cat Feed Hydrotreating Unit

Emissions Unit Description:

(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 CFHU is connected to the 4UF flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, 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, including pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges and other connectors and heat exchange 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.19.1 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6, the PM_{10} 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.19.2 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 2-1.1-4] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4 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	NO_X (lb/mmBTU)	CO (lb/mmBTU)	VOC (lb/mmBTU)	PM_{10} (lb/mmBTU)
F-801A	0.049	0.082	0.0054	0.0075
F-801B	0.049	0.082	0.0054	0.0075
F-801C	0.036	--	0.0054	0.0075

(b) Pursuant to SSM 089-32033-00453, the Permittee shall comply with the following limits following the completion of the WRMP project:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	SO_2 ton per 12 consecutive month period	PM (lb/mmBTU)	CO (lb/mmBTU)
F-801A	198.11	1.1	0.0075	--
F-801B	220.75	1.2	0.0075	--
F-801C	349.85	1.9	0.0075	0.082

(c) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.19.5. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.19.4 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, CFHU Heaters F-801A, F-801B and F-801C shall be affected facilities for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for CFHU Heaters F-801A, F-801B and F-801C.

D.19.5 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the CFHU shall be an affected facility for purposes of 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the CFHU no later than one year from the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The CFHU shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.19.6 Operating Requirement

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and pursuant to Permit SSM 089-14630-00003, issued on November 30, 2001, "fuel oil" shall not be used as fuel for the CFHU Heaters F-801A, F-801B and F-801C.

D.19.7 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.19.8 Consent Decree (Civil No. 2:12-CV-00207) Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in F-801A, F-801B and F-801C shall not exceed 70 ppmvd total sulfur calculated as H_2S on a "12-month rolling average" basis.

Compliance Determination Requirements

D.19.9 Compliance Determination Requirements

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.

D.19.10 Performance Testing Requirements

Pursuant to SSM 089-32033-0045, the Permittee shall perform NO_X, PM, PM10, CO, and VOC testing of Heater F-801A, F-801B and F-801C utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee's requirements with regards to the initial compliance demonstration for NO_X, PM, PM10, CO, and VOC testing of Heater F-801A, F-801B and F-801C. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.19.11 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in Heaters F-801A, F-801B and F-801C. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) In order to demonstrate compliance with Conditions D.19.3(b) and D.19.8, the Total Sulfur Continuous Analyzer for F-801A, F-801B, and F-801C shall be calibrated, maintained, and operated for determining compliance with SO_2 emissions limits for F-801A, F-801B, and F-801C in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment. The SO_2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO_2.

Compliance Monitoring Requirements

D.19.12 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.19.13 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document the compliance status with Conditions D.19.2, and D.19.6, 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 and to document the compliance status with Condition D.19.1, the Permittee shall maintain records for the F-801A/B and F-801 C process heater as specified in the Continuous Compliance Plan.

(c) Pursuant to 40 CFR 60, Subpart Ja and to document the compliance status with Condition D.19.4, the Permittee shall maintain the records specified in Section F.3.

(d) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.19.5(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(e) In order to document the compliance status 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 SO_2 from F-801A, F-801B, and F-801C.

(f) Pursuant to 326 IAC 3-5-6 and to document the compliance status with Condition D.19.11, 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.

(g) To document compliance with Condition D.19.5(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(h) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (d), (e) and (f) of this condition.

D.19.14 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Conditions D.19.2, and D.19.6, the Permittee shall submit a report to IDEM, OAQ not later than 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 Ja and to document the compliance status with Conditions D.19.4, the Permittee shall submit the reports as specified in Section F.3.

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.19.5(a), the Permittee shall submit reports as specified in the LDAR plan.

(d) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.19.3 and D.19.11 the Permittee shall submit reports of excess SO_2 emissions at heaters F-801A, F-801B, and F-801C not later than 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

(e) In order to document the compliance status with Condition D.19.3, the Permittee shall submit a quarterly summary of the monthly firing rates at F-801A, F-801B, and F-801C, and monthly emissions of SO_2 from F-801A, F-801B, and F-801C not later than thirty (30) days after the end of the quarter being reported.

(f) To document compliance with Condition D.19.5(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(g) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (c), (d) and (e) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.20 EMISSIONS UNIT OPERATION CONDITIONS - Catalytic Refining Unit

Emissions Unit Description:

(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 and associated flare gas recovery system FGRS4. This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance.

(3) Miscellaneous process vent emissions which are routed to the UIU flare and associated flare gas recovery system FGRS4 (identified in Section D.35).

(4) Leaks from process equipment, including pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation and heat exchange 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 PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6, the Permittee must comply with the following PM_{10} emission limitations for the CRU (also known as unit ID 201) feed preheaters:

Process Heater	PM_{10} Limit (lbs/mmBTU)	PM_{10} Limit (lbs/hour)
F-101	0.0075	0.536
F-102A	0.0075	0.447

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 2-1.1-4] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4 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	NO_X (lb/mmBTU)	CO (lb/mmBTU)	VOC (lb/mmBTU)	PM_{10} (lb/mmBTU)
F101	0.08	0.082	0.0054	0.0075
F-102A	0.08	0.082	0.0054	0.0075

(b) Pursuant to SSM 089-32033-00453, the Permittee shall comply with the following limits, following completion of the WRMP project:

Unit ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	SO_2 tons per 12 consecutive month period	PM (lb/mmBTU)
F-101	595.68	3.3	0.0075
F-102A	394.20	2.2	0.0075

(c) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.20.5. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.20.4 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, CRU Heaters F-101 and F-102A shall be affected facilities for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for Heaters F-101 and F-102A.

D.20.5 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the CRU shall be an affected facility for purposes of 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the CRU no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The CRU shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.20.6 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.

D.20.7 Operating Requirement

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and 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.

D.20.8 Consent Decree (Civil No. 2:12-CV-00207) Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in F-101 and F-102A shall not exceed 70 ppmvd total sulfur calculated as H_2S on a "12-month rolling average" basis.

Compliance Determination Requirements

D.20.9 Compliance Determination Requirements

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.

D.20.10 Performance Testing Requirements

Pursuant to SSM 089-32033-00453, the Permittee shall perform NO_X, PM, PM10, CO, and VOC testing of Heater F-101 and F-102A utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee's requirements with regards to the initial compliance demonstration for NO_X, PM, PM10, CO, and VOC testing of Heater F-101 and F-102A. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.20.11 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in Heaters F-101 and F-102A. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) In order to demonstrate compliance with Condition D.20.3(b) and D.20.8, the Total Sulfur Continuous Analyzer for F-101 and F-102A shall be calibrated, maintained, and operated for determining compliance with SO_2 emissions limits for F-101 and F-102A in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment. The SO_2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO_2.

Compliance Monitoring Requirements

D.20.12 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.20.13 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document the compliance status with Conditions D.20.2, and D.20.7, 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 Ja and to document the compliance status with Condition D.20.4, the Permittee shall maintain the records as specified in Section F.3.

(c) Pursuant to 326 IAC 8-4-8, and to document the compliance status with Condition D.20.5(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) Pursuant to 326 IAC 6.8-8-7 and to document the compliance status 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.

(e) In order to document the compliance status with Condition D.20.3, the Permittee shall maintain records of monthly firing rates and SO_2 emissions at F-101 and F-102A.

(f) Pursuant to 326 IAC 3-5-6 and to document the compliance status with Condition D.20.11, 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.

(g) To document compliance with Condition D20.5(d), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(h) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (c), (d), (e) and (f) of this condition.

D.20.14 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Conditions D.20.2 and D.20.7, the Permittee shall submit a report to IDEM, OAQ not later than 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 Ja and to document the compliance status with Condition D.20.4, the Permittee shall submit to IDEM, OAQ the reports specified in Section F.3.

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.20.5(a), the Permittee shall submit reports as specified in the LDAR plan.

(d) In order to document the compliance status with Condition D.20.3, the Permittee shall submit a quarterly summary of the monthly firing rates and SO_2 emissions at heaters F-101 and F-102A not later than thirty (30) days after the end of the quarter being reported.

(e) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.20.3 and D.20.11, the Permittee shall submit reports of excess SO_2 emissions at heaters F-101 and F-102A not later than 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

(f) To document compliance with Condition D.20.5(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(g) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (c), (d) and (e) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

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

Emissions Unit Description:

(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. Stack S/V 230-01 has continuous emissions monitors (CEMS) for NO_X, SO_2, CO and O_2.

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

(3) FCU 500 is connected to the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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).

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

(6) 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 a flare or flare gas recovery system.

(7) 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 WRMP project related contemporaneous emissions increases.

(8) Miscellaneous process vent emissions, which are routed to the VRU flare and associated flare gas recovery system FGRS3 (identified in Section D.35).

(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 PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6, PM_{10} emissions from FCU 500 shall not exceed 1.22 pounds per thousand pounds of coke burned and 73.2 pounds per hour.

D.21.2 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 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 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for FCU 500 after the completion of the WRMP project:

(a) The emissions of NO_X shall not exceed 278.7 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) By December 31, 2012, the emissions of SO_2 shall not exceed 122 tons per 12 consecutive month period, with compliance determined at the end of each month.

(d) The emissions of CO shall not exceed 179.5 tons per 12 consecutive month period, with compliance determined at the end of each month.

(e) 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.

(f) 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.

(g) 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 a flare or flare gas recovery system.

(h) Emission Limits for PM_{10} and PM_{TOTAL}

   (a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than December 31, 2013, the emissions of $PM_{\mathbf{10}}$ from FCU 500 shall not exceed 0.9 pound per 1,000 pounds of coke burned as determined by the EPA methods as specified in Condition D.21.10(b) - Test Methods for PM10 and PM_{TOTAL} Emissions.

   (b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than December 31, 2013, the emissions of $PM_{\mathbf{TOTAL}}$ from FCU 500 shall not exceed 1.2 pounds per 1,000 pounds of coke burned as determined by the EPA methods as specified in Condition D.21.10(b) - Test Methods for PM10 and PM_{TOTAL} Emissions.

(i) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.21.4. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the FCU 500 throughput limits and the NO_X, VOC, SO_2, 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 NO_X, VOC, CO, SO_2, PM and PM_{10} for the WRMP project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.21.4 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the FCU 500 is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at FCU 500 no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) FCU 500 shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

(4) The two consecutive months of monitoring that the Permittee previously conducted for purposes of 40 CFR 60, Subpart GGGa at FCU 500 satisfies the requirement to conduct monitoring of those components for two consecutive months following the initial applicability of 40 CFR 60, Subpart GGGa.

D.21.5 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the FCU 500 shall be an affected facility as that term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for NO_X, PM, and CO applicable to fluid catalytic cracking units. Entry of the Consent Decree in Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Civil No. 2:12-CV-00207 for FCU 500 shall satisfy the notice requirements of 40 CFR 60.7(a) and the initial performance test requirement of 40 CFR 60.8(a).

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the FCU 500 shall be an affected facility as that term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 applicable to fluid catalytic cracking units. Entry of the Consent Decree in Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Civil No. 2:12-CV-00207 for FCU 500 shall satisfy the notice requirements of 40 CFR 60.7(a) and the initial performance test requirement of 40 CFR 60.8(a).

D.21.6 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.21.7 Consent Decree (Civil No. 2:12-CV-00207) Requirements

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the emissions of NO_X from FCU 500 shall not exceed 40 ppmvd @ 0% O2 based on a "365-day rolling average" and 80 ppmvd NO_X @ 0% based on a "7-day rolling average".

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than ninety (90) days after "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the emissions of NO_X from FCU 500 shall not exceed 80 ppmvd @ 0% O_2 based on a "7-day rolling average".

(c) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than ninety (90) days after the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the emissions of NO_X from FCU 500 shall not exceed 35 ppmvd @ 0% O2 based on a "365-day rolling average".

(d) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree in Civil No. 2:12-CV-00207, NO_X emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the "7-day rolling average" NO_X emission limits required by the Consent Decree in Civil No. 2:12-CV-00207 at FCU 500, provided that during such periods the Permittee implements good air pollution control practices as required by 40 CFR 60.11(d) to minimize NO_X emissions at FCU 500.

As specified by the Consent Decree in Civil No. 2:12-CV-00207, NO_X emissions during periods of Startup, Shutdown, or Malfunction shall be used in determining compliance with the “365-day rolling average” NO_X emission limits required by the Consent Decree in Civil No. 2:12-CV-00207 at FCU 500.

(e) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the emissions of SO_2 from FCU 500 shall not exceed 25 ppmvd @ 0% O2 based on a "365-day rolling average" and 50 ppmvd @ 0% O2 based on a "7-day rolling average".

(f) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than December 31, 2012 the emissions of SO_2 from FCU 500 shall not exceed 50 ppmvd @ 0% O2 based on a "7-day rolling average".

(g) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than December 31, 2012, the emissions of SO_2 from FCU 500 shall not exceed 10 ppmvd @ 0% O2 based on a "365-day rolling average".

(h) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree in Civil No. 2:12-CV-00207, SO_2 emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the "7-day rolling average" SO_2 emission limits at FCU 500, provided that during such periods the Permittee implements good air pollution control practices as required by 40 CFR 60.11(d) to minimize SO_2 emissions at FCU 500.

As specified by the Consent Decree in Civil No. 2:12-CV-00207, SO_2 emissions during periods of Startup, Shutdown, or Malfunction shall be used in determining compliance with the “365-day rolling average” SO_2 emission limits required by the Consent Decree in Civil No. 2:12-CV-00207 at FCU500.

(i) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the emissions of CO from FCU 500 shall not exceed 500 ppmvd on a 1-hour average basis corrected to 0% O2.

As required by the Consent Decree in Civil No. 2:12-CV-00207, CO emissions during periods of Startup, Shutdown or Malfunction shall not be used in determining compliance with the 1-hour 500 ppmv emission limit, provided that during such periods the Permittee implements good air pollution control practices to minimize CO emissions from FCU 500.

(j) FCU 500 VOC Emissions
Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than December 31, 2013, the emissions of VOC from FCU 500 shall not exceed 3.3 pounds per 1000 barrels fresh feed.

D.21.8 Operating Requirements

(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) In order to demonstrate compliance with Condition D.21.3(g), after the completion of the WRMP project:

The pressure relief discharges that were routed to the FCU 500 blowdown stack shall be routed to a flare or flare gas recovery system. The flare must be operated with a flame present at all times that FCU 500 is in operation.

Compliance Determination Requirements

D.21.9 Compliance Determination Requirements

(a) Pursuant to SSM 089-32033-00453, in order to demonstrate compliance with Condition D.21.3, the emissions of NO_X, SO_2 and CO shall be calculated as the sum of the quantity in tons of the pollutant for the most recent complete calendar month and the previous 11 calendar months. Each month shall be calculated as follows:

$$\text{Emissions (ton/mo)} = \sum^{n} \left[\{(C_A \times \text{MWpollutant})/1{,}000{,}000\} \times \{(\text{Qstack}/V_{\mathbf{m}}) \times (60\ \text{min/hr}) \times (1\ \text{ton} / 2{,}000\ \text{lbs})\}\right]_i$$

Where:

n = Hours in the month
Qstack = Actual hourly average volumetric flow rate of flue gas from the FCU stack, dscf/min; calculated from process data or measured by stack flow meter (at 68 °F)
C_A = Actual hourly average pollutant concentration (ppmv) dry basis;
V_m = 385.3 dscf of gas per lb-mol at standard conditions (68 °F)

Where the calculated Qstack = Qr + Qesp

Where:

Qr = Volumetric flow rate of exhaust gas from catalyst regenerator before adding air or gas streams, dscf/min; (at 68 °F)
Qesp = Volumetric flow rate of penthouse purge air to ESP, dscf/min; (at °F)

$$Q_r = [79 \times Q_{air} + (100\text{-}\%O_{xy}) \times Q_{oxy}] / [100 - \%CO_2 - \%CO - \%O_2]$$

Where:

79 = Default concentration of nitrogen and argon in dry air, percent by volume (dry basis);
Qair = Volumetric flow rate of dry air to regenerator, dscf/min; (at 68 °F)
%Oxy = Oxygen concentration in oxygen-enriched stream, percent by volume (dry basis);
Qoxy = Volumetric flow rate of oxygen-enriched air stream to regenerator, dscf/min; (at 68 °F)
%CO2 = Carbon dioxide concentration in regenerator exhaust, percent by volume (dry basis);
%CO = Carbon monoxide concentration in regenerator exhaust, percent by volume (dry basis);
%O2 = Oxygen concentration in regenerator exhaust, percent by volume (dry basis);

(b) Pursuant to SSM 089-32033-0045, in order to demonstrate compliance with Condition D.21.3, the coke burned shall be calculated as the sum of the quantity in lbs of coke burned for the most recent complete calendar month and the previous 11 calendar months. Each month shall be calculated as follows:

$$R_{c(month)}\ \text{(lbs/month)} = \sum^{n} [K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times [(\%CO/2) + \%CO_2 + \%O_2] + K_3 Q_{oxy} \times (\%O_{xy})]_i$$

Where:

n = Hours in the month
$R_{c(month)}$ = Coke burned, (lbs/month);
Q_r = Volumetric flow rate of exhaust gas from catalyst regenerator before adding air or gas streams boiler, dscm/min (dscf/min); (at 68 °F)
Q_a = Volumetric flow rate of air to catalytic cracking unit catalyst regenerator, as determined from instruments in the catalytic cracking unit control room, dscf/min; (at 68 °F)
$\%CO_2$ = 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, 0.0186 (lb-min)/(hr-dscf-%));
K_2 = Material balance and conversion factor, (0.1303 (lb-min)/(hr-dscf));
K_3 = Material balance and conversion factor,(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,(dscf/min); and
$\%O_{xy}$ = Oxygen concentration in oxygen-enriched air stream, percent by volume (dry basis)

(c) Demonstrating Compliance with FCU VOC Emission Limits

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, emissions of VOC from FCU 500 to demonstrate compliance with Condition D.21.7 - FCU 500 VOC Emissions shall be calculated as follows:

$$E = \left(\frac{C \times Q \times MW \times 60}{V_m} \right) \times \left(\frac{1000}{F} \right)$$

$$C = C_{total} - C_{methane} - C_{ethane}$$

Where:

E = FCU VOC Emissions in lb/ 1000 bbl feed
C = concentration of non-methane and non-ethane organic carbon as carbon in volume fraction
Ctotal = concentration of total organic carbon in volume fraction, as carbon, as measured by EPA Method 25a
Cmethane = concentration of methane in volume fraction, as carbon, as measured by EPA Method 18
Cethane = concentration of ethane in volume fraction, as carbon, as measured by EPA Method 18
MW = molecular weight of carbon = 12.01 lb/lb-mole
Q = FCU stack flow in dry standard cubic feet per minute as measured by EPA Method (s) 1-4
1000 = conversion factor to put emissions on a per 1000 bbl feed
Vm = 385.3 dscf of gas per lb-mol at standard conditions (68 °F)
F = FCU feed rate in bbl/hour, averaged over period of source test
60 = conversion factor for 60 minutes per hour

(d) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, the Permittee shall:

(1) No later than 180 Days after the "Date of Entry" of the Consent Decree entered in Civil No. 2:12-CV-00207, and on a semi-annual basis thereafter, the Permittee shall conduct a performance test on FCU 500 pursuant to 40 .F.R. §§ 60.8 and 60.104a. Upon demonstrating through at least four (4) semi-annual tests that the PM limit in 40 C.F.R. § 60.102a(b)(1) is not being exceeded, the Permittee may reduce the required testing frequency to an annual basis. The Permittee shall provide notice to EPA no later than 30 Days in advance of the performance testing to be conducted pursuant to this paragraph, and shall provide the results of such testing upon request by EPA.

(2) In addition to the performance testing required by this paragraph, the Permittee may conduct testing to identify any parameters that may need to be maintained to assure compliance with the PM limits during testing. The Permittee shall provide EPA with notice no later than 30 Days in advance of testing to identify parameters pursuant to this paragraph, and shall provide the results of such testing upon request by EPA.

(e) Demonstrating Compliance with PM_{10} and PM_{TOTAL} Emission Limits

(1) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, compliance with the PM_{10} and PM_{TOTAL} emission limits in Condition D 21.3 - Emission Limits for PM_{10} and PM_{TOTAL} shall be based on the emission rate computed from the most recent performance test completed pursuant to Condition D.21.10 - FCU PM_{10} and PM_{Total} Performance Testing Requirements.

(2) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, the Permittee shall maintain compliance with the PM operating limits established under 40 C.F.R. § 60.102a(c)(1) during its demonstration of compliance with the PM_{10} and PM_{TOTAL} emission limits in Condition D.21.3 - Emission Limits for PM_{10} and PM_{TOTAL}.

(3) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207 , for the purposes of this paragraph, the Permittee may use Method 201A in lieu of Method 5 to determine PM_{TOTAL} emissions, provided that the Permittee follows the procedures in Method 201A for the collection and analysis of PM greater than 10 microns.

D.21.10 FCU PM_{10} and PM_{TOTAL} Performance Testing Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than 180 days after the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the Permittee shall implement a performance testing protocol in accordance with (a) through (e) as provided as follows:

Testing Frequency

(a) The Permittee shall conduct performance tests to measure emissions of PM_{10} and PM_{TOTAL} from FCU 500 on at least a semi-annual basis, with each semi-annual performance test being no sooner than four (4) calendar months from the date of completion of the previous semi-annual test. This shall not preclude the Permittee from conducting additional performance tests which are more frequent.

(1) Upon demonstrating, through at least four (4) valid, consecutive semi-annual tests conducted after December 31, 2013 that (i) the PM_{10} and PM_{TOTAL} limits (Condition D 21.3 - Emission Limits for PM_{10} and PM_{TOTAL}) are not being exceeded, (ii) the average of all four valid semi-annual tests is not more than 80% of the PM_{10} and PM_{TOTAL} limits and (iii) the average result from any valid semi-annual test is not greater than 90% of the PM_{10} and PM_{TOTAL} limits, the Permittee may reduce the frequency of performance testing to an annual basis.

(2) The Permittee may request EPA approval to reduce the frequency of such testing in other circumstances. EPA has sole discretion to approve or disapprove the Permittee's request, which shall not be subject to Dispute Resolution. In the event that a subsequent annual test indicates an exceedance of a PM_{10} or PM_{TOTAL} limit, EPA may elect to reinstate the requirement for semi-annual testing. EPA's decision to reinstate semi-annual testing shall not be subject to Dispute Resolution.

Test Methods for PM_{10} and PM_{TOTAL} Emissions

(b) The Permittee shall measure PM_{10} emissions using EPA Methods 201A and 202. The Permittee may use EPA Method 5 in lieu of EPA Method 201A for purposes of demonstrating compliance with the PM_{10} emission limit (Condition D.21.3 - Emission Limits for PM_{10} and PM_{TOTAL}) provided that all PM measured by EPA Method 5 is considered as PM_{10}.

The Permittee shall measure PM_{TOTAL} emissions using EPA Methods 5 and 202. The Permittee may use EPA Method 201A in lieu of EPA Method 5 for purposes of demonstrating compliance with the PM_{TOTAL} emission limit provided that the Permittee also follows the procedures in EPA Method 201A for the collection and analysis of PM greater than 10 microns.

Test Run Duration

(c) Each performance test shall be comprised of at least three (3) valid two-hour stack test runs. The Permittee shall discard any invalid test runs, such as those that are compromised because of sample contamination. If a test run is discarded, it shall be replaced with an additional valid test run. The Permittee shall report the results of the discarded test runs and shall provide all information necessary to document why the test run was not valid.

Valid Performance Tests

(d) A PM_{10} and PM_{TOTAL} test shall not be considered a valid test, and the Permittee will not have met the requirement of this condition to test, unless each of the following conditions is met:

(1) The average FCU 500 coke burn rate for all runs used in determining compliance with the PM_{10} and PM_{TOTAL} emission limits must not be less than actual average FCU 500 coke burn rate over the time period since the previous performance test;

(2) The average SO_2 concentration for all runs used in determining compliance with the PM_{10} and PM_{TOTAL} emission limits must not be greater than 10 ppmvd @ 0% O_2; and

(3) The average total ammonia injection rate for all runs used in determining compliance with the PM_{10} and PM_{TOTAL} emission limits must not be less than average total ammonia injection rate over the time period since the previous performance test.

(4) Throughout the performance test, the Permittee shall target the average ESP total primary power since the last stack test. The average ESP total primary power for all the runs used in determining compliance with the PM_{10} and PM_{TOTAL} emission limits must not be greater than 120% of the average ESP total primary power since the last stack test.

Additional Parametric Monitoring During the Tests

(e) The Permittee shall monitor or calculate and record SO_2 concentration, NO_X concentration, catalyst additive rates, ammonia addition prior to ESP, ammonia slip, the FCU 500 coke burn-off rate, regenerator overhead temperatures, and FCU 500 feed rate for each test run. The Permittee shall reduce this monitoring data to an average that matches the time period of each test run.

Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures) and utilizing methods approved by the commissioner. Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.21.11 FCU VOC Performance Testing Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, and in order to demonstrate compliance with the emission limit in D.21.7 - FCU 500 VOC Emissions, by no later than December 31, 2013, and annually thereafter, the Permittee shall conduct performance tests to measure emissions of VOC from FCU 500, except as provided as follows:

(a) If a stack test for FCU 500 demonstrates that VOC emissions from FCU 500 are less than half of the applicable VOC emissions limit in Condition D.21.7 - FCU 500 VOC Emissions, the Permittee may thereafter elect to conduct stack tests at least once every three (3) years at FCU 500 in lieu of annual stack testing.

(b) If, after the Permittee exercises the option to conduct stack testing at least once every three (3) years pursuant to this paragraph, and a stack test thereafter demonstrates an exceedance of the applicable VOC emissions limit in Condition D.21.7 - FCU 500 VOC Emissions, the Permittee shall resume annual stack testing for FCU 500.

Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures) and utilizing methods approved by the commissioner. Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.21.12 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the Permittee shall use NO_X, SO_2, CO and O_2 CEMS to demonstrate compliance with the NO_X, SO_2 and CO limits in Condition D.21.7. The Permittee shall install, certify, calibrate, maintain and operate the NO_X, SO_2, CO, and O_2 CEMS for FCU 500 in accordance with the provisions of 40 CFR 60.13 that are applicable to CEMS (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B. The Permittee must conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed.

(b) The NO_X, CO, SO_2, and O_2 continuous emission monitoring systems (CEMS) for FCU 500 shall be calibrated, maintained, and operated for measuring NO_X, CO, and SO_2 in accordance with the applicable requirements in Section C - Maintenance of Continuous

Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements

D.21.13 Continuous Monitoring [326 IAC 3-5-1(e)][326 IAC 6.8-8]

(a) Condition C - Maintenance of Continuous Monitoring Equipment contains the Permittee's obligation with regard to the COM monitoring required by this condition.

(b) Pursuant to 326 IAC 3-5 and 326 IAC 6.8-8-5(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), the Permittee shall continuously monitor coke burn off rate, in pounds per hour, as specified in the Continuous Compliance Plan (CCP).

D.21.14 Supplemental FCU PM Monitoring Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the Permittee shall monitor and record the daily values for the following operating parameters:

(a) The feed rate, in barrels per day, for FCU 500;

(b) The average rate, in pounds per hour, at which SO_2-reducing catalyst additive is added to FCU 500; and

(c) The average amount of ammonia in pounds per hour injected into the FCU 500 ESP.

D.21.15 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.

D.21.16 Compliance Assurance Monitoring (CAM) [40 CFR Part 64]

Pursuant to 40 CFR Part 64, the Permittee shall comply with the following Compliance Assurance Monitoring requirements for the electrostatic precipitator controlling FCU 500:

Monitoring Approach for PM_{10} and PM_{Total} Emissions From FCU 500			
Parameter	**Indicator No. 1**	**Indicator No. 2**	**Indicator No. 3**
I. Indicator	Proper Operation of Electrostatic Precipitator (ESP)	Particulate loading at the Electrostatic Precipitator (ESP) inlet	Inspection and Maintenance
Measurement Approach	Average ESP total primary power and secondary current.	Average exhaust coke burn-off rate	Inspections and Maintenance of the ESP
II. Indicator Range	An excursion is defined as a 3-hour rolling average ESP total primary power or secondary current falling below the level	An excursion is defined as a daily average exhaust coke burn-off rate exceeding the level established during	An excursion is defined as not following the inspection schedule and procedures specified in the Continuous Compliance Plan (CCP).

Monitoring Approach for PM_{10} and PM_{Total} Emissions From FCU 500			
Parameter	**Indicator No. 1**	**Indicator No. 2**	**Indicator No. 3**
	established in the most recent performance test conducted pursuant to 40 CFR §60.104a.	the during the most recent performance test conducted pursuant to 40 CFR §60.104a.	
III. Performance Criteria	--	--	--
A. Data Representativeness	Continuous Parameter Monitoring System (CPMS) requirements in 40 CFR 60.105a(b)(1)(i) and (iii).	Continuous Parameter Monitoring System (CPMS) requirements in 40 CFR 60.105a(b)(1)(iii) and (iv).	Recording, inspection, and maintenance procedures as prescribed in Condition D.21.13.
B. Verification of Operational Status	Data being reported to DCS on a continuous basis.	Data being reported to DCS on a continuous basis.	Records kept as prescribed in Condition D.21.13.
C. QA/QC Practices and Criteria	Periodic inspection and maintenance of the ESP and monitoring systems per CCP.	N/A	Update the CCP as needed.
D. Monitoring Frequency	Measure and record hourly average ESP total primary power and secondary voltage to the entire system per 40 CFR 105a(b)(1)(i).	Determine and record the average coke burn-off rate and hours of operation for FCU 500 per 40 CFR 105a(b)(1)(iv).	As prescribed in the CCP which meets the requirements of 326 IAC 6.8-8-7.
IV. Data Collection Procedure	Continuous Parameter Monitoring System meeting the requirements of 40 CFR 60.105a(b)(1)(i) and (iii).	Continuous Parameter Monitoring System meeting the requirements of 40 CFR 60.105a(b)(1)(iii) and (iv).	Per the methods prescribed in the CCP which meets the requirements of 326 IAC 6.8-8-7.
Averaging Period	3-hour average rolled hourly.	Daily average	N/A

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

D.21.17 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(B) and to document the compliance status 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 the compliance status with Conditions D.21.3, D.21.6, D.21.12, D.21.13, and D.21.16, 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 the compliance status with Condition D.21.4(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) Pursuant to SPM 089-15202-00003, issued on April 24, 2002, and SPM 089-18588-00453, issued July 15, 2004, and to document the compliance status with Condition D.21.8, the Permittee shall maintain records of 1-hour average CO emissions.

(e) In order to document the compliance status 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.

(f) In order to document the compliance status with Condition D.21.3, the Permittee shall maintain records of monthly emissions of SO_2, NO_X, and CO from FCU 500.

(g) To document compliance with Condition D.21.4(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(h) To document compliance with Condition D.21.5, the Permittee shall keep records pursuant to 40 CFR 60, Subpart Ja, as specified in Section F.3.

(i) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (c), (d), (e), and (f) of this condition.

D.21.18 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status 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 not later than thirty (30) days after the end of each calendar quarter.

(b) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.21.6 and D.21.13, the Permittee shall submit reports of excess opacity emissions not later than 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 the compliance status with Condition D.21.4(a), the Permittee shall submit reports as specified in the LDAR plan.

(e) In order to document the compliance status with Condition D.21.3, the Permittee shall submit quarterly reports for the fresh feed used and coke burned at FCU 500 not later than thirty (30) days of the end of each quarter.

(f) In order to document the compliance status with Condition D.21.3, the Permittee shall submit quarterly reports of monthly emissions of SO_2, NO_X, and CO from FCU 500 not later than thirty (30) days of the end of each quarter.

(g) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.21.3 and D.21.13, the Permittee shall submit reports of excess SO_2, NO_X, and CO emissions at FCU 500 not later than 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) To document compliance with Condition D.21.4(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(i) To document compliance with Condition D.21.5, the Permittee shall submit reports pursuant to 40 CFR 60, Subpart Ja, as specified in Section F.3.

(j) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (b), (c), (d), (e), (f), and (g) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

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

Emissions Unit Description:

(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. Stack S/V has continuous emissions monitors (CEMS) for NO_X, SO_2, CO and O_2.

(2) Two catalyst storage bins, one each for equilibrium and fresh catalyst, controlled by one (1) baghouse. (Spent catalyst is stored in Bin F-52, which is associated with FCU 500.)

(3) FCU 600 is connected to the FCU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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-3D and J-3E).

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

(6) 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 a flare or flare gas recovery system.

(7) 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 WRMP project related contemporaneous 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]

Pursuant to 326 IAC 6.8-2-6, PM_{10} emissions from FCU 600 shall not exceed 1.10 pounds per thousand pounds of coke burned and 55.0 pounds per hour.

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 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for FCU 600:

After the completion of the WRMP project, the Permittee shall comply with the following:

(a) The emissions of NO_X shall not exceed 90.0 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) By September 1, 2013, the emissions of SO_2 shall not exceed 78 tons per 12 consecutive month period, with compliance determined at the end of each month.

(d) The emissions of CO shall not exceed 112.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(e) 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.

(f) 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.

(g) The FCU 600 blowdown stack shall be permanently shutdown and the pressure relief discharges that were routed to the blowdown stack will be routed to a flare or flare gas recovery system.

(h) Emission Limits for PM_{10} and PM_{TOTAL}

    (a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than December 31, 2013, the emissions of $PM_{\mathbf{10}}$ from FCU 600 shall not exceed 0.7 pound per 1,000 pounds of coke burned as determined by the EPA methods as specified in Condition D.22.10(b) - Test Methods for PM_{10} and PM_{TOTAL} Emissions.

    (b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than December 31, 2013, the emissions of $PM_{\mathbf{TOTAL}}$ from FCU 600 shall not exceed 1.2 pounds per 1,000 pounds of coke burned as determined by the EPA methods as specified in Condition D.22.10(b) - Test Methods for PM_{10} and PM_{TOTAL} Emissions.

(i) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.22.4. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the FCU 600 throughput limits and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.22.4 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207 , the FCU 600 is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each valve, pump, pressure relief device, sampling connection system, open-ended valve or line, and flange or other connector in VOC service at FCU 600 no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) FCU 600 shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.22.5 Operating Requirements

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) In order to demonstrate compliance with Condition D.22.3(g), after the completion of the WRMP project:

The pressure relief discharges that were routed to the FCU 600 blowdown stack shall be routed to a flare or flare gas recovery system. The flare must be operated with a flame present at all times that FCU 600 is in operation.

D.22.6 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.22.7 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the FCU 600 shall be an affected facility as that term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for NOx, PM, and CO applicable to fluid catalytic cracking units. Entry of the Consent Decree in Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Civil No. 2:12-CV-00207 for FCU 600 shall satisfy the notice requirements of 40 CFR 60.7(a) and the initial performance test requirement of 40 CFR 60.8(a).

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than September 1, 2013, the FCU 600 shall be an affected facility for SO_2 as that term is used in 40 CFR 60, Subparts A and Ja. By no later than September 1, 2013, FCU 600 shall be subject to and comply with the requirements of 40 CFR 60, Subparts A and Ja, for SO_2 applicable to FCCUs. Entry of the Consent Decree in Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Civil No. 2:12-CV-00207 for FCU 600 shall satisfy the notice requirements of 40 CFR 60.7(a) and the initial performance test requirement of 40 CFR 60.8(a).

D.22.8 Consent Decree (Civil No. 2:12-CV-00207) Requirements

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the emissions of NO_X from FCU 600 shall not exceed 20 ppmvd @ 0% O2 based on a "365-day rolling average" and 40 ppmvd @ 0% O2 based on "7-day rolling average".

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than ninety (90) days after the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the emissions of NO_X from FCU 600 shall not exceed 40 ppmvd @ 0% O2 based on a "7-day rolling average".

(c) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than ninety (90) days after the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the emissions of NO_X from FCU 600 shall not exceed 10 ppmvd @ 0% O2 based on a "365-day rolling average".

(d) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree in Civil No. 2:12-CV-00207, NO_X emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the "7-day rolling average" NO_X emission limits required by the Consent Decree in Civil No. 2:12-CV-00207 at FCU 600, provided that during such periods the Permittee implements good air pollution control practices as required by 40 CFR 60.11(d) to minimize NO_X emissions at FCU 600.

As specified by the Consent Decree in Civil No. 2:12-CV-00207, NO_X emissions during periods of Startup, Shutdown, or Malfunction shall be used in determining compliance with the “365-day rolling average” NO_X emission limits required by the Consent Decree in Civil No. 2:12-CV-00207 at FCU 600.

(e) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the emissions of SO_2 from FCU 600 shall not exceed 50 ppmvd @ 0% O2 based on a "365-day rolling average" and 125 ppmvd @ 0% O2 based on a "7-day rolling average".

(f) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than September 1, 2013, pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the emissions of SO_2 from FCU 600 shall not exceed 10 ppmvd @ 0% O2 based on a "365-day rolling average".

(g) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than September 1, 2013, pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the emissions of SO_2 from FCU 600 shall not exceed 50 ppmvd @ 0% O2 based on a "7-day rolling average".

(h) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree in Civil No. 2:12-CV-00207, SO_2 emissions during periods of Startup, Shutdown, or Malfunction shall not be used in determining compliance with the "7-day rolling average" SO_2 emission limits required by the Consent Decree in Civil No. 2:12-CV-00207 at FCU 600, provided that during such periods the Permittee implements good air pollution control practices as required by 40 CFR 60.11(d) to minimize SO_2 emissions at FCU 600.

As specified by the Consent Decree in Civil No. 2:12-CV-00207, SO_2 emissions during periods of Startup, Shutdown, or Malfunction shall be used in determining compliance with the “365-day rolling average” SO_2 emission limits required by the Consent Decree in Civil No. 2:12-CV-00207 at FCU 600.

(i) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the emissions of CO from FCU 600 shall not exceed 500 ppmvd on a 1-hour average basis corrected to 0% O2.

As required by the Consent Decree in Civil No. 2:12-CV-00207, CO emissions during periods of Startup, Shutdown or Malfunction shall not be used in determining compliance with the 1-hour 500 ppmv emission limit, provided that during such periods the Permittee implements good air pollution control practices to minimize CO emissions at FCU 600.

(j) FCU 600 VOC Emissions
Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than December 31, 2013, the emissions of VOC from FCU 600 shall not exceed 3.3 pounds per 1000 barrels fresh feed.

Compliance Determination Requirements

D.22.9 Compliance Determination Requirements

(a) Pursuant to SSM 089-32033-00453, in order to demonstrate compliance with Conditions D.22.3 (a), (c) and (d), the emissions of NO_X, SO_2 and CO shall be calculated as the sum of the quantity in tons of the pollutant for the most recent complete calendar month and the previous 11 calendar months. Each month shall be calculated as follows:

Emissions (ton/mo) = $\sum^{n}$ **[{(**C_A x MWpollutant)/1,000,000} x {(Qstack/V_m) x (60 min/hr) x (1 ton / 2,000 lbs)}]$_i$

Where:

n = Hours in the month
Qstack = Actual hourly volumetric flow rate of flue gas from the FCU stack, dscf/min; calculated from process data or measured by stack flow meter (at 68 °F)
C_A = Actual hourly average pollutant concentration (ppmv) dry basis;
V_m = 385.3 dscf of gas per lb-mol at standard conditions (68 °F)

Where the calculated Qstack = Qr + Qesp + Qscr

Where:

Qr = Volumetric flow rate of exhaust gas from catalyst regenerator before adding air or gas streams, dscf/min; (at 68 °F)
Qesp = Volumetric flow rate of penthouse purge air to ESP, dscf/min; (at 68 °F)
Qscr = Volumetric flow rate of ammonia dilution air to SCR, dscf/min (at 68 °F)

Q_r = [79 x Q_{air} + (100-%O_{xy}) x Q_{oxy}] / [100 - %CO_2 - %CO - %O_2]

Where:

79 = Default concentration of nitrogen and argon in dry air, percent by volume (dry basis);
Qair = Volumetric flow rate of dry air to regenerator, dscf/min; (at 68 °F)
%Oxy = Oxygen concentration in oxygen-enriched stream, percent by volume (dry basis);
Qoxy = Volumetric flow rate of oxygen-enriched air stream to regenerator, dscf/min; (at 68 °F)
%CO2 = Carbon dioxide concentration in regenerator exhaust, percent by volume (dry basis);
%CO = Carbon monoxide concentration in regenerator exhaust, percent by volume (dry basis);
%O2 = Oxygen concentration in regenerator exhaust, percent by volume (dry basis);

(b) Pursuant to SSM 089-32033-00453, in order to demonstrate compliance with Condition D.22.3 (f), the coke burned shall be calculated as the sum of the quantity in lbs of coke burned for the most recent complete calendar month and the previous 11 calendar months. Each month shall be calculated as follows:

$R_{c(month)}$ (lbs/month) = $\sum^{n}$[K_1Q_r x (%CO_2 + %CO) + K_2Q_a – K_3Q_r x [(%CO/2) + %CO_2 + %O_2] + K_3Q_{oxy} x (%O_{xy})]$_i$

Where:

n = Hours in the month
$R_{c(month)}$= Coke burned, (lbs/month);
Q_r = Volumetric flow rate of exhaust gas from catalyst regenerator before adding air or gas streams boiler, dscm/min (dscf/min); (at 68 °F)

Q_a =	Volumetric flow rate of air to catalytic cracking unit catalyst regenerator, as determined from instruments in the catalytic cracking unit control room, dscf/min; (at 68 °F)
$\%CO_2$ =	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, 0.0186 (lb-min)/(hr-dscf-%));
K_2 =	Material balance and conversion factor, (0.1303 (lb-min)/(hr-dscf));
K_3 =	Material balance and conversion factor,(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,(dscf/min); and
$\%O_{xy}$ =	Oxygen concentration in oxygen-enriched air stream, percent by volume (dry basis)

(c) Demonstrating Compliance with FCU VOC Emission Limits

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, emissions of VOC from FCU 600 to demonstrate compliance with Condition D.22.8(j) - FCU 600 VOC Emissions shall be calculated as follows:

$$E = \left(\frac{C \times Q \times MW \times 60}{V_m}\right) \times \left(\frac{1000}{F}\right)$$

$$C = C_{total} - C_{methane} - C_{ethane}$$

Where:

E =	FCU VOC Emissions in lb/ 1000 bbl feed
C =	concentration of non-methane and non-ethane organic carbon as carbon in volume fraction
Ctotal =	concentration of total organic carbon in volume fraction, as carbon, as measured by EPA Method 25a
Cmethane =	concentration of methane in volume fraction, as carbon, as measured by EPA Method 18
Cethane =	concentration of ethane in volume fraction, as carbon, as measured by EPA Method 18
MW =	molecular weight of carbon = 12.01 lb/lb-mole
Q =	FCU stack flow in dry standard cubic feet per minute as measured by EPA Method (s) 1-4
1000 =	conversion factor to put emissions on a per 1000 bbl feed
Vm =	385.3 dscf of gas per lb-mol at standard conditions (68 °F)
F =	FCU feed rate in bbl/hour, averaged over period of source test
60 =	conversion factor for 60 minutes per hour

(d) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, the Permittee shall:

(1) No later than 180 Days after the “Date of Entry” of the Consent Decree entered in Civil No. 2:12-CV-00207, and on a semi-annual basis thereafter, the Permittee

shall conduct a performance test on FCU 600 pursuant to 40 .F.R. §§ 60.8 and 60.104a. Upon demonstrating through at least four (4) semi-annual tests that the PM limit in 40 C.F.R. § 60.102a(b)(1) is not being exceeded, the Permittee may reduce the required testing frequency to an annual basis. The Permittee shall provide notice to EPA no later than 30 Days in advance of the performance testing to be conducted pursuant to this paragraph, and shall provide the results of such testing upon request by EPA.

(2) In addition to the performance testing required by this paragraph, the Permittee may conduct testing to identify any parameters that may need to be maintained to assure compliance with the PM limits during testing. The Permittee shall provide EPA with notice no later than 30 Days in advance of testing to identify parameters pursuant to this paragraph, and shall provide the results of such testing upon request by EPA.

(e) Demonstrating Compliance with PM_{10} and PM_{TOTAL} Emission Limits

(1) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, compliance with the PM_{10} and PM_{TOTAL} emission limits in Condition D 22.3 - Emission Limits for PM_{10} and PM_{TOTAL} shall be based on the emission rate computed from the most recent performance test completed pursuant to Condition D.22.10 - FCU PM_{10} and PM_{Total} Performance Testing Requirements.

(2) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, the Permittee shall maintain compliance with the PM operating limits established under 40 C.F.R. § 60.102a(c)(1) during its demonstration of compliance with the PM_{10} and PM_{TOTAL} emission limits in Condition D.22.3 - Emission Limits for PM_{10} and PM_{TOTAL}.

(3) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207 , for the purposes of this paragraph, the Permittee may use Method 201A in lieu of Method 5 to determine PM_{TOTAL} emissions, provided that the Permittee follows the procedures in Method 201A for the collection and analysis of PM greater than 10 microns.

D.22.10 FCU PM_{10} and PM_{TOTAL} Performance Testing Requirement

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than 180 days after the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the Permittee shall implement a performance testing protocol in accordance with (a) through (e) as provided as follows:

Testing Frequency

(a) The Permittee shall conduct performance tests to measure emissions of PM_{10} and PM_{TOTAL} from FCU 600 on at least a semi-annual basis, with each semi-annual performance test being no sooner than four (4) calendar months from the date of completion of the previous semi-annual test. This shall not preclude the Permittee from conducting additional performance tests which are more frequent.

(1) Upon demonstrating, through at least four (4) valid, consecutive semi-annual tests conducted after December 31, 2013 that (i) the PM_{10} and PM_{TOTAL} limits (Condition D 22.3 - Emission Limits for PM_{10} and PM_{TOTAL}) are not being exceeded, (ii) the average of all four valid semi-annual tests is not more than 80% of the PM_{10} and PM_{TOTAL} limits and (iii) the average result from any valid

semi-annual test is not greater than 90% of the PM_{10} and PM_{TOTAL} limits, the Permittee may reduce the frequency of performance testing to an annual basis.

(2) The Permittee may request EPA approval to reduce the frequency of such testing in other circumstances. EPA has sole discretion to approve or disapprove the Permittee's request, which shall not be subject to Dispute Resolution. In the event that a subsequent annual test indicates an exceedance of a PM_{10} or PM_{TOTAL} limit, EPA may elect to reinstate the requirement for semi-annual testing. EPA's decision to reinstate semi-annual testing shall not be subject to Dispute Resolution.

Test Methods for PM_{10} and PM_{TOTAL} Emissions

(b) The Permittee shall measure PM_{10} emissions using EPA Methods 201A and 202. The Permittee may use EPA Method 5 in lieu of EPA Method 201A for purposes of demonstrating compliance with the PM_{10} emission limit (Condition D.22.3 - Emission Limits for PM_{10} and PM_{TOTAL}) provided that all PM measured by EPA Method 5 is considered as PM_{10}.

The Permittee shall measure PM_{TOTAL} emissions using EPA Methods 5 and 202. The Permittee may use EPA Method 201A in lieu of EPA Method 5 for purposes of demonstrating compliance with the PM_{TOTAL} emission limit provided that the Permittee also follows the procedures in EPA Method 201A for the collection and analysis of PM greater than 10 microns.

Test Run Duration

(c) Each performance test shall be comprised of at least three (3) valid two-hour stack test runs. The Permittee shall discard any invalid test runs, such as those that are compromised because of sample contamination. If a test run is discarded, it shall be replaced with an additional valid test run. The Permittee shall report the results of the discarded test runs and shall provide all information necessary to document why the test run was not valid.

Valid Performance Tests

(d) A PM_{10} and PM_{TOTAL} test shall not be considered a valid test, and the Permittee will not have met the requirement of this condition to test, unless each of the following conditions is met:

(1) The average FCU 600 coke burn rate for all runs used in determining compliance with the PM_{10} and PM_{TOTAL} emission limits must not be less than actual average FCU 600 coke burn rate over the time period since the previous performance test;

(2) The average SO_2 concentration for all runs used in determining compliance with the PM_{10} and PM_{TOTAL} emission limits must not be greater than 10 ppmvd @ 0% O_2; and

(3) The average total ammonia injection rate for all runs used in determining compliance with the PM_{10} and PM_{TOTAL} emission limits must not be less than average total ammonia injection rate over the time period since the previous performance test.

(4) Throughout the performance test, the Permittee shall target the average ESP total primary power since the last stack test. The average ESP total primary power for all the runs used in determining compliance with the PM_{10} and PM_{TOTAL} emission limits must not be greater than 120% of the average ESP total primary power since the last stack test.

Additional Parametric Monitoring During the Tests

(e) The Permittee shall monitor or calculate and record SO_2 concentration, NO_X concentration, catalyst additive rates, ammonia addition prior to ESP, ammonia slip, the FCU 600 coke burn-off rate, regenerator overhead temperatures, and FCU 600 feed rate for each test run. The Permittee shall reduce this monitoring data to an average that matches the time period of each test run.

Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures) and utilizing methods approved by the commissioner. Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.22.11 FCU VOC Performance Testing Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, and in order to demonstrate compliance with the emission limit in D.22.8 - FCU 600 VOC Emissions, by no later than December 31, 2013, and annually thereafter, the Permittee shall conduct performance tests to measure emissions of VOC from FCU 600, except as provided as follows:

(a) If a stack test for FCU 600 demonstrates that VOC emissions from FCU 600 are less than half of the applicable VOC emissions limit in Condition D.22.8 - FCU 600 VOC Emissions, the Permittee may thereafter elect to conduct stack tests at least once every three (3) years at FCU 600 in lieu of annual stack testing.

(b) If, after the Permittee exercises the option to conduct stack testing at least once every three (3) years pursuant to this paragraph, and a stack test thereafter demonstrates an exceedance of the applicable VOC emissions limit in Condition D.22.8 - FCU 600 VOC Emissions, the Permittee shall resume annual stack testing for FCU 600.

Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures) and utilizing methods approved by the commissioner. Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.22.12 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as required by Consent Decree No. 2:12-CV-00207, by no later than the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the Permittee shall use NO_X, SO_2, CO and O_2 CEMS to demonstrate compliance with the NO_X, SO_2 and CO limits in Conditions D.22.8(a), (b), (c), (e), (f), (g) and (i). The Permittee shall install, certify, calibrate, maintain and operate NO_X, SO_2, CO, and O_2 CEMS for FCU 600 in accordance with the provisions of 40 CFR 60.13 that are applicable to CEMS (excluding those provisions applicable only to Continuous Opacity Monitoring Systems) and Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B. The Permittee must conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed.

(b) The NO_X, CO, SO_2, and O_2 continuous emission monitoring systems (CEMS) for FCU 600 shall be calibrated, maintained, and operated for measuring NO_X, CO, and SO_2 emissions in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements

D.22.13 Continuous Monitoring [326 IAC 3-5][326 IAC 6.8-8]

(a) Condition C - Maintenance of Continuous Monitoring Equipment contains the Permittee's obligation with regard to the COMS monitoring required by this condition.

(b) Pursuant to 326 IAC 3-5 and 326 IAC 6.8-8-5(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), the Permittee shall continuously monitor coke burn off rate, in pounds per hour, as specified in the Continuous Compliance Plan (CCP).

D.22.14 Supplemental FCU PM Monitoring Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, by no later than the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the Permittee shall monitor and record the daily values for the following operating parameters:

(a) The feed rate, in barrels per day, for FCU 600;

(b) The average rate, in pounds per hour, at which SO_2-reducing catalyst additive is added to FCU 600; and

(c) The average amount of ammonia in pounds per hour that is separately injected into the FCU 600 vaporizer and FCU 600 ESP.

D.22.15 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.

D.22.16 Compliance Assurance Monitoring (CAM) [40 CFR Part 64]

(a) Pursuant to 40 CFR Part 64, the Permittee shall comply with the following Compliance Assurance Monitoring requirements for the electrostatic precipitator controlling FCU 600:

Monitoring Approach for PM_{10} and PM_{Total} Emissions From FCU 600			
Parameter	**Indicator No. 1**	**Indicator No. 2**	**Indicator No. 3**
I. Indicator	Proper Operation of Electrostatic Precipitator (ESP)	Particulate loading at the Electrostatic Precipitator (ESP) inlet	Inspection and Maintenance
Measurement Approach	Average ESP total primary power and secondary current.	Average exhaust coke burn-off rate	Inspections and Maintenance of the ESP
II. Indicator Range	An excursion is defined as a 3-hour rolling average ESP total primary power or secondary current falling below the level established in the most recent	An excursion is defined as a daily average exhaust coke burn-off rate exceeding the level established during the during the most recent performance	An excursion is defined as not following the inspection schedule and procedures specified in the Continuous Compliance Plan (CCP).

Monitoring Approach for PM_{10} and PM_{Total} Emissions From FCU 600			
Parameter	**Indicator No. 1**	**Indicator No. 2**	**Indicator No. 3**
	performance test conducted pursuant to 40 CFR §60.104a.	test conducted pursuant to 40 CFR §60.104a.	
III. Performance Criteria	--	--	--
A. Data Representativeness	Continuous Parameter Monitoring System (CPMS) requirements in 40 CFR 60.105a(b)(1)(i) and (iii).	Continuous Parameter Monitoring System (CPMS) requirements in 40 CFR 60.105a(b)(1)(iii) and (iv).	Recording, inspection, and maintenance procedures as prescribed in Condition D.22.13.
B. Verification of Operational Status	Data being reported to DCS on a continuous basis.	Data being reported to DCS on a continuous basis.	Records kept as prescribed in Condition D.22.13.
C. QA/QC Practices and Criteria	Periodic inspection and maintenance of the ESP and monitoring systems per CCP.	N/A	Update the CCP as needed.
D. Monitoring Frequency	Measure and record hourly average ESP total primary power and secondary voltage to the entire system per 40 CFR 105a(b)(1)(i).	Determine and record the average coke burn-off rate and hours of operation for FCU 600 per 40 CFR 105a(b)(1)(iv).	As prescribed in the CCP which meets the requirements of 326 IAC 6.8-8-7.
IV. Data Collection Procedure	Continuous Parameter Monitoring System meeting the requirements of 40 CFR 60.105a(b)(1)(i) and (iii).	Continuous Parameter Monitoring System meeting the requirements of 40 CFR 60.105a(b)(1)(iii) and (iv).	Per the methods prescribed in the CCP which meets the requirements of 326 IAC 6.8-8-7.
Averaging Period	3-hour average rolled hourly.	Daily average	N/A

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

D.22.17 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(C) and to document the compliance status 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 document the compliance status with Conditions D.22.3, D.22.6, D.22.12, D.22.13, and D.22.16, 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 the compliance status with Condition D.22.4(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) Pursuant to SPM 089-15202-00003, issued April 24, 2002, SPM 089-18588-00453, issued July 15, 2004, and to document the compliance status with Condition D.22.5, the Permittee shall maintain records of the 1-hour average CO emissions.

(e) In order to document the compliance status 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.

(f) In order to document the compliance status with Condition D.22.3, the Permittee shall maintain records of monthly emissions of SO_2, NO_X, and CO from FCU 600.

(g) To document compliance with Condition D.22.4(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(h) To document compliance with Condition D.22.7, the Permittee shall keep records pursuant to 40 CFR 60, Subpart Ja, as specified in Section F.3.

(i) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (c), (d), (e) and (f) of this condition.

D.22.18 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Condition D.22.2 the Permittee shall submit a report containing the average daily sulfur dioxide emission rate in pounds per hour not later than thirty (30) days after the end of each calendar quarter.

(b) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Condition D.22.6, the Permittee shall submit reports of excess opacity emissions not later than 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 the compliance status with Condition D.22.4(a), the Permittee shall submit reports as specified in the LDAR plan.

(e) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.22.3, D.22.5, and D.22.12, the Permittee shall submit reports of excess CO, SO_2, and NO_X emissions at FCU 600 not later than 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

(f) In order to document the compliance status with Condition D.22.3, the Permittee shall submit quarterly reports for the fresh feed used and coke burned at FCU 600 each month not later than thirty (30) days of the end of each quarter.

(g) In order to document the compliance status with Condition D.22.3, the Permittee shall submit quarterly reports of monthly emissions of SO_2, NO_X, and CO from FCU 600 not later than thirty (30) days of the end of each quarter.

(h) To document compliance with Condition D.22.4(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(i) To document compliance with Condition D.22.7, the Permittee shall submit reports pursuant to 40 CFR 60, Subpart Ja, as specified in Section F.3.

(j) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (b), (c), (d), (e), (f) and (g) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

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

Emissions Unit Description:

(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

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

The No. 1 SPS Boilers 5, 6 and 7 were permanently shut down as of April 1, 2010 as specified in Consent Decree 2:96CV 095RL.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

SECTION D.24 EMISSIONS UNIT OPERATION CONDITIONS - No. 3 Stanolind Power Station

Emissions Unit Description:

(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
#31 Boiler	1948	575	503-01	(pre SPM 089-25488-00453) low- NO_X burners, an induced flue gas recirculation (IFGR) system, and an over fired air (OFA) system
#32 Boiler	1948	575	503-02	Per SPM 089-25488-00453 : The low- NO_X burners, IFGR and OFA will be replaced by conventional burners and a Selective Catalytic Reduction (SCR) system on Boilers # 31, 32, 33, 34, 36
#33 Boiler	1951	575	503-03	
#34 Boiler	1951	575	503-04	
#36 Boiler	1953	575	503-05	

* Boiler #31, #32, #33, #34, and #36 stacks have continuous emissions monitors (CEMS) for NOx and CO.

(2) Five (5) direct-fired duct burners, permitted in 2008 (SPM 089-25488-00453), rated at 41 mmBTU/hr each, equipped with low NO_X burners and controlled by a Selective Catalytic Reduction (SCR) system. The duct burner stacks have continuous emissions monitors (CEMS) for NOx and CO.

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

(4) Insignificant Activity: one (1) glycol dehydration unit (GDU) to remove water from the refinery fuel gas system to reduce corrosion, which is composed of a glycol contactor and a stripper. Natural gas is used as the stripping medium The unit consists of the following equipment: a small (approx. 1,500 gal) tank to deliver glycol to the system, a glycol system of approx. 8,000 gal in capacity, heat exchangers and a coalescer, coolers, condensers, a glycol contactor, a glycol regenerator with a reboiler and stripper, and filters (carbon and sock types).

Insignificant Activity

(f) Emission units with $PM/PM_{10}/PM_{2.5}$ 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)]:

(6) One (1) lime loading operation at the Main Water Treatment Plant, consisting of two (2) lime silos (Lime Storage Bin North – UT 207 and Lime Storage Bin South- UT 208), permitted in 2014, controlled by one (1) bin vent filter. [326 IAC 6.8-1-2(a)]

(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 PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6, PM_{10} emissions from each stack serving No. 3 power station boilers #31, #32, #33, #34 and #36 shall not exceed 0.0075 pounds per million Btu heat input and 4.28 pounds per hour for each boiler.

These emission limits are specific to the boilers and do not apply to the duct burners or collateral emissions associated with selective catalytic reduction (SCR).

D.24.2 Lake County PM_{10} Emissions Limitations [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2, PM emissions from the five (5) duct burners and the lime loading operation shall each 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 #31, #32, #33, #34 and #36 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 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for No. 3 Stanolind Power Station Boilers 31, 32, 33, 34 and 36 and the duct burners:

(a) After the installation of the five (5) duct burners and the conventional burners and a Selective Catalytic Reduction (SCR) on boilers 31, 32, 33, 34 and 36, the Permittee shall comply with the following :

(1) The emissions of VOC from the five (5) duct burners shall not exceed 0.0054 pound per million BTU.

(2) The firing rate (total) at the five (5) boilers shall not exceed 24,303,535 mmBTU per 12 consecutive month period, with compliance determined at the end of each month.

(3) 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.

(4) The emissions of CO (total) from boilers 31, 32, 33, 34, and 36 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.

(b) Pursuant to SSM 089-32033-00453, the Permittee shall comply with the following for No. 3 Stanolind Power Station Boilers 31, 32, 33, 34, and 36 and the duct burners:

(1) The total emissions of NO_X from the five (5) duct burners shall not exceed 17.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(2) The emissions of PM from each of the five (5) duct burners shall not exceed 0.012 pound per million BTU.

(3) The emissions of PM_{10} from each boiler/SCR stack shall not exceed 0.010 pound per million BTU.

(c) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.24.6. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.24.5 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, the No. 3 SPS five (5) duct burners are affected facilities for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60,Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for the No.3 SPS five (5) duct burners.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, No. 3 SPS Boilers 31, 32, 33, 34, and 36 shall be affected facilities for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for No. 3 SPS Boilers 31, 32, 33, 34.

D.24.6 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the No. 3 SPS is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Sections F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the No. 3 SPS no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The No. 3 SPS shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.24.7 Clean Air Interstate Rule (CAIR) NO_X Ozone Season Trading Program [326 IAC 24-3]

Pursuant to 326 IAC 24-3, the Permittee shall comply with the Clean Air Interstate Rule (CAIR) NO_X Ozone Season Trading Program requirements for boilers #31 through #34 and #36, which are specified in Section E.1.

D.24.8 Operating Requirement

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and 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 31, 32, 33, 34, and 36 and the five (5) duct burners.

(b) Within 90 days of start-up after the installation of the five (5) duct burners and the conventional burners and the Selective Catalytic Reduction (SCR) units on Boilers 31, 32, 33, 34, and 36, pursuant to Permit SSM 089-25484-00453, issued May 1, 2008, the emissions of NO_X from Boilers 31, 32, 33, 34, and 36 shall not exceed 0.02 pound per million BTU, as a “365-day rolling average”.

D.24.9 Consent Decree (Civil No. 2:12-CV-00207) Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in Boilers 31, 32, 33, 34, and 36 and the five (5) duct burners shall not exceed 70 ppmvd total sulfur calculated as H_2S on a "12-month rolling average' basis.

Compliance Determination Requirements

D.24.10 Compliance Determination Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, compliance with the NO_X emission limits in Conditions D.24.4(b)(1) shall be calculated using the following equation:

E_{tpy} = lb/mmBTU [NO_X] * H * 1 ton/2000 lbs.			
Where:			
	E_{tpy}	=	Stack [NO_X] emissions in tons per year
	lb/mmBTU	=	lb/mmBTU calculated using 40 CFR Part 60, Appendix A, Method 19, using the average concentration as measured by the CEMS over the preceding 12 months.
	H	=	Total heat input in mmBTU to the unit from all fuels fired in the unit over the previous rolling 12-month period

D.24.11 Performance Testing Requirements

Pursuant to SSM 089-32033-00453, the Permittee shall perform VOC testing of SPS #31 Boiler, #32 Boiler, #33 Boiler, #34 Boiler, and #36 Boiler and the five (5) direct-fired duct burners utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Condition D.0.4 – Initial Testing Requirements for Existing Affected Emissions Units contains the Permittee’s requirements with regards to the initial compliance demonstration for VOC testing of SPS #31 Boiler, #32 Boiler, #33 Boiler, #34 Boiler, and #36 Boiler and the five (5) direct-fired duct burners. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee’s obligation with regard to the performance testing required by this condition.

D.24.12 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in the No. 3 SPS Boilers 31, 32, 33, 34, and 36 and the five (5) duct burners. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) The Total Sulfur Continuous Analyzers, CO and NO_X continuous emission monitoring systems (CEMS) for the boiler/duct burner stacks shall be calibrated, maintained, and operated for measuring total sulfur, CO and NO_X in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment.

Compliance Monitoring Requirements

D.24.13 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.24.14 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document the compliance status with Conditions D.24.3 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 8-4-8 and to document the compliance status with Condition D.24.6(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(c) In order to document the compliance status with Condition D.24.4, the Permittee shall maintain records of monthly firing rates and CO emissions at No. 3 Stanolind Power Station boilers 31, 32, 33, 34, 36 and the five (5) duct burners.

(d) Pursuant to 40 CFR 60, Subpart Ja and to document the compliance status with Condition D.24.5, the Permittee shall maintain the records specified in Section F.3.

(e) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Condition D.24.6(b), the Permittee shall maintain records as specified in Section F.9.

(f) Pursuant to 326 IAC 3-5-6 and to document the compliance status with Condition D.24.12, 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.

(g) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (c), and (f) of this condition.

D.24.15 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Conditions D.24.3 and D.24.8, the Permittee shall submit a report to IDEM, OAQ not later than 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 the compliance status with Condition D.24.6(a) the Permittee shall submit reports as specified in the LDAR plan.

(c) Pursuant to 40 CFR 60, Subpart Ja and to document the compliance status with Condition D.24.5, the Permittee shall submit reports as specified in Section F.3.

(d) In order to document the compliance status with Condition D.24.4, the Permittee shall submit a quarterly summary of the monthly firing rates and CO emissions for the boilers 31, 32, 33, 34, 36, and five (5) duct burners not later than thirty (30) days after the end of the quarter being reported.

(e) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.24.4 and D.24.12, the Permittee shall submit reports of excess CO and NO_X emissions not later than 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.

(f) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Condition D.24.6(b), the Permittee shall submit reports as specified in Section F.9.

(g) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (b), (d) and (e) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.25 EMISSIONS UNIT OPERATION CONDITIONS - Hazardous Waste Treatment Facility

Emissions Unit Description:

(y) Hazardous Waste Treatment System:

(1) Dewatering system for processing sludge, per SSM 089-25484-00453, issued May 1, 2008, 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. The feed rate capacity at the DAF/API dewatering system is 60,000 gallons per day. This facility includes the following emission sources and may 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;

(E) One (1) vapor recovery system on the dewatering system including a wet scrubber and carbon canister system.

(2) One (1) dewatering system, identified as the DNF dewatering system, approved in 2014 for construction, equipped with multiple frac tanks, electric boilers, centrifuges, and a wet scrubber, will be installed as part of the Lakefront Upgrades Project to process float and sludge from the Dissolved Nitrogen Floatation (DNF) System. The feed rate capacity will be 505,000 gallons per day. Vapors from the system will be routed to dual carbon canisters.

(3) One (1) Tank Cleaning Dewatering System, approved in 2014 for construction, equipped with multiple frac tanks, electric boilers, centrifuges, and a wet scrubber for processing sludge during routine cleaning of TK-5050, TK-5051, and TK-5052. The feed rate capacity will be 240,000 gallons per day. Vapors from the system will be routed to dual carbon canisters.

(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 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, 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 DAF/API 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

NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.25.2 Emission Offset [326 IAC 2-3]

In order to render 326 IAC 2-3 not applicable, the Permittee shall comply with the following for the dewatering systems:

(a) The VOC emissions from the DNF dewatering systems shall not exceed 7.3 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The VOC emissions from the Tank Cleaning Dewatering System, constructed as part of the Lakefront Upgrades Project, shall not exceed 0.5 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

Compliance with the VOC emissions limits , in conjunction with the emissions limits in Condition D.26.5, shall ensure that the project emissions increases, including fugitive emissions, for VOC for the Lakefront Upgrades Project remain below the significant levels, rendering 326 IAC 2-3 not applicable for these pollutants.

D.25.3 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

D.25.4 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.25.5 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 request the Permittee to revise the plan.

Compliance Determination Requirements

D.25.6 VOC Control

(a) In order to ensure compliance with Condition D.25.2, the carbon canisters for VOC control shall be in operation and control emissions from the DNF dewatering system and the Tank Cleaning Dewatering System at all times the DNF dewatering system and the Tank Cleaning Dewatering System are in operation.

(b) Pursuant to Significant Source Modification 089-33530-0045, per sub-paragraphs 52.a.i and ii, of section J of the Consent Decree entered in Civil No. 2:12-CV-00207, the vapor recovery and carbon canister systems for the DNF dewatering system, and Tank Cleaning Dewatering System shall consist of primary and secondary carbon canisters, operated in series (the “dual-canister” option). BP may comply with the requirements of the dual canister option required under this sub-paragraph by using a single canister with a “dual carbon bed” if the dual carbon bed configuration allows for breakthrough monitoring between the primary and secondary beds in accordance with the following:

(1) BP shall conduct breakthrough monitoring between the primary and secondary carbon canisters or beds when there is actual flow to the carbon canister. Such monitoring shall be conducted in accordance with the frequency specified in 40 CFR 61.354(d) using as the design basis the applicable breakthrough definition specified in sub-paragraph 52.a.iii of section J of the Consent Decree entered in Civil No. 2:12-CV-00207 (Condition D.25.9(d)). If a carbon canister or bed becomes unsafe to monitor because it is located within a temporary exclusion zone, BP shall monitor the canister or bed as soon as is practicable after the exclusion zone is no longer in effect, but in no case later than the end of the normal monitoring interval for the canister or bed or within 3 days of the end of the exclusion period, whichever is sooner.

(c) In order to demonstrate compliance with Condition D.25.2, monthly emissions from the DNF dewatering system and the Tank Cleaning Dewatering System shall be calculated as follows:

VOC Emissions (ton/month) = $\Sigma^n[C_{VOC} * 10^{-6} * F_{Vent} * MW * P / (R * T)] / 2000$ (lb/ton)

where:

n =	number of days per month;
C_{VOC} (ppmv) =	measured VOC concentration at carbon canister outlet or 50 ppmv;
F_{Vent} (scf/day) =	daily average carbon canister vent exhaust flow, at 519.7 R (60°F) and 14.7 psia (1 atm);
MW (lb/lbmol) =	molecular weight of vent exhaust as determined by Condition D.25.7 - Sampling Requirements;
P (psia) =	14.7 psia;
T (R) =	519.7 R; and
R (ft^3 psi R^{-1} $lbmol^{-1}$) =	Universal Gas Constant, 10.731 ft^3 psi R^{-1} $lbmol^{-1}$.

If the Permittee opts to use the measured VOC concentration in lieu of 50 ppmv, the VOC concentration shall be determined in accordance with 40 CFR 61.354(a)(1), as in effect on May 13, 2013.

D.25.7 Sampling Requirements

(a) Not later than 30 days after the startup of the DNF dewatering system, the Permittee shall sample and determine the molecular weight of the vent exhaust from the dual carbon canisters controlling the DNF dewatering system. Subsequent sampling and determination of molecular weight shall be performed at least once per quarter.

(b) The Permittee shall sample and determine the molecular weight of the vent exhaust from the dual carbon canisters controlling the Tank Cleaning Dewatering System at least once per quarter when the Tank Cleaning Dewatering System is in operation or once per cleaning event, whichever is more frequent.

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.

D.25.9 Carbon Canister Monitoring [40 CFR 64]

In order to demonstrate compliance with Condition D.25.2, the Permittee shall comply with the following:

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(a) A continuous monitoring system shall be calibrated, maintained, and operated on the dual carbon canisters for measuring the vent exhaust flow rate. For the purpose of this condition, continuous means no less often than once per fifteen (15) minutes.

(b) For a carbon adsorption system that regenerates the carbon bed directly in the control device such as a fixed-bed carbon adsorber, either:

(1) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the carbon bed; or

(2) A monitoring device equipped with a continuous recorder to measure a parameter that indicates the carbon bed is regenerated on a regular, predetermined time cycle.

(c) 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.

(d) Breakthrough Definition:
Pursuant to Significant Source Modification 089-33530-0045, per sub-paragraph 52.a.iii of Section J of the Consent Decree entered in Civil No. 2:12-CV-002072, breakthrough shall be considered either 50 ppmv VOC or 1 ppmv benzene. BP shall immediately replace the primary carbon canister or bed when the design value for the primary canister or bed is exceeded (as monitored between the primary and secondary carbon canisters or carbon beds). Unless both the primary and secondary carbon canisters or beds are replaced with fresh ones, the original secondary carbon canister or bed shall become the new primary carbon canister or bed and a fresh secondary carbon canister or bed shall be installed. In all cases, any carbon canister or bed used as the primary unit shall have sufficient capacity to meet the breakthrough definition of this sub-paragraph. For purposes of this sub-paragraph, “immediately” means no later than within twenty-four (24) hours.

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

D.25.10 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.25.5, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(b) In order to demonstrate the compliance status with Conditions D.25.2, D.25.6, and D.25.7, the Permittee shall maintain records in accordance with (1) through (6) below. Records maintained for (1) through (6) shall be taken as stated below and shall be complete and sufficient to establish compliance with the VOC limit established in Condition D.25.2:

(1) The number of days per month used in the equation in Condition D.26.6(c).

(2) The C_{VOC} used to calculate the equation in Condition D.26.6(c).

(3) The daily average carbon canister vent exhaust flow, at 519.7 R (60^{o} F) and 14.7 psi (1 atm).

(4) The molecular weight of the vent exhaust for the DNF dewatering system and Tank Cleaning Dewatering System.

(5) The VOC emissions from the DNF dewatering system (ton/month).

(6) The VOC emissions from the Tank Cleaning Dewatering System (ton/month).

(c) In order to demonstrate the compliance status with Condition D.25.9:

(1) If a carbon adsorber that regenerates the carbon bed directly on site in the control device 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.

(2) 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.

(d) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

D.25.11 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.25.5, the Permittee shall submit reports as specified in the LDAR plan.

(b) A quarterly summary of the information to document the compliance status with Condition D.25.2 shall be submitted not later than thirty (30) days after the end of the quarter being reported.

(c) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.26 EMISSIONS UNIT OPERATION CONDITIONS - Wastewater Treatment Plant

Emissions Unit Description:

(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. As part of the Lakefront Upgrades (LFU) Project, approved in 2014 for modification, the larger solids in the wastewater will be removed in the new Solids Collection System. Then the wastewater will be routed to tanks TK-5050, TK-5051 and TK-5052, which will operate in parallel and serve as oil-water separators, equalization, and stormwater surge. Floating oil will be separated and skimmed from the tanks and recycled. The water will be routed to the new Dissolved Nitrogen Floatation (DNF) Units to remove suspended solids and oil, which will be 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 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, solids tank TK-562, which will vent to carbon canisters by no later than the startup of the new Dissolved Nitrogen Floatation (DNF) System, installed as a part of the Lakefront Upgrades Project; and Dissolved 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 TK-5051 to DAF), DAF Flash Mixer, DAF Influent Channel, DAF Effluent Channel, DAF Primary Boxes, and DAF Sump.

(3) One (1) oil-water separation, equalization, and stormwater surge tank (identified as Tank TK-5051) having a maximum storage capacity of 10,000,000 gallons, constructed in 1988 and equipped with an external floating roof.

(4) One (1) oil-water separation, equalization, and stormwater surge tank (identified as Tank TK-5050) having a maximum storage capacity of 10,000,000 gallons, constructed in 1988. As part of the Lakefront Upgrades Project, TK-5050 will be equipped with an external floating roof, constructed in 2014.

(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) oil-water separation, equalization, and stormwater surge tank (identified as Tank TK-5052) having a maximum storage capacity of 11,676,000 gallons, to be constructed as part of the WRMP Project. This tank is equipped with an external floating roof.

(7) A brine treatment system with four (4) fixed roof tanks equipped with an iron sponge, constructed as part of WRMP project, identified as:

(A) TK-101, with a storage capacity of 128,972 gallons;
(B) TK-102, with a storage capacity of 128,972 gallons;
(C) TK-103, with a storage capacity of 128,972 gallons; and
(D) TK-104, with a storage capacity of 51, 580 gallons.

(8) A Dissolved Nitrogen Floatation (DNF) system, which vents to a dual carbon canister system, approved in 2014 for construction, as part of the Lakefront Upgrades Project, identified as:

(A) Four (4) parallel units, T-310, T-320, T-330, and T-340, with a maximum annual flow of 9,855 million gallons per year; and

(B) Two (2) fixed-cover float and sludge handling tanks, TK-303 and TK-304, with a storage capacity of 12,666 gallons each.

(9) One (1) Solids Collection System, which consists of the J-92 pump lift station and strainer backwash system, with a storage capacity of 5,257 gallons, constructed as part of the Lakefront Upgrades Project.

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

(11) Sewer components associated with the Lakefront Upgrades 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.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 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.

D.26.3 Consent Decree (Civil No. 2:12-CV-00207) Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, the Brine Treatment Tanks (TK-101, TK-102, TK-103 and TK-104) shall be equipped with fixed roofs and shall be vented to (i) an iron sponge control system followed by (ii) a carbon canister meeting the requirements of 40 CFR § 61.349(a)(2) and Paragraph 52 of Section J of the Consent Decree entered in Civil No. 2:12-CV-00207. Subject to EPA approval, the Permittee shall have the ability to utilize an alternative to the carbon canister authorized by 40 CFR § 61.349(a)(2).

D.26.4 Emissions Monitoring

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, for the brine treatment system the Permittee shall monitor the daily average H_2S concentration on the outlet of the iron sponge system and daily total vapor flow to the iron sponge system. Process analyzers calibrated in accordance with manufacturer's recommendations may be used for this purpose.

D.26.5 Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) The VOC emissions from the Dissolved Nitrogen Floatation (DNF) System, constructed as part of the Lakefront Upgrades Project, shall not exceed 10.4 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) By no later than the startup of the new Dissolved Nitrogen Floatation (DNF) System, constructed as a part of the Lakefront Upgrades Project, emissions from TK-562 shall be routed to a carbon canister control device that meets all applicable control and/or treatment requirements under the Benzene Waste Operations NESHAP.

Compliance with the VOC emissions limits, in conjunction with the emissions limits in Condition D.25.2, shall ensure that the project emissions increases, including fugitive emissions, for VOC for the Lakefront Upgrades Project remain below the significant levels, rendering 326 IAC 2-3 not applicable for these pollutants.

D.26.6 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for these facilities and any control devices. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

Compliance Determination Requirements

D.26.7 VOC Control

(a) In order to ensure compliance with Condition D.26.5, the carbon canisters for VOC control shall be in operation and control emissions from the Dissolved Nitrogen Floatation (DNF) System and TK-562 at all times the DNF and TK-562 are in operation.

(b) Pursuant to Significant Source Modification 089-33530-0045, per sub-paragraphs 52.a.i and ii, of section J of the Consent Decree entered in Civil No. 2:12-CV-00207, the vapor recovery and carbon canister systems for the Dissolved Nitrogen Floatation (DNF) System and TK-562 shall consist of primary and secondary carbon canisters, operated in series (the “dual-canister” option). BP may comply with the requirements of the dual canister option required under sub-paragraph by using a single canister with a “dual carbon bed” if the dual carbon bed configuration allows for breakthrough monitoring between the primary and secondary beds in accordance with the following:

(1) BP shall conduct breakthrough monitoring between the primary and secondary carbon canisters or beds when there is actual flow to the carbon canister. Such monitoring shall be conducted in accordance with the frequency specified in 40 CFR 61.354(d) using as the design basis the applicable breakthrough definition specified in sub-paragraph 52.a.iii of section J of the Consent Decree entered in Civil No. 2:12-CV-00207 (Condition D.26.9(d)). If a carbon canister or bed becomes unsafe to monitor because it is located within a temporary exclusion zone, BP shall monitor the canister or bed as soon as is practicable after the exclusion zone is no longer in effect, but in no case later than the end of the normal monitoring interval for the canister or bed or within 3 days of the end of the exclusion period, whichever is sooner.

(c) In order to demonstrate compliance with Condition D.26.5(a), monthly emissions from the Dissolved Nitrogen Floatation (DNF) System shall be calculated as follows:

VOC Emissions (ton/month) = $\Sigma^{n}[C_{VOC} * 10^{-6} * F_{Vent} * MW * P / (R * T)] / 2000$ (lb/ton)

where:
n = number of days per month;

C_{VOC} (ppmv) =	measured VOC concentration at carbon canister outlet or 50 ppmv;
F_{Vent} (scf/day) =	daily average carbon canister vent exhaust flow, at 519.7 R (60°F) and 14.7 psia (1 atm);
MW (lb/lbmol) =	molecular weight of vent exhaust as determined by Condition D.26.8 - Sampling Requirements.
P (psia) =	14.7 psia;
T (R) =	519.7 R; and
R (ft^3 psi R^{-1} $lbmol^{-1}$) =	Universal Gas Constant, 10.731 ft^3 psi R^{-1} $lbmol^{-1}$.

If the Permittee opts to use the measured VOC concentration in lieu of 50 ppmv, the VOC concentration shall be determined in accordance with 40 CFR 61.354(a)(1), as in effect on May 13, 2013.

D.26.8 Sampling Requirements

Not later than 30 days after the startup of the Dissolved Nitrogen Floatation (DNF) System, the Permittee shall sample and determine the molecular weight of the vent exhaust from the dual carbon canisters controlling the Dissolved Nitrogen Floatation (DNF) System. Subsequent sampling and determination of molecular weight shall be performed at least once per quarter.

Compliance Monitoring Requirements

D.26.9 Carbon Canister Monitoring [40 CFR 64]

In order to demonstrate compliance with Condition D.26.5, the Permittee shall comply with the following:

(a) A continuous monitoring system shall be calibrated, maintained, and operated on the dual carbon canisters for measuring the vent exhaust flow rate. For the purpose of this condition, continuous means no less often than once per fifteen (15) minutes.

(b) For a carbon adsorption system that regenerates the carbon bed directly in the control device such as a fixed-bed carbon adsorber, either:

(1) A monitoring device equipped with a continuous recorder to measure either the concentration level of the organic compounds or the benzene concentration level in the exhaust vent stream from the carbon bed; or

(2) A monitoring device equipped with a continuous recorder to measure a parameter that indicates the carbon bed is regenerated on a regular, predetermined time cycle.

(c) 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.

(d) Breakthrough Definition:
Pursuant to Significant Source Modification 089-33530-0045, per sub-paragraph 52.a.iii of Section J of the Consent Decree entered in Civil No. 2:12-CV-002072, breakthrough shall be considered either 50 ppmv VOC or 1 ppmv benzene. BP shall immediately replace the primary carbon canister or bed when the design value for the primary canister or bed is exceeded (as monitored between the primary and secondary carbon canisters or carbon beds). Unless both the primary and secondary carbon canisters or beds are replaced with fresh ones, the original secondary carbon canister or bed shall become the new primary carbon canister or bed and a fresh secondary carbon canister or bed shall be installed. In all cases, any carbon canister or bed used as the primary unit shall have sufficient capacity to meet the breakthrough definition of this sub-paragraph. For purposes of this sub-paragraph, “immediately” means no later than within twenty-four (24) hours.

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

D.26.10 Record Keeping Requirements

(a) In order to document the compliance status with Condition D.26.4, the Permittee shall maintain records of the daily average H2S concentration on the outlet of the iron sponge system and daily total vapor from to the iron sponge system.

(b) In order to demonstrate the compliance status with Condition D.26.5(a), D.26.7, and D.26.8, the Permittee shall maintain records in accordance with (1) through (5) below. Records maintained for (1) through (5) shall be taken as stated below and shall be complete and sufficient to establish compliance with the VOC limit established in Condition D.26.5(a):

(1) The number of days per month used in equation D.26.7(c).

(2) The C_{VOC} used to calculate the equation in Condition D.26.7(c).

(3) The daily average carbon canister vent exhaust flow, at 519.7 R (60^{o} F) and 14.7 psi (1 atm).

(4) The molecular weight of the vent exhaust for the Dissolved Nitrogen Floatation (DNF) System.

(5) The VOC emissions from the Dissolved Nitrogen Floatation (DNF) System (ton/month).

(c) In order to demonstrate the compliance status with Condition D.26.9:

(1) If a carbon adsorber that regenerates the carbon bed directly on site in the control device 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.

(2) 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.

(d) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

D.26.11 Reporting Requirements

(a) In order to document the compliance status with Condition D.26.4, the Permittee shall submit quarterly reports for the H2S emissions from the brine treatment system not later than thirty (30) days of the end of the reporting quarter.

(b) A quarterly summary of the information to document the compliance status with Condition D.26.5 shall be submitted not later than thirty (30) days after the end of the quarter being reported.

(c) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.27 EMISSIONS UNIT OPERATION CONDITIONS - Oil Movements

Emissions Unit Description:

(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) One (1) internal floating roof storage tank identified as 3727, storing either petroleum hydrocarbon with vapor pressure less than 0.5 psia or ethanol, constructed in 1948, with a maximum storage capacity of 857,717 gallons.

(3) 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
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

(4) Sixty-six (66) 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
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
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

(5) 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
TK-0563	WWTP	Aux. Fuel Oil	1971	49,378	<0.5

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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-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	2014*	3,357,627	<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	2014*	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-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-2279	MARINE DOCK	LCCO/DCO Line Wash	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	--	--	--
3490		--	1925	3,373,413	<0.5
3495		--	1992	3,876,768	<0.5

*These units were permitted for construction in 2014. The exact construction years will be added after construction is complete.

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

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

(8) Two (2) Off-spec Brine Tanks, constructed as part of WRMP project, with internal floating roofs, identified as:

(A) TK-3559, with a storage capacity of 451,214 gallons
(B) TK-3560 with a storage capacity of 1,015,231 gallons

(9) As part of the WRMP project, BP is repurposing two existing tanks (TK-3911 and TK-3728 or an equivalent tank) to store diluent and two existing tanks (TK-3716 and TK-3475) to store heavy virgin naphtha.

(10) Fugitive components constructed as part of the Gas Oil Tanks Replacement Project, permitted in 2014.

(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) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, Oil Movements is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at Oil Movements no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) Oil Movements shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

(4) The two consecutive months of monitoring that the Permittee previously conducted for purposes of 40 CFR 60, Subpart GGG at Oil Movements (Indiana Tank Field, J & L Tankfield, Lake George Tank Field, Oil Movements Diluent, Oil Movements North, South Tank Field and Stieglitz Park Tank Field) satisfies the requirement to conduct monitoring of those components for two consecutive months following the initial applicability of 40 CFR 60, Subpart GGGa.

D.27.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) Tank 3703 shall remain inoperative.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, emissions of VOC from the Off-Spec Brine Tanks (TK-3559 & TK-3560) shall not exceed a total of 2.1 tons per rolling 12 month period, with compliance determined at the end of each month.

(c) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.27.1. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

D.27.3 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, 3510, 3511, 3512, 3513, 3514, 3525, 3526, 3527, 3528, 3531, 3532, 3533, 3549, 3553, 3554, 3558, 3601, 3605, 3622, 3624, 3629, 3639, 3641, 3701, 3702, 3704, 3707, 3715, 3716, 3727, 3728, 3730, 3900, 3904, 3905, 3907, 3909, 3911, 3912, 3914, 3915, 3916, 3917, 3918, 3919, 3920, 3492, 3529, 3631, 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.27.4 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 2279, 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, 3704, 3533, 3915, 3916, 3917, 3918, 3919, 3920, D-424, 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-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-3727, TK-3733, TK-3735, TK-3908, TK-3910, TK-3913, TK-3571, TK-3572, TK-3734, TK-3906, 3490, and 3495. For Storage tanks 3534, 3602, 3604, 3708, D-424, 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-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-3571, TK-3572, TK-3734, TK-3906, 3490, and 3495, 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.27.10(c). 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.27.10(c) and (g).

(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.27.5 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.27.6 Consent Decree (Civil No. 2:12-CV-00207) Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, the Permittee shall continue to operate and maintain an internal floating roof on each Off-Spec Brine Tank (TK-3559 and TK-3560) consistent with the requirements of 40 CFR 61.351(a)(1).

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, except for periods when an Off-Spec Brine Tank is out of service, the Permittee shall maintain in each Off-Spec Brine Tank (TK-3559 & TK-3560) a level sufficient to assure that the floating roof remains in contact with the liquid in the tank.

(c) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, using the throughput data collected per Condition D.27.9 and the most recent RVP measurement collected per Condition D.27.9, the Permittee shall use USEPA's "TANKS" model to determine, on a monthly basis, the monthly and rolling 12-month VOC emissions from the Off-Spec Brine Tanks TK-3559 &TK-3560.

Compliance Monitoring Requirements

D.27.7 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.

D.27.8 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)

D.27.9 Emissions Monitoring

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, for each of the Off-Spec Brine Tanks (TK-3559 & TK-3560), the Permittee shall:

(a) monitor throughput on a monthly total basis;

(b) sample the material in the tank off the tank’s floating suction line and measure the Reid Vapor Pressure (RVP) of any oil layer once per month.

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

D.27.10 Record 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 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.

(c) 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.

(d) 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.

(e) 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.

(f) 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.

(g) 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.

(h) To document compliance with Condition D.27.1(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(i) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and to document compliance with Condition D.27.2(b), the Permittee shall record the throughput data and the most recent RVP measurement collected and the USEPA's "TANKS" model output on a monthly basis.

(j) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (d), (c), (d), (e), (f), (g), (h), and (i) of this condition.

D.27.11 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.27.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) Pursuant to 326 IAC 8-9-6(c) and to document the compliance status with Condition D.27.8(b):

(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.

(c) Pursuant to 326 IAC 8-9-6(d) and to document the compliance status with Condition D.27.8(e)

(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.

(d) Pursuant to 326 IAC 8-9-6(e) and to document the compliance status with Condition D.27.4(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.

(e) 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.

(f) 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.

(g) 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.

(h) To document compliance with Condition D.27.1(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(i) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (b), (c), (d), (e), (f), and (g) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.28 EMISSIONS UNIT OPERATION CONDITIONS - Remediation System

Emissions Unit Description:

(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. 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-137	1992	999-02	Vented Separately	Uncontrolled
J-138	1991 Extension 1994	999-03	J-138 and J-140 are vented with D-138 (Vapor/Liquid separation tank)	0.685 mmBTU per hour Thermal Oxidizer ITF
J-140	1981	999-05		
J-141	1988 Extension 1993	999-06	Vented Separately	Uncontrolled
J-156	1968-1970	999-07	Vented with J-157	Uncontrolled
J-157	1968-1970	999-08	Vented with J-156	Uncontrolled
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), particulate matter (PM) emissions from the ITF thermal oxidizer shall not exceed 0.03 gr/dscf.

D.28.2 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.12 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 along with a significant permit modification within one hundred and eighty (180) days of the effective date of this Title V Permit Renewal No. T089-30396-00453.

(b) The Permittee shall be in compliance with the requirements of 326 IAC 8-7 not later than three hundred and sixty-five (365) days of the effective date of this Title V Permit Renewal No. T089-30396-00453.

D.28.3 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

D.28.4 Consent Decree (Civil No. 2:12-CV-00207) Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, "fuel oil" shall not be burned in any of the thermal oxidizers associated with the Remediation System.

Compliance Monitoring Requirements

D.28.5 Compliance Assurance Monitoring (CAM) Plan [40 CFR 64]

Pursuant to 40 CFR 64 (Compliance Assurance Monitoring (CAM)), in order to provide reasonable assurance of compliance with Conditions D.28.2, the Permittee shall comply with the J-138 and J-140 applicable HAP monitoring requirements of Section H.7 - 40 CFR 63, Subpart GGGGG (National Emission Standards for Hazardous Air Pollutants: Site Remediation). Compliance with these monitoring requirements satisfies CAM for VOC for J-138 and J-140.

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

D.28.6 Record Keeping Requirements

(a) To document the compliance status with Condition D.28.5 and the CAM record keeping requirements in 40 CFR 64.9, the Permittee shall maintain the following records for J-138 and J-140, on site:

(1) The daily average firebox temperature.

(2) The temperature established in the design evaluation or during the performance test whichever is the later.

(b) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

SECTION D.29 EMISSIONS UNIT OPERATION CONDITIONS - Mechanical Shop

Emissions Unit Description:

(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) Electric 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) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the Mechanical Shop shall be an affected facility for purposes of 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 - 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the Mechanical Shop no later than one year from the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The Mechanical Shop shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.29.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.29.1.

An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance Monitoring Requirements

D.29.3 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.29.4 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.29.1(a), the Permittee shall keep records as specified in the LDAR plan.

(b) To document compliance with Condition D.29.1(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(c) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraph (a) of this condition.

D.29.5 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.29.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) To document compliance with Condition D.29.1(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(c) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraph (a) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.30 EMISSIONS UNIT OPERATION CONDITIONS - Bulk Truck Loading Facility

Emissions Unit Description:

(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 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.30.2 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 H.1.

(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 H.1 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 H.1 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 (c).

(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 F.12.

(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 H.1 assures compliance with this condition.

D.30.3 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the Marketing Terminal is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the Bulk Truck Loading Facility no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The Marketing Terminal shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

(4) The two consecutive months of monitoring that the Permittee previously conducted for purposes of 40 CFR 60, Subpart GGGa at the Marketing Terminal satisfies the requirement to conduct monitoring of those components for two consecutive months following the initial applicability of 40 CFR 60, Subpart GGGa.

D.30.4 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.30.3, an instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

D.30.5 Particulate Matter Limitation (PM) [326 IAC 6.8-1-2(b)(3)]

Pursuant to 326 IAC 6.8-1-2(b)(3), 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.

D.30.6 Consent Decree (Civil No. 2:12-CV-00207) Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, "fuel oil" shall not be burned in the vapor combustion unit.

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

D.30.7 Record Keeping Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.30.3(a), the Permittee shall keep records as specified in the LDAR plan.

(b) To document compliance with Condition D.30.3(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(c) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraph (a) of this condition.

D.30.8 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.30.3(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) To document compliance with Condition D.30.3(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(c) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraph (a) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.31 EMISSIONS UNIT OPERATION CONDITIONS - Cooling Towers

Emissions Unit Description:

(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 WRMP 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 WRMP Project. Contemporaneous to the WRMP Project the other modules will be controlled with high efficiency drift eliminators.

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

Cooling Tower 7	22,000/982	high efficiency liquid drift eliminators
Cooling Tower 8	90,000/2956	high efficiency liquid drift eliminators

(4) Existing Cooling Towers affected by the WRMP project:

Cooling Tower 5	41,250/814	high efficiency liquid drift eliminators

(5) Associated heavy liquid pumps, heavy liquid valves, and heavy liquid pressure relief devices.

(6) One (1) modular back-up cooling tower system, identified as Modular Cooling Tower System, approved in 2014 for installation, to be brought onsite in the event that an existing cooling tower is out of service or operating at reduced rates for maintenance, repair, or replacement, with a maximum recirculation rate of 90,000 gallons per minute, with a maximum make-up rate of 3,000 gallons per minute, using high efficiency liquid drift eliminators as particulate control. This unit can stand in for Cooling Towers 1 through 8.

Insignificant Activities:

(hh) One (1) cooling tower, identified as Cooling Tower 1, with a maximum capacity of 35,000 gpm. [40 CFR 63, Subpart CC]

(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 2-1.1-4] 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 based on a 12 consecutive month average.

Compliance with these limits shall ensure 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 2-1.1-4 not applicable, after the installation of the liquid drift eliminators on Cooling Towers 2, 3, 4, after the tie-in of the GOHT to Cooling Tower 5 and the installation of Cooling Towers 7 and 8, the average concentration of total dissolved solids (TDS) of the water in Cooling Towers No. 2, 3, 4, 5, 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
5	1,576
7	1,163
8	1,163

(d) In order to render 326 IAC 2-3 (Emission Offset) not applicable, the VOC emissions from Cooling Tower 5 after tie-in of the GOHT, and from Cooling Towers No. 7 and 8 shall not exceed the following based on a 12 consecutive month average:

Cooling Tower	lb/hr
5	1.8
7	1.0
8	3.9

(e) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.31.3. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

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 WRMP project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.31.2 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2(a), particulate matter (PM) emissions from each cooling tower (Cooling Tower No. 2 - 8) shall not exceed 0.03 gr/dscf.

D.31.3 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 heavy liquid pumps, heavy liquid valves, and heavy liquid 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.31.4 Alternative Cooling Tower Operating Scenario

(a) In order to ensure compliance with Conditions D.31.1(a), D.31.1(b), D.31.1(c), and D.31.1(d), when the Modular Cooling Tower System is operating in place of one (1) of the cooling towers, identified as Cooling Towers 2 through 8:

(1) The total flowrate (including recirculation rate and make-up rate) for a cooling tower and the total flow rate (including recirculation rate and make-up rate) for the Modular Cooling Tower System, when operating in place of a cooling tower, shall not exceed the following:

Cooling Tower	Total Flowrate (MMgal per twelve (12) consecutive month period, with compliance determined at the end of each month)
2	26,955
3	48,130
4	23,697
5	22,109
6	10,512
7	12,079
8	48,858

(2) The average concentration of total dissolved solids (TDS) for a cooling tower and for the Modular Cooling Tower System, when operating in place of a cooling tower, shall not exceed the following:

Cooling Tower	Average TDS (mg/L) per twelve (12) consecutive month period
2	1,627
3	1,147
4	1,645
5	1,576
6	3,300
7	1,163
8	1,163

(3) The average VOC emissions from a cooling tower and from the Modular Cooling Tower System, when operating in place of a cooling tower, shall not exceed the following:

Cooling Tower	Average VOC Emissions (lb/hr) per twelve (12) consecutive month period
5	1.8
6	0.84
7	1.0
8	3.9

(b) In order to ensure compliance with Condition D.31.1(e), when the Modular Cooling Tower System is operating in place of one (1) of the cooling towers, identified as Cooling Towers 2 through 8, for all pumps involved in heavy liquid service, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.31.3 for that cooling tower. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits above shall ensure that 326 IAC 2-3 does not apply to Cooling Tower No. 6 when the Modular Cooling Tower System is operating in place of Cooling Tower 6. Additionally, compliance with the limits above, 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 WRMP 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 when the Modular Cooling Tower System is operating in place of Cooling Towers 2, 3, 4, 5, 7, and 8.

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

D.31.5 Operating Requirements

In order to demonstrate compliance with Condition D.31.1(c) and D.31.4(a)(2), the liquid drift eliminators shall be in operation and control PM and PM_{10} from Cooling Towers 2, 3, 4, 5, 7, 8, and the Modular Cooling Tower System at all times that these cooling towers and the fans are in operation, except when the cooling tower fans need to be reversed in accordance with the cooling tower manufacturers' recommendations to prevent physical damage to or malfunction of the tower.

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

D.31.6 Compliance Monitoring Requirements [326 IAC 2-3]

(a) To monitor compliance with Condition D.31.1(a), D.31.1(c), and D.31.4(a)(2), the Permittee shall take weekly measurements of the total dissolved solids (TDS) of the water in 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.31.1(d), the Permittee shall visually inspect the water going to Cooling Towers No. 5, 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.

(c) To monitor compliance with Condition D.31.4(a)(2), when the Modular Cooling Tower System is operating in place of one (1) of the cooling towers, identified as Cooling Towers 2 through 8, the weekly measurement of total dissolved solids (TDS) required in Condition D.31.6(a) shall be taken from the water in the Modular Cooling Tower System. If the respective cooling tower TDS limitation is exceeded, the Permittee shall perform quantitative water analyses and shall take the remedial action necessary to correct the problem.

(d) To monitor compliance with Condition D.31.4(a)(3), when the Modular Cooling Tower System is operating in place of one (1) of the cooling towers, identified as Cooling Towers 5 through 8, the weekly inspection required in Condition D.31.6(b) shall be conducted on the water going to the Modular Cooling Tower System. If VOC is observed, the Permittee shall take the remedial action necessary to correct the problem.

D.31.7 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 Requirement [326 IAC 2-7-5(3)][326 IAC 2-7-19]

D.31.8 Record Keeping Requirements [326 IAC 2-3]

(a) To document the compliance status with Condition D.31.1(a) and (c), the Permittee shall maintain records of the total dissolved solids (TDS) of the water in Cooling Towers No. 2, 3, 4, 5, 6, 7 and 8 and any remedial actions taken (including the date remedial actions were initiated).

(b) To document the compliance status with Condition D.31.1(b) and (d), the Permittee shall maintain records of the visual inspections required by D.31.4(b) and any remedial actions taken (including the date remedial actions were initiated).

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.31.3, the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR Plan.

(d) To document the compliance status with Condition D.31.5, the Permittee shall maintain records in accordance with (1) through (7) below. Records maintained for (1) through (7) shall be taken as stated below and shall be complete and sufficient to establish compliance with limits in Condition D.31.5.

(1) The dates that the Modular Cooling Tower System is used and for which cooling tower the Modular Cooling Tower System is operating.

(2) The total monthly and twelve (12) consecutive month total flowrate (including recirculation rate and make-up rate) for each cooling tower, identified as Cooling Tower 2 through 8, plus the total flowrate (including recirculation rate and make-up rate) from the Modular Cooling Tower System for each month when operating, for the dates and cooling towers specified in (1) above.

(3) The total dissolved solids of the water in the Modular Cooling Tower System as required in Condition D.31.6(c) and any remedial actions taken (including the date remedial actions were initiated).

(4) The total monthly and twelve (12) consecutive month total dissolved solids average for each cooling tower, identified as Cooling Tower 2 through 8, including any readings taken for the Modular Cooling Tower System when operating, for the dates and cooling towers specified in (1) above.

(5) Visual inspections of the water going to the Modular Cooling Tower System as required by D.31.6(d) and any remedial actions taken (including the date remedial actions were initiated).

(e) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

D.31.9 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.31.3, the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(b) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.32 EMISSIONS UNIT OPERATION CONDITIONS - Asphalt Facility

Emissions Unit Description:

(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 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 one (1) process heater:

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

(2) The following two (2) 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
569	5,544,000	1981
3613	8,866,200	1992

(3) The following six (6) 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
3571	5,040,000	1971
3572	5,040,000	1971
3609	5,649,000	1973
3611	8,513,400	1973
6126	3,108,000	1999
6127	3,108,000	2000

(4) The following five (5) 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-3614	Residual Oil and/or Asphalt	2007	14,154,000	141,120,000	< 0.0435	biofilter
TK-3615	Residual Oil and/or Asphalt	2007	14,154,000	141,120,000	< 0.0435	biofilter
TK-3616	Trim Gas Oil	2007	2,268,000	16,800,000	< 0.0435	biofilter
TK-3617	Trim Gas Oil	2007	2,268,000	16,800,000	< 0.0435	biofilter

Under 40 CFR 60, Subpart UU, storage tanks TK-3614 through TK-3617, are each considered an

affected facility.
Under 40 CFR 63, Subpart CC, storage tanks TK-3573, TK-3614 through TK-3617 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 and heat exchange systems.

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
F-300	9.9	Natural gas	none
F-400	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 Lake County PM_{10} Emission Limitations [326 IAC 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6, the Permittee must comply with the following PM_{10} emission limitations for the Asphalt facility process heater:

Process Heater	PM_{10} Limit (lbs/mmBTU)	PM_{10} Limit (lbs/hour)
F-2 Steiglitz Park Heater	0.0075	0.209

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 heater:

Process Heater	SO_2 Limit (lbs/mmBTU)	SO_2 Limit (lbs/hour)
F-2 Steiglitz Heater	0.033	0.90

D.32.3 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 569, 3613, 3571, 3572, 3609, 3611, 6126, 6127, TK-3573, TK-3614 through TK-3617, and TK-3570, the hot oil heaters F-300, F-400, 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.32.4 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the Asphalt Facility is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Sections Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the Asphalt Facility no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The Asphalt Facility shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.32.5 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.32.4. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

D.32.6 Natural Gas Usage Limit [326 IAC 2-2][326 IAC 2-3]

Pursuant to MSM 089-23723-00453 (issued February 20, 2007), the total natural gas usage shall not exceed 255 million cubic feet per twelve (12) consecutive month period for hot oil heaters F-300, F-400, 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.32.7 Preventive Maintenance Plan [326 IAC 2-7-5(12)]

A Preventive Maintenance Plan is required for the biofilter system. Section B - Preventive Maintenance Plan contains the Permittee's obligation with regard to the preventive maintenance plan required by this condition.

D.32.8 Operating Requirement

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and 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 hot oil heaters F-300, F-400, H-LG-1, H-LG-2 and H-LG-3.

(b) In order to comply with Section F.7 (40 CFR Part 60, Subpart UU), opacity from storage tanks TK-3614, TK-3615, TK-3616 and TK-3617 shall be controlled by the biofilter system at all times that the storage tanks are in operation.

Compliance Determination Requirements

D.32.9 Compliance Determination 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.

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

D.32.10 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 Requirement [326 IAC 2-7-5(3)][326 IAC 2-7-19]

D.32.11 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 6126, 6127, 569, 3613, 3571, 3572, 3609, 3611, TK-3573, TK-3614 through TK-3617, 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 6126, 6127, 569, 3613, TK-3573, TK--3614 through TK-3617, or TK-3570 exceeds seventy-five hundredths (0.75) psia.

D.32.12 Record Keeping Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(1)(A) and to document the compliance status with Conditions D.32.2, and D.32.8, the Permittee shall maintain a daily record of the following for the F-2 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 40 CFR 60, Subpart GGGa and to document the compliance status with Condition D.32.7(b), the Permittee shall keep records as specified in Section F.9.

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.32.7(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(d) To document the compliance status with Condition D.32.6, the Permittee shall record the total natural gas usage for hot oil heaters F-300, F-400, H-LG-1, H-LG-2, and H-LG-3 on a monthly basis;

(e) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a) and (c) of this condition.

D.32.13 Reporting Requirements

(a) Pursuant to 326 IAC 7-4.1-3(b)(2) and to document the compliance status with Conditions D.32.2 and D.32.9, the Permittee shall submit a report to IDEM, OAQ department not later than thirty (30) days after the end of each calendar quarter containing the average daily sulfur dioxide emission rate, for the F-2 Steiglitz Heater.

(b) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Condition D.32.4(b), the Permittee shall submit to IDEM, OAQ the reports specified in Section F.9.

(c) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.32.7(a), the Permittee shall submit reports as specified in the LDAR plan.

(d) A quarterly summary of the information to document the compliance status with Condition D.32.6 shall be submitted not later than thirty (30) days after the end of the quarter being reported.

(e) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a) and (c) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.33 EMISSIONS UNIT OPERATION CONDITIONS - Cogen Steam Transfer Line

Emissions Unit Description:
(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 the compliance status 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.

Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

D.33.3 Reporting Requirements

A quarterly summary of the information to document the compliance status with Condition D.33.1 shall be submitted not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. The report submitted by the Permittee does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.34 EMISSIONS UNIT OPERATION CONDITIONS - Marine Dock Facility

Emissions Unit Description:

(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 a contemporaneous project to the WRMP Project, gasoline loading at the Marine Dock Facility will cease. 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-2), 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 6.8-2-6]

Pursuant to 326 IAC 6.8-2-6(b), the F-100 marine docks distillate heater shall have the following emission limits:

The PM_{10} emissions shall not exceed 0.0075 pounds per million Btu heat input and 0.052 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) Pursuant to SSM 089-32033-00453, after completion of the WRMP project, gasoline loading at the marine dock shall be permanently ceased.

(b) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.34.3. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the operational 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 and CO for the WRMP project remain below the significant levels, rendering 326 IAC 2-3 not applicable for these pollutants.

D.34.3 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the Marine Dock shall be an affected facility for purposes of 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9– 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the Marine Dock no later than one year from the “Date of Entry” of the Consent Decree entered in Civil No. 2:12-CV-00207.

(2) The Marine Dock shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.34.4 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.34.5 Operating Requirement

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and 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.34.6 Operating Requirement

Pursuant to SSM 089-32033-00453, after cessation of gasoline loading as required by Condition D.34.2(a), naphthas, finished gasoline products, and gasoline blendstocks having a Reid Vapor Pressure of 4.0 psia or greater, shall no longer be loaded at the marine dock.

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

D.34.7 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 Requirement [326 IAC 2-7-5(3)][326 IAC 2-7-19]

D.34.8 Record Keeping Requirements

(a) To document the compliance status with Condition D.34.5 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 the compliance status with Condition D.34.3(a), the Permittee shall comply with the record keeping requirements in the LDAR Plan.

(c) Pursuant to 326 IAC 8-4-3(d) and to document the compliance status with Condition D.34.4, 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.

(d) In order to document the compliance status with Condition D.34.2, the Permittee shall maintain records of the Reid Vapor Pressure of each material loaded at the marine loading dock.

(e) To document compliance with Condition D.34.3(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(f) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (c), and (d) of this condition.

D.34.9 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.34.3(a), the Permittee shall comply with the reporting requirements in the LDAR Plan.

(b) To document compliance with Condition D.34.3(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(c) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraph (a) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a "responsible official" as defined by 326 IAC 2-7-1(35).

SECTION D.35 EMISSIONS UNIT OPERATION CONDITIONS – Hydrocarbon Flares

Emissions Unit Description:

(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)	Flare Gas Recovery System (FGRS) ID	Pilot Fuel Type
4UF Flare***	224-06	1972	H = 200 ft, D = 2.5 ft.	ARU, CFU, BOU, 4UF	15,000	FGRS4**** (installed as part of the FGR Project)	Fuel Gas and Natural Gas
FCU flare***	230-02	1945	H = 200 ft. D = 2.0 ft.	FCU 600	5620	FGRS3**** (installed as part of the FGR Project)	Fuel Gas and Natural Gas
UIU Flare***	220-04	1958	H = 199.5 ft. D = 2.5 ft.	ISOM, 3UF, 2TP, CRU	7550	FGRS4**** (installed as part of the FGR Project)	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	FGRS3**** (installed as part of the FGR Project)	Fuel Gas and Natural Gas
Alky Flare***	140-01	1961	H = 199.5 ft D = 2.5 ft.	PCU, Alky	3920	FGRS3**** (installed as part of the FGR Project)	Fuel Gas and Natural Gas
SRU Flare*****	162-03	1971	H = 300 ft. D = 1.5 ft.	SRU	688	none	Fuel Gas and Natural Gas
DDU Flare	698-02	1993	H = 200 ft. D = 1.5 ft.	DDU, HU, Coker, DHT	6000	none	Fuel Gas and Natural Gas
LPG Flare	604-01	1986	H = 50 ft. D = 1.2 ft.	LPG storage vessels and loading facilities	30	none	LPG
PIB Flare**	2	1982	H = 250 ft. D = 3.0 ft.	RGP/PGP Loading Rack	540,000 lb/hr	none	Fuel Gas and Natural Gas
GOHT Flare***	802-03	Installed as Part of WRMP	H = 316 ft. D = 5 ft	GOHT	N/A	FGRS2 (installed as part of WRMP)	Natural Gas
South Flare***	800-04	Installed as Part of WRMP	H = 350 ft. D = 6 ft	Coker 2, 12PS, Sulfur Recovery Complex, VRU 300, VRU 400	N/A	FGRS1 (installed as part of WRMP)	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). This unit has been permanently decommissioned.
*** - Flares are equipped with a flare gas recovery system. Under normal operation the recovered gas streams will be utilized in the refinery fuel gas

system.

**** - Note that FGRS3 and FGRS4 are cross connected via a tie-line, to maximize gas recovery and use of available compressor capacity as needed.

*****As specified by the Federal Consent Decree from *United States, et al. v BP Products North America Inc*, Civil No. 2:12-CV-00207 (N.D. Ind. Hammond Div., May 23, 2012), the SRU Flare was permanently decommissioned on August 12, 2013 by the installation of a welded blind on the piping.

Additionally, the following emission units are associated with the flare gas recovery systems: Associated valves, pumps, compressors (FGRS 1: K-103A and K-103B; FGRS 2: K-946A and K-946B; FGRS 3: K-281, K-282, K-283, and K-284; FGRS 4: K-291, K-292, and K-293), pressure relief devices, sampling connection systems, open ended lines or valves, flanges or other connectors, instrumentation, and sewer components.

(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 2-1.1-4] Emission Offset [326 IAC 2-3], and Sulfur Dioxide [326 IAC 7-4.1] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, 326 IAC 2-3, and 326 IAC 7-4.1 not applicable, the Permittee shall comply with the following for the GOHT Flare and the South Flare:

(a) The emissions of NO_X 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 SO_2 shall not exceed 0.6 pounds per million cubic feet of pilot gas burned.

(e) The emissions of SO_2 shall not exceed 0.6 pounds per million cubic feet of purge gas burned.

(f) The emissions of PM and PM-10 each shall not exceed 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	37,374
South flare-pilot	3,679.2
South flare-purge	42,198

(h) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

(i) Pursuant to SSM 089-32033-00453, the Permittee shall use only natural gas for pilot and purge gas for the GOHT and South Flares.

Compliance with the fuel usage limits and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.35.2 Sulfur Dioxide Limitations [326 IAC 7-4.1-1]

Pursuant to 326 IAC 7-4.1-1 (Lake County Sulfur Dioxide Emission Limitations), the 4UF, FCU, UIU, VRU, Alky, and DDU flares shall only burn natural gas for pilot.

D.35.3 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2(a), the particulate matter emissions from the flares 4UF, FCU, UIU, VRU, Alky, DDU, LPG, GOHT, and South shall each be limited to 0.03 grains per dry standard cubic foot.

D.35.4 Equipment Leaks of VOC [326 IAC 12][40 CFR 60, Subpart GGGa]

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the Permittee shall comply with the control device standards pursuant to 40 CFR 60, Subpart GGGa, specified in Section F.9, for the LPG flare.

(b) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the South & GOHT Flare Gas Recovery Systems are affected facilities pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the South & GOHT flare gas recovery systems no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.35.5 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.

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

D.35.6 Record Keeping Requirements

(a) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Condition D.35.4, the Permittee shall maintain the records as specified in Section F.9.

(b) To document the compliance status with Condition D.35.8 Paragraphs 69 and 70, the Permittee shall keep records as specified in Section F.3.

(c) In order to document the compliance status with Condition D.35.1(g), the Permittee shall maintain records of fuel usages at the GOHT and South flares.

(d) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraph (c) of this condition.

D.35.7 Reporting Requirements

(a) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Condition D.35.4, the Permittee shall submit reports as specified in Section F.9.

(b) To document the compliance status with Condition D.35.9 Paragraphs 69 and 70, the Permittee shall submit to IDEM, OAQ the reports specified in Section F.3.

(c) In order to document the compliance status with Condition D.35.1, the Permittee shall submit quarterly reports for pilot gas and purge gas usages at the GOHT and South flares.

(d) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraph (c) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

D.35.8 Consent Decree (Civil No. 2:12-CV-00207) Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, the Permittee shall comply with the following Paragraphs of the Consent Decree: (As specified by Consent Decree entered in Civil No. 2:12-CV-00207, in each of the following paragraphs, “Covered Flare” shall mean each of the following Elevated, Steam-Assisted Flares at the Refinery: VRU Flare, FCU Flare, Alky Flare, 4UF Flare, UIU Flare, South Flare, GOHT Flare and the DDU Flare.)

B. Instrumentation and Monitoring Systems for Covered Flares

6. Installation and Operation of Monitoring Systems.

a. By no later than startup of the South Flare, and December 31, 2013 for all other Covered Flares, BPP shall have completed the installation and commenced the operation of the instrumentation, controls, and monitoring systems set forth in Paragraphs 7 - 13.

b. BPP may elect to re-position or upgrade the existing Panametric flow meters on the DDU, VRU, FCU, Alky, 4UF and UIU Flares in order to meet the accuracy requirement in Appendix FLR-11. BPP shall complete any such upgrades or re-positioning by December 31st of the following years:

Covered Flare	Re-position or Upgrade Panametric Flow Meter
DDU	2014
FCU	2014
VRU	2015
Alky	2016
4UF	2016
UIU	2017

7. Vent Gas Flow Monitoring System. By means of this system, BPP shall determine the Vent Gas Volumetric and Mass Flow Rates at each Covered Flare. This system shall:

   a. Continuously measure the total flow, in scfm or pounds per hour, of the gas flowing through it;

   b. Continuously analyze pressure and temperature at each point of flow measurement;

   c. Have dual channel measurement at each point of flow measurement for flow meters using an ultrasonic flow measurement method; and

   d. Have retractable or removable sensors at each point of flow measurement to ensure that the flow meter is maintainable online.

   Prior to any necessary relocation of the Panametrics flow meter pursuant to Paragraph 6, the Vent Gas Flow Monitoring System shall consist of (1) an ultrasonic flow meter that is measuring the flow of gas in the header prior to the flare stack but after any installed flare stack (after all addition of Waste Gas from process units) or in the flare stack; (2) a flow meter measuring any Supplemental Gas that may be supplied to the flare stack and that is not already measured by the ultrasonic flow meter; and (3) a flow meter measuring any Purge Gas that may be supplied to the flare stack and that is not already measured by the ultrasonic flow meter. After the relocation of the ultrasonic flow meter pursuant to Paragraph 6, the Vent Gas Flow Monitoring System shall consist of (1) an ultrasonic flow meter that is measuring the flow of gas in the header prior to the water seal and after any FGRS; (2) a flow meter measuring any Supplemental Gas that may be supplied to the flare stack and that is not already measured by the ultrasonic flow meter; and (3) a flow meter measuring any Purge Gas that may be supplied to the flare stack and that is not already measured by the ultrasonic flow meter. In all cases, the system, in its complete configuration, shall accurately measure Volumetric Vent Gas Flow Rate as defined by this Appendix.

8. Vent Gas Average Molecular Weight Analyzer. By means of this system, BPP shall determine the average Molecular Weight of the Vent Gas at each Covered Flare. BPP shall utilize the molecular weight analyzer in the ultrasonic flow meter at each Covered Flare to determine the molecular weight of the gas flowing to each such flow meter. BPP shall assume a constant molecular weight for the Purge Gas and Supplemental Gas that is representative of the molecular weight of natural gas supplied from the local gas company (NIPSCO) at each Covered Flare.

9. Total Steam Flow Monitoring System. This system shall:

   a. Continuously measure the flow, in scfm and pounds per hour, of the Total Steam to the Covered Flare; and

   b. Continuously analyze the pressure and temperature of steam at a representative point of steam flow measurement.

10. Steam Control Equipment. This equipment, including, as necessary, main and trim control valves and piping, shall enable BPP to control steam flow in a manner sufficient to ensure compliance with this Decree.

11. Gas Chromatograph (“GC”). This instrument shall be capable of speciating the gas constituents set forth in Appendix FLR-10. For all constituents except Hydrogen Sulfide (“H2S”), the GC shall measure the concentration on a mole percent (“mol/mol%”) basis; for H2S, the GC shall measure the concentration on a parts per million volume basis (“ppmv”).

12. Meteorologic Station or “Met Station” (for the Refinery, not each Covered Flare). This station shall include meteorologic data instruments capable of measuring wind speed. The station shall be located in the refinery at Gate 36.

13. Video Camera. This instrument shall record, in digital format, the flame of, and any Smoke Emissions and/or Wake Dominated Flow from, each Covered Flare.

15. Instrumentation and Monitoring Systems: Specifications. The instrumentation and monitoring systems identified in Paragraphs 7 – 9 and 11 - 12 shall meet or exceed the specifications set forth in Appendix FLR-11.

16. Instrumentation and Monitoring Systems: Recording and Averaging Times. The instrumentation and monitoring systems identified in Paragraphs 7 – 9 and 11 - 13 shall be able to produce and record data measurements and calculations for each parameter at the following time intervals:

Instrumentation and Monitoring System	Recording and Averaging Times
Vent Gas Flow; Vent Gas Average Molecular Weight; Total Steam Flow; Pilot Gas Flow (if installed)	Measure continuously and record 5 minute block averages
Gas Chromatograph	Measure no less than once every 15 minutes and record that value
Wind Speed	Measure continuously and record 5 minute block averages
Video Camera	Record at a rate of no less than 4 frames per minute

17. Instrumentation and Monitoring Systems: Operation and Maintenance. BPP shall operate each of the instruments and monitoring systems required in Paragraphs 7 - 9, 11 - 13, and 42.a and 42.b on a continuous basis except for the following periods:

    a. Malfunction of an instrument and/or monitoring system;

    b. Maintenance following instrument Malfunction;

    c. Scheduled maintenance of an instrument in accordance with the manufacturer’s recommended schedule;

    d. Quality Assurance/Quality Control activities; and/or

    e. When the Covered Flare that the instrument or monitoring system is associated with is not in service.

    Provided however, that in no event shall the excepted activities in Subparagraphs 17.a—17.c for any instrument exceed 110 hours in any calendar quarter. The calculation of instrument downtime shall be made in accordance with 40 C.F.R. § 60.13(h)(2) and Paragraph VI of Appendix FLR-11. If the excepted activities in Subparagraphs 17.a—17.c exceed 110 hours in any calendar quarter, EPA shall be entitled to seek stipulated penalties under Paragraph 150.j of Part X (“Stipulated Penalties”) and BPP shall be entitled to assert that the period of instrumentation and monitoring system downtime was justified under the circumstances. Nothing in this Paragraph is intended to prevent BPP from claiming a force majeure defense to any period of instrumentation and/or monitoring system downtime. Nothing in this Paragraph supersedes or replaces the monitoring requirements, including operation, maintenance, and quality assurance/quality control requirements, of 40 C.F.R. Part 60, Subparts J and Ja (including monitoring requirements in 40 C.F.R. Part 60, Subpart Ja that may be stayed as of the Date of Lodging of this Consent Decree but may become effective after the Date of Lodging) at such time as those requirements become applicable pursuant to Paragraphs 69 and 70. All such requirements shall apply in accordance with the terms set forth in 40 C.F.R. Part 60, Subparts J and Ja.

D. Flare Gas Recovery Systems for all Covered Flares Except the DDU Flare

23. Dates of Installation and Commencement of Operation of Flare Gas Recovery Systems

a. Except as specifically provided in Subparagraph 23.b, by no later than the following dates for the following Covered Flares or groups of Covered Flares, BPP shall complete installation and commence operation of the following Flare Gas Recovery Systems:

ID	Covered Flares	Date
FGRS 1	South Flare	Upon startup of South Flare
FGRS 2	GOHT	Upon startup of GOHT Flare
FGRS 3	VRU, FCU, Alky	December 31, 2015
FGRS 4	4UF, UIU	December 31, 2016

b. BPP shall complete the tie-in of the Alky Flare to FGRS 3 by no later than December 31, 2016, and commence recovery of Waste Gas by that time.

Note: This Paragraph (D.23.a) was not required to be placed in a Part 70 operating permit pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207; however, the requirement is specified in the Consent Decree entered in Civil No. 2:12-CV-00207.

25. Operation of Flare Gas Recovery Systems. Each Flare Gas Recovery System shall be operated in a manner to minimize Waste Gas to the Flares while ensuring safe refinery operations. BPP shall operate the equipment consistent with good engineering and maintenance practices and in accordance with the manufacturer’s specifications.

a. Each compressor shall be capable of starting automatically from an idle mode in a time period and manner consistent with the manufacturer’s specifications when necessary to process additional Waste Gas. BPP shall equip the compressors with automatic startup capability by no later than the following dates:

ID	Covered Flares	Date
FGRS 1	South Flare	December 31, 2015
FGRS 2	GOHT	December 31, 2015
FGRS 3	VRU, FCU, Alky	Upon startup of FGRS 3
FGRS 4	4UF, UIU	Upon startup of FGRS 4

b. A compressor in a standby mode and capable of automatic startup shall be considered to be available for operation. Once the compressors at the applicable FGRS are capable of automatic startup as specified in subparagraph 25.a., the FGRS shall have the following number of compressors available for operation at least 95% of the time, based on an 8760-hour rolling average, rolled hourly:

No. of Compressors that must be available ID	Covered Flares	at least 95% of the time
FGRS 1	South Flare	1
FGRS 2	GOHT	1
FGRS 3	VRU, FCU, Alky	3
FGRS 4	4UF, UIU	2

Each FGRS shall be designed to automatically startup available compressors to process surplus Waste Gas until all available compressors are in operation, including times when a FGRS has all of its installed compressors available for operation. Prior to the installation of automatic startup at FGRS 1 and FGRS 2, BPP shall start compressors manually from standby mode to process surplus Waste Gas within one hour.

c. Additional Requirements Applicable to FGRS 3 and 4

i. At all times, except during the periods described in subparagraphs iii or iv below, BPP shall have one compressor in operations at FGRS 3 and at least one additional compressor either in operation or in a standby mode and capable of automatic startup.
ii. At all times, except during the periods described in subparagraphs iii or iv below, BPP shall have one compressor in operation at FGRS 4.
iii. The requirements of subparagraphs i and ii shall not apply to an FGRS during periods of maintenance on common equipment within that FGRS. These periods of maintenance shall not exceed 336 hours per FGRS on a five year rolling average period, rolled daily. BPP will make best efforts to schedule these maintenance activities during process unit turnarounds and to minimize the generation of Waste Gas during such periods.
iv. The requirements of subparagraph i and ii shall not apply during periods when compressors are shut down consistent with the manufacturer's specifications or good engineering practices to preserve the mechanical integrity of the compressors (for example, as a result of high pressure or temperature).

E. Limitations on Flaring

26. Limitations on Flaring: Initial Limit. By no later than December 31, 2018, BPP shall comply with the following limitations on flaring at the Refinery:

a. From all Covered Flares and the LPG Flare, BPP shall not flare more than 3.1 MMscfd of Waste Gas on a 30-day rolling average basis, rolled daily; and

b. From all Covered Flares and the LPG Flare, BPP shall not flare more than 2.1 MMscfd of Waste Gas on a 365-day rolling average basis, rolled daily.

Each exceedance of the 30-day rolling average limit or each exceedance of the 365-day rolling average limit shall constitute one day of violation. An exceedance of either or both of the limits shall not prohibit ongoing refinery operations.

27. Limitations on Flaring: Requesting an Increase in the Limit.

a. Once per calendar year commencing no sooner than January 2019, BPP may submit a request to EPA to increase the limitations on flaring set forth in Subparagraphs 26.a and/or 26.b. Any request for an increase in the limitations on flaring shall be based upon an increase in crude capacity that is due to a post-WRMP permitted modification. In any such request, BPP shall propose (a) new limit(s) based upon the following equations:

i. For the Refinery-wide, 30-day rolling average limit:

Refinery Flaring ≤ 750,000 scfd x Whiting Crude Cap.x Whiting Complexity 100,000 bpd Industry Avg Complexity

ii. For the Refinery-wide, 365-day rolling average limit:

Refinery Flaring ≤ 500,000 scfd x Whiting Crude Cap.x Whiting Complexity 100,000 bpd Industry Avg Complexity

b. For purposes of Subparagraph 27.a:

   i. The items in italics are variables that will change over time.
   ii. The Whiting Crude Capacity shall be based on the projected capacity of the Refinery, as reported annually by BPP to the Department of Energy for the year of the request date.
   iii. The Whiting Complexity shall be calculated in accordance with Equation 1 of Appendix FLR-14. The crude capacity will be the capacity reported by BPP to the Department of Energy for the year that the limit will be in effect. The process unit capacities will be the capacities published the Oil & Gas Journal in barrels per calendar day for the year that the limit will be in effect. BPP shall certify the accuracy of the process unit capacities used to support any request for a change to the limitations on flaring.
   iv. The *Industry Average Complexity* shall be calculated in accordance with Equation 2 of Appendix FLR-14.

c. EPA Response to Request. EPA shall evaluate any request under Subparagraph 27.a on the basis of consistency with Subparagraphs 27.a and 27.b. If EPA does not act on BPP's request within 90 days of submission, BPP may invoke the dispute resolution provisions of this Decree. The new limit(s) shall take effect, if ever, beginning on the date that EPA approves the request or a dispute is resolved in BPP's favor. Nothing in this Consent Decree shall be construed to relieve BPP of an obligation to evaluate, under applicable Prevention of Significant Deterioration and Nonattainment New Source Review requirements, any increase in a Refinery-Wide Limit on Flaring.

28. <u>Meaning and Calculation of "Waste Gas" Flow for Purposes of the Limitation on Flaring</u>. For purposes of the meaning and calculation of "Waste Gas" flow in the limitations on flaring in Paragraphs 26 and 27, the following shall apply:

a. To the extent that BPP has instrumentation capable of measuring the volumetric flow rate of hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) in the Waste Gas, the contribution of all measured flows of any of these elements/compounds may be excluded from the Waste Gas flow rate calculation.

b. Waste Gas flows during all periods (including but not limited to normal operations and periods of startup, shutdown, Malfunction, process upsets, relief valve leakages, power losses due to an interruptible power service agreement, and emergencies arising from events within the boundaries of the Refinery), except those expressly described in Subparagraph 28.c and/or the next sentence, shall be included. Waste Gas flows that could not be prevented through reasonable planning and are caused by a natural disaster, act of war or terrorism, or External Power Loss may be excluded from the calculation of flow rate.

c. By no later than 180 days prior to a Cold Startup of the Refinery, BPP may submit to EPA a plan to minimize Waste Gas flaring during a Cold Startup of the Refinery ("Cold Startup Waste Gas Minimization Plan"). If BPP submits a Cold Startup Waste Gas Minimization Plan and operates in accordance with it, BPP may exclude, from the Refinery-Wide 30-day rolling average limit, Waste Gas flows during any Cold Startup that occurs more than 180 days after submission of the Cold Startup Waste Gas Minimization Plan. BPP may not exclude any such flows from the refinery-wide 365-day rolling average limit.

d. Except for hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or water (steam) contributions to the flow rate that are excluded by virtue of instrumentation measuring these flows, by no later than thirty days after the occurrence of any flow that is not included in a computation, BPP shall submit a written report to EPA that specifically identifies the event that resulted in the exclusion. If the event is a Cold Startup of the Refinery, BPP shall describe dates, durations, and volumes of the flows during the Cold Startup as well as the steps BPP took in compliance with the Cold Startup Waste Gas Minimization Plan. If the event is anything other than a cold startup, BPP shall describe the following: the date(s) and duration(s) of the flows caused by the event; the estimated VOC emissions during the event; whether flows from the event are anticipated to persist after the notice, and if so, for how long; and the measures taken or to be taken to prevent or minimize the flows, including, for future anticipated flow, the schedule by which those measures will be implemented.

F. Flare Combustion Efficiency Requirements for Covered Flares

29. Emission Standards and Work Practices Applicable to each Covered Flare upon the "Date of Entry". By no later than the "Date of Entry", BPP shall comply with the following requirements at each Covered Flare:

a. Operation during Emissions Venting. BPP shall operate each Covered Flare at all times when emissions may be vented to it.

b. No Visible Emissions. Except for periods of Startup, Shutdown, and/or Malfunction, BPP shall operate each Covered Flare with no Visible Emissions. Method 22 in 40 Part 60, Appendix A, shall be used to determine compliance with this standard. However, for purposes of this Appendix, Visible Emissions may be determined by either a person certified pursuant to Method 22 or by a video camera.

c. Flame Presence. Except for periods of Malfunction of the Flare, BPP shall operate each Covered Flare with a flame present at all times. BPP shall monitor the presence of the pilot flame using a thermocouple or any other equivalent device to detect the presence of the pilot flame.

d. Exit Velocity. Except for periods of Startup, Shutdown, and/or Malfunction, BPP shall operate each Covered Flare with an Exit Velocity less than 18.3 m/sec (60 ft/sec) on a one-hour block average; provided however, that:

i. If any Covered Flare combusts Vent Gas with a Net Heating Value of greater than 1000 BTU/scf, BPP may operate the Covered Flare with an Exit Velocity equal to or greater than 18.3 m/sec (60 ft/sec) but less than 122 m/sec (400 ft/sec) on a one-hour block average; and
ii. If any Covered Flare has a maximum permitted velocity (V_{max}), BPP may operate the Covered Flare with an Exit Velocity less than V_{max} provided that it also operates the applicable Flare with an Exit Velocity of less than 122 m/sec (400 ft/sec) on a one-hour block

Vmax shall be calculated in accordance with 40 C.F.R. § 60.18(f)(5). The Unobstructed Cross Sectional Area of the Flare Tip shall be calculated consistent with Appendix FLR-6.

e. Monitoring According to Applicable Provisions. BPP shall comply with all applicable Subparts of 40 C.F.R. Parts 60, 61, or 63 that state how a particular Covered Flare must be monitored.

f. Good Air Pollution Control Practices. At all times, including during periods of Startup, Shutdown, and/or Malfunction, BPP shall implement good air pollution control practices to minimize emissions from each Covered Flare; provided however, that BPP shall not be in violation of this requirement for any practice that this Consent Decree requires BPP to implement after the Date of Lodging for the period between the Date of Lodging and the implementation date or compliance date (whichever is applicable) for the particular practice.

30. Work Practice Standards for each Covered Flare.. By no later than January 31, 2014, for all Covered Flares utilizing the instrumentation and controls required to be installed pursuant to Paragraphs 7 – 13, BPP shall install and operate on each Covered Flare an Automatic Control System that shall:

a. automate the control of the Supplemental Gas flow rate to the respective Flare; and

b. automate the control of the Total Steam Flow Rate to the respective Flare.

31. Exception to Part of the Work Practice Standards in Subparagraph 30.b. BPP manually may override the operation of the Automatic Control System required in Subparagraph 30.b (for control of Total Steam Mass Rate) if the exception in Paragraph 51 applies and/or in order to achieve the following:

a. Stop Smoke Emissions that are occurring;

b. Meet the Net Heating Value requirements of Paragraph 33;

c. Prevent extinguishing the Flare;

d. Protect personnel safety;

e. Stop Discontinuous Wake Dominated Flow; and/or

f. During Startup, Shutdown, or Malfunction of a process unit that feeds the Covered Flare.

32. Operation According to Design. By no later than December 31, 2014, for all Covered Flares, BPP shall operate and maintain each Covered Flare in accordance with its design, except if, and only to the extent that, operation and maintenance of the Covered Flare in conformance with its design conflicts with compliance with one or more of the requirements of this Appendix.

33. Net Heating Value Standards for each Covered Flare

b. *NHVcz-limit*. By no later than December 31, 2014, for all Covered Flares, and except as provided in Paragraph 51, BPP shall calculate an *NHVcz-limit* at each Covered Flare no less than every fifteen minutes. Except as provided in Paragraph 51, BPP shall operate each Covered Flare so as to ensure that the Covered Flare's *NHVcz*, on a three-hour rolling average basis, rolled every fifteen minutes, is greater than or equal to its *NHVcz-limit* on a three-hour rolling average basis, rolled every fifteen minutes. BPP shall utilize the equations and directives set forth in Appendix FLR-3 to meet the requirements of this Subparagraph.

34. *S/VG* Standards.

a. By no later than December 31, 2014, for all Covered Flares, BPP shall operate each Covered Flare at less than or equal to an *S/VG* of 3.0 on a one-hour rolling average, rolled every five minutes.

b. Exceptions. Notwithstanding the requirements of Subparagraph 34.a, BPP is not subject to the emissions standard in that Subparagraph if the exception in Paragraph 51 applies and/or in order to achieve the following:

i. Stop Smoke Emissions that are occurring;
ii. Meet the Net Heating Value requirements of Paragraph 33;
iii. Prevent extinguishing the Flare; and/or
iv. Protect personnel safety.

35. Prohibition on Discontinuous Wake Dominated Flow or Requirement for Minimum *MFR* for Covered Flares.

a. By no later than December 31, 2014, for all Covered Flares, BPP shall comply with either Subparagraph 35.b. or 35.c. In the first semi-annual report due after the applicable compliance date, BPP shall identify which compliance option it selects for each Covered Flare. BPP may select different alternatives for different Covered Flares and may change its election for any given Covered Flare by providing EPA with 30 days prior notice of the change.

b. Prohibition on Discontinuous Wake Dominated Flow.

   i. BPP shall not operate the Covered Flares with Discontinuous Wake Dominated Flow, except for periods not to exceed a total of five minutes during any two consecutive hours. BPP shall add Supplemental Gas as necessary to prevent such instances of Discontinuous Wake Dominated Flow at the Covered Flares.
   ii. Prior to the effective date of the prohibition in Subparagraph 35.b.i, for all operators and supervisors with responsibility and/or oversight for the operation of each Covered Flare, BPP shall complete training on the meaning and prevention of Discontinuous Wake Dominated Flow. After the effective date, operators shall monitor the operation of each Covered Flare at intervals appropriate for the weather conditions and service of the Covered Flare in order to comply with the prohibition in Subparagraph 35.b.i.

c. MFR Requirements. MFR shall be calculated in accordance with the equations, conversion factors, MFR constants, MFR measured variables, and MFR calculated variables set forth in Appendix FLR-5. BPP shall either:

   i. Maintain a minimum MFR of 0.0030 on a 60 minute rolling average basis, rolled every 5 minutes, at each Covered Flare; or
   ii. Propose a Flare-specific MFR. BPP shall submit such a proposal to EPA for approval. In any such proposal, BPP shall demonstrate, using, at a minimum, photographs correlated to MFR, that at the proposed MFR, Discontinuous Wake Dominated Flow will not occur for the Covered Flare that is the subject of the request. d. Notwithstanding Subparagraphs 35.b and c., BPP shall not be required to add Supplemental Gas at any time that the wind speed at the Refinery is greater than or equal to 35 mph on a 60-minute rolling average basis, rolled every 5 minutes, and/or if the exception in Paragraph 51 applies.

36. 98% Combustion Efficiency. By no later than December 31, 2014, for all Covered Flares, BPP shall operate each Covered Flare with a minimum of a 98% Combustion Efficiency at all times when Waste Gases are vented to it. To demonstrate continuous compliance with the 98% Combustion Efficiency, BPP shall operate each Covered Flare within the range of operating parameters set forth in Paragraphs 33 – 35.

37. Inapplicability of Paragraphs 33 – 36. The requirements of Paragraphs 33 – 36 are not applicable to any Covered Flare when the only gas or gases being vented to the Covered Flare is/are Pilot Gas and/or Purge Gas. Pilot Gas and Purge Gas will be considered to be the only gases being vented to those Flares if both of the following conditions are met for the water seal drum that is part of the FGRS associated with the respective Covered Flare:

   a. The pressure difference between the inlet pressure and outlet pressure is less than the water seal pressure as set by the static head of water between the opening of the dip tube in the drum and the level-setting weir in the drum; and

   b. The water level in the drum is at the level of the weir.

41. Recordkeeping: Timing and Substance. BPP shall comply with the following recordkeeping requirements:

a. By no later than March 31, 2014, for all Covered Flares, BPP shall calculate and record, in accordance with the recording and averaging times required in Paragraph 16, each of the following parameters:

   i. Total Steam Volumetric Flow Rate (in scfm) and Total Steam Mass Flow Rate (in lb/hr)
   ii. Vent Gas Flow and Mass Rates (in scfm and lb/hour)
   iii. S/VG (in lbs steam/lbs Vent Gas)
   iv. NHVvg (in BTU/scf)
   v. NHVcz (in BTU/scf)
   vi. NHVcz-limit (in BTU/scf)

b. By no later than June 30, 2014, for all Covered Flares, commencing if and when any instrument subject to Paragraph 17 operates at less than 95% in any calendar quarter of the in-service time of the Covered Flare that is being monitored by the respective instrument, BPP shall record the duration of the deviation, an explanation of the cause(s) of the deviation, and a description of the corrective action(s) that BPP took.

c. By no later than January 31, 2014, for all Covered Flares, for compliance with the work practice standards in Paragraph 30: (i) BPP shall record each time it manually overrides its Automatic Control System, including the date, time, duration, reason for the override, and corrective actions that BPP took; and (ii) where the reason for the override was to stop Smoke Emissions that were occurring, BPP shall include a copy of the digital video record (with a time stamp) of the Covered Flare during the period of the manual override.

d. At any time that BPP deviates from the standards in Paragraphs 29, 33 - 36, after the effective date of those standards, BPP shall record the duration of the deviation, an explanation of the cause(s) of the deviation, and a description of the corrective action(s) that BPP took.

e. Recordkeeping: Document Retention. For purposes of this Appendix, and except with respect to the data produced by video cameras required pursuant to Paragraph 13, BPP shall retain all records created pursuant to this Appendix, including the raw data values, in accordance with Part VIII ("Reporting and Recordkeeping") and shall make any such documents available to EPA upon request. BPP shall retain the data recorded by the Video Cameras required pursuant to Paragraph 13 for six months except that BPP shall comply with the data retention requirements in Part VIII for those periods when BPP overrode the Automatic Control System.

G. LPG Flare Requirements

42. LPG Flare Requirements: Instrumentation and Monitoring Systems. By no later than one year after the Date of Entry, BPP shall undertake the following for the LPG Flare:

a. Install a flow meter in order to determine the Vent Gas Volumetric and Mass Flow Rates to the LPG Flare. The air flow rate shall be determined from the fan speed on the Assist Air blower.

b. Install a Variable Speed Motor on the LPG Flare's Assist Air blower;

c. Install a control system that will automate the control of the Variable Speed Motor on the LPG Flare's Assist Air blower to enable BPP to comply with the standard set forth in Paragraph 45; and

d. In the semi-annual report required under Paragraph 98 of Part VIII that is the first one due after one year after the Date of Entry of this Consent Decree, provide a detailed description of the installations made in compliance with Subparagraphs 42.a. and 42.b, including the specific models and manufacturers.

44. Emission Standards Applicable to the LPG Flare. By no later than one year after the Date of Entry, BPP shall comply with each of the requirements in Paragraph 29 at the LPG Flare, except that, with respect to Exit Velocity, BPP shall comply with the requirements in 40 C.F.R. § 60.18(c)(5) and not those in Subparagraph 29(d).

45. Standard for $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$. By no later than one year after the Date of Entry of this Consent Decree and continuing through to either: (i) the date that EPA sets a new limit pursuant to either Subparagraph 48.d or 49.b; or (ii) the termination of this Consent Decree, whichever is applicable, BPP shall operate the LPG Flare so as to ensure that $\dot{m}_{air\text{-}asst} < 10 \times \dot{m}_{air\text{-}stoich\text{-}vg}$, on a one-hour rolling average, rolled every five minutes. BPP shall utilize the equations and directives set forth in Appendix FLR-15 to meet the requirements of this Paragraph. Notwithstanding the requirements of this Paragraph, BPP is not subject to the standard set forth in this Paragraph if the exception in Paragraph 51 applies and/or in order to (1) stop Smoke Emissions that are occurring, (2) prevent extinguishing the Flare, (3) protect personnel safety, and /or (4) prevent Wake Dominated Flow.

46. Operation According to Design. By no later than one year after the Date of Entry of this Consent Decree, BPP shall operate and maintain the LPG Flare in accordance with its design, except if, and only to the extent that, operation and maintenance of the LPG Flare in conformance with its design conflicts with compliance with one or more of the requirements of this Appendix.

48. Testing Depending on Annual Average Vent Gas Volumetric Flow Rate to the LPG Flare: Consequences if the Annual Average Vent Gas Flow Rate for 2015 for the LPG Flare Equals or Exceeds Certain Figures.

    d. EPA-Established Operating Limits and Combustion Efficiency. Based on all of the available information from the testing conducted pursuant to Subparagraph 48.a and the report submitted pursuant to Subparagraph 48.b, EPA shall establish a $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$ that will enable BPP to achieve a Combustion Efficiency as high as reliably obtainable. EPA also shall establish a Combustion Efficiency for the LPG Flare that is reliably obtainable, but shall be no higher than 98%. Within 60 days of receiving written notice establishing such limits, BPP shall comply with the $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$ and Combustion Efficiency established by EPA.

    e. Exceptions to Compliance with Limits in Subparagraphs 48.c and 48.d. BPP shall not be subject to the limits in Subparagraphs 48.c. or 48.d if the exception in Paragraph 51 applies and/or in order to achieve the following:

        (1) Stop Smoke Emissions that are occurring;
        (2) Meet Net Heating Value requirements;
        (3) Prevent extinguishing the Flare; and/or
        (4) Protect personnel safety.

H. Exception for Instrument Downtime

51. A failure to comply with the work practices or standards in Paragraphs 30.b, 33.a, 33.b, 34.a, 35.b, 35.c, 45, 48.c, or 48.d shall not constitute a violation of such work practice or standard if the noncompliance results from downtime of instruments or equipment due to the following:

    a. Malfunction of an instrument, for an instrument needed to meet the requirement(s);

    b. Maintenance following instrument Malfunction, for an instrument needed to meet the requirement(s);

c. Scheduled maintenance of an instrument in accordance with the manufacturer's recommended schedule, for an instrument needed to meet the requirement; and/or

d. Quality Assurance/Quality Control activities on an instrument needed to meet the requirement.

Provided, however, that this exception shall no longer be applicable if the activities in Subparagraphs 51a. through d. exceed 110 hours in any calendar quarter for any instrument. The calculation of instrument downtime shall be made in accordance with 40 C.F.R. § 60.13(h)(2) and Paragraph VI of Appendix FLR-11.

K. Miscellaneous

67. Temporary-Use Flares.

a. Applicability.
The provisions of this Paragraph shall apply to Temporary-Use Flares.

b. Distinction between Planned and Unplanned Outages of Covered Flares.
For purposes of this Paragraph, a "planned" outage of a Covered Flare shall mean an outage that is scheduled 30 days or more in advance of the outage. An "unplanned" outage is an outage that either is scheduled less than 30 days in advance or is unscheduled.

c. 504 hours or less.
For any planned or unplanned outage of a Covered Flare that BPP knows or reasonably anticipates will result in 504 hours or less of downtime on a rolling 1095 day average period, BPP shall make good faith efforts to ensure that the Temporary-Use Flare that replaces the Covered Flare complies with all of the requirements of this Consent Decree that are applicable to the Covered Flare that the Temporary-Use Flare replaces.

d. More than 504 hours.

i. Planned.
For any planned outage of a Covered Flare that BPP knows or reasonably can anticipate will last 504 hours or more on a rolling three-year average period, BPP shall ensure that the Temporary-Use Flare complies with all of the requirements of this Appendix related to the Covered Flare that it replaces as of the date that the Temporary-Use Flare is placed into service.

ii. Unplanned.
For any unplanned outage of a Covered Flare that, in advance of the outage, BPP cannot reasonably anticipate will last longer than 504 hours, BPP shall ensure that the Temporary-Use flare complies with all of the requirements of this Appendix related to the Covered Flare that it replaces by no later than 30 days after the date that BPP knows or reasonably should have known that the outage would last 504 hours or more.

e. Recordkeeping.
BPP shall keep records sufficient to document compliance with the requirements of this Paragraph any time it uses a Temporary-Use flare.

Note: Paragraph K.67, a., b. and e. was not required to be placed in a Part 70 operating permit pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207; however, the requirements are specified in the Consent Decree entered in Civil No. 2:12-CV-00207.

L. NSPS Subparts A, J, and Ja Applicability for Flares

69. NSPS Subparts A and J.

a. Beginning on the “Date of Entry”, and continuing until they become subject to the provision of 40 C.F.R. Part 60, Subpart Ja under Paragraph 70, the DDU and LPG Flares will each continue to be an “affected facility” within the meaning of Subparts A and J of 40 Part 60, will be subject to Subparts A and J, and will comply with the requirements of Subparts A and J, including all monitoring, recordkeeping, reporting, and operating requirements.

b. Beginning upon the date of initial startup, and continuing until they become subject to the provisions of 40 C.F.R. Part 60, Subpart Ja under Paragraph 70, the South and GOHT Flares shall each be an “affected facility” within the meaning of Subparts A and J of 40 C.F.R. Part 60. No later than 180 Days after the date of initial startup, and continuing until they become subject to the provisions of 40 C.F.R. Part 60, Subpart Ja under Paragraph 70, the South and GOHT Flares shall comply with the requirements of Subparts A and J, related to Flares, including all monitoring, recordkeeping, reporting, and operating requirements.

c. Beginning on the dates by which they are required to be tied into a FGRS under Paragraph 23 and continuing until they become subject to the provisions of 40 C.F.R. Part 60, Subpart Ja under Paragraph 70, the VRU, Alky, FCU, UIU and 4UF Flares shall each be an “affected facility” within the meaning of Subparts A and J of 40 C.F.R. Part 60, will be subject to Subparts A and J, and will comply with the requirements of Subparts A and J, including all monitoring, recordkeeping, reporting, and operating requirements.

70. NSPS Subpart Ja.

a. The DDU and the LPG Flare will each be an “affected facility” within the meaning of Subpart Ja of 40 C.F.R. Part 60, will be subject to Subpart Ja, and will comply with the requirements of Subpart Ja, including all monitoring, recordkeeping, reporting, and operating requirements, by the later of the Date of Entry or the date of compliance required by Subpart Ja when the stay of Subpart Ja no longer is in effect. The other Covered Flares will each be an “affected facility” within the meaning of Subpart Ja of 40 C.F.R. Part 60, will be subject to Subpart Ja, and will comply with the requirements of Subpart Ja, including all monitoring, recordkeeping, reporting, and operating requirements, by the later of: (i) the date by which that Flare is required to be tied into a FGRS under Paragraph 23; or (ii) the date of compliance required by Subpart Ja when the stay of Subpart Ja no longer is in effect.

b. For each Covered Flare and the LPG Flare, upon the date that each such flare becomes an “affected facility” as set forth in Subparagraph 70.a, the requirements in Sections I. and J. of this Appendix will no longer be applicable to such flare.

SECTION D.36 EMISSIONS UNIT OPERATION CONDITIONS – OSBL

Emissions Unit Description:

(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 and heat exchange systems. 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) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the OSBL is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The OSBL shall be an affected facility for purposes of 40 CFR 60, Subpart GGGa, and the Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at OSBL no later than one year from the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207.

(2) The OSBL shall not be subject to the requirements in 40 CFR § 60.482-7a(h)(2)(ii) regarding difficult-to-monitor valves.

(3) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.36.2 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.36.1. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

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 the compliance status with Condition D.36.1(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(b) To document compliance with Condition D.36.1(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(c) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraph (a) of this condition.

D.36.5 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.36.1(a), the Permittee shall submit reports as specified in the LDAR plan.

(b) To document compliance with Condition D.36.1(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(c) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraph (a) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.37 EMISSIONS UNIT OPERATION CONDITIONS – Distillate Hydrotreating Unit

Emissions Unit Description:

(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 35 mmBTU per hour and constructed in May 2005. As part of the WRMP Project, DHT Unit Heater B-601 was permanently decommissioned and a 41.9 mmBTU per hour natural gas fired heater, identified as B-601A, was constructed. 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. The DHT Heater B-601 was permanently decommissioned as of July 7, 2010.

(2) Associated valves, pumps, compressors, pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation and heat exchange 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, particulate matter emissions from Heater 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 7-4.1-1, the Permittee shall burn only natural gas in DHT Heater B-601A.

D.37.3 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR [326 IAC 2-1.1-4] and Emission Offset [326 IAC 2-3] Minor Limits

(a) In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for heater B-601A:

(1) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, the emissions of NOx shall not exceed 7.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(2) The emissions of CO shall not exceed 7.3 tons per 12 consecutive month period, with compliance determined at the end of each month.

(3) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(4) The emissions of PM and PM_{10} shall each not exceed 0.0075 pounds per million BTU.

(5) The firing rate shall not exceed 367,044 million BTU per 12 consecutive month period, with compliance determined at the end of each month.

(b) In addition, to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the heater B-601 shall be permanently shut down upon completion of the WRMP project.

(c) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.37.4. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.37.4 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the DHT is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the DHT no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.37.5 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.

The requirements in paragraphs (a) and (b) of this condition render the requirements of Emission Offset (326 IAC 2-3) not applicable.

D.37.6 Consent Decree (Civil No. 2:12-CV-00207) Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, the Permittee shall continuously operate Ultra-Low NO_X burners on DHT Heater B-601A.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, "fuel oil" shall not be burned in DDU Heater B-601A.

Compliance Determination Requirements

D.37.7 Performance 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) Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the DHT Heater B-601A, the Permittee shall perform PM, PM10, and VOC testing of DHT Heater B-601A utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.37.8 Continuous Emissions Monitoring

The CO and NO_X Continuous Emissions Monitors (CEMs) for DHT Heater B-601A shall be calibrated, maintained, and operated for measuring CO and NO_X in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - 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 the compliance status with Condition D.37.4(a), the Permittee shall keep records as specified in the LDAR plan.

(b) In order to document the compliance status with Condition D.37.3, the Permittee shall maintain records of the monthly firing rates at B-601A.

(c) Pursuant to 326 IAC 3-5-6 and to document the compliance status with Condition D.37.9, 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) To document compliance with Condition D.37.4(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(e) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), and (c) of this condition.

D.37.11 Reporting Requirements

(a) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.37.4(a), the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(b) In order to document the compliance status with Condition D.37.3, the Permittee shall submit a quarterly summary of the monthly firing rates at heater B-601A not later than thirty (30) days after the end of the quarter being reported.

(c) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.37.3 and D.37.9, the Permittee shall submit reports of excess CO and NO_X emissions not later than 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

(d) To document compliance with Condition D.37.4(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(e) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (b), and (c) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.38 EMISSIONS UNIT OPERATION CONDITIONS – Degreasing

Emissions Unit Description:

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]

(a) Pursuant to 326 IAC 8-3-2(a) (Cold Cleaner Degreaser Control Equipment and Operating Requirements), for cold cleaning operations constructed after January 1, 1980, the Permittee shall:

(1) Equip the degreaser with a cover.

(2) Equip the degreaser with a device for draining cleaned parts.

(3) Close the degreaser cover whenever parts are not being handled in the degreaser.

(4) Drain cleaned parts for at least fifteen (15) seconds or until dripping ceases.

(5) Provide a permanent, conspicuous label that lists the operating requirements in subdivisions (3), (4), (6), and (7).

(6) Store waste solvent only in covered containers.

(7) Prohibit the dispose or transfer of waste solvent in such a manner that could allow greater than twenty percent (20%) of the waste solvent (by weight) to evaporate into the atmosphere.

(b) Pursuant to 326 IAC 8-3-2(b) (Cold Cleaner Degreaser Control Equipment and Operating Requirements), for cold cleaner degreaser operations without remote solvent reservoirs, the Permittee shall ensure that the following additional control equipment and operating requirements are met:

(1) Equip the degreaser with one (1) of the following control devices if the solvent is heated to a temperature of greater than forty-eight and nine-tenths (48.9) degrees Celsius (one hundred twenty (120) degrees Fahrenheit):

(A) A freeboard that attains a freeboard ratio of seventy-five hundredths (0.75) or greater.

(B) A water cover when solvent used is insoluble in, and heavier than, water.

(C) A refrigerated chiller.

(D) Carbon adsorption.

(E) An alternative system of demonstrated equivalent or better control as those outlined in clauses (A) through (D) that is approved by the department. An alternative system shall be submitted to the U.S. EPA as a SIP revision.

(2) Ensure the degreaser cover is designed so that it can be easily operated with one (1) hand if the solvent is agitated or heated.

(3) If used, solvent spray:

(A) must be a solid, fluid stream; and

(B) shall be applied at a pressure that does not cause excessive splashing.

D.38.2 Material Requirements for Cold Cleaner Degreasers [326 IAC 8-3-8]

Pursuant to 326 IAC 8-3-8(b)(2), no person shall operate a cold cleaner degreaser with a solvent that has a VOC composite partial vapor pressure that exceeds one (1) millimeter of mercury (nineteen-thousandths (0.019) pound per square inch) measured at twenty (20) degrees Celsius (sixty-eight (68) degrees Fahrenheit).

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

D.38.3 Record Keeping Requirements

(a) In order to document the compliance status with Condition D.38.2, the Permittee shall maintain each of the following records for each purchase:

(1) The name and address of the solvent supplier.

(2) The date of purchase (or invoice/bill date of contract servicer indicating service date).

(3) The type of solvent purchased.

(4) The total volume of the solvent purchased.

(5) The true vapor pressure of the solvent measured in millimeters of mercury at twenty (20) degrees Celsius (sixty eight (68) degrees Fahrenheit).

(b) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the record keeping required by this condition.

SECTION D.39 EMISSIONS UNIT OPERATION CONDITIONS – Fuel Dispensing Facility

Emissions Unit Description:

(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 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:

(1) A pressure decay or leak test.

(2) A dynamic pressure drop test.

(3) 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:

(a) That a certified vapor collection and control system has been installed and tested to verify its performance according to its specifications.

(b) That proper maintenance has been conducted in accordance with the manufacturer’s specifications and requirements.

(c) The time period and duration of all malfunctions of the vapor collection and control system.

(d) The motor vehicle fuel throughput of the facility for each calendar month of the previous year.

(e) That operators and employees are trained and instructed in the proper operation and maintenance of the vapor collection and control system.

Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by this condition.

SECTION D.40 EMISSIONS UNIT OPERATION CONDITIONS – CALUMET WAREHOUSE

Emissions Unit Description:

(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) Boiler No. 1 with a maximum design capacity of 2.0 mmBTU/hr heat input and is natural gas-fired only, constructed in 2006, venting to stack, S-1.

(2) Boiler No. 2 with a maximum design capacity of 2.0 mmBTU/hr heat input and is natural gas-fired only, constructed in 2006, venting to stack, S-2.

(3) Boiler No. 3 with a maximum design capacity of 2.0 MMBtu/hr heat input and is natural gas-fired only, constructed in 2006, venting to stack, S-3.

(4) Boiler No. 4 with a maximum design capacity of 2.0 mmBtu/hr heat input and is natural gas-fired only, constructed in 2006, venting to stack, S-4.

(5) Boiler No. 5 with a maximum design capacity of 2.0 mmBtu/hr heat input and is natural gas-fired only, constructed in 2006, venting to stack, S-5.

(6) Boiler No. 6 with a maximum design capacity of 2.0 mmBtu/hr heat input and is natural gas-fired only, constructed in 2006, venting to stack, S-6.

(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)(3), the particulate matter content of natural gas burned in the Boilers No. 1 - 6 shall be limited to 0.01 grains per dry standard cubic foot natural gas, each.

SECTION D.41 EMISSIONS UNIT OPERATION CONDITIONS - Tank Cleaning Facility

Emissions Unit Description:

(mm) 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 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:

(1) 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 the wet scrubber/carbon canister system S-1.

(2) Two (2) enclosed centrifuges (identified as Centrifuge #1 and #2) with no process vents.

(3) 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.

(4) Six (6) portable rectangular storage tanks, including:

(A) 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 the wet scrubber/carbon canister system S-1.

(B) 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 the wet scrubber/carbon canister system S-1.

(C) 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 the wet scrubber/carbon canister system S-1.

(5) 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; 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]

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.

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 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the Tank Cleaning Facility shall be an affected facility for purposes of 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the Tank Cleaning Facility no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.41.5 Prevention of Significant Deterioration [326 IAC 2-2], Emission Offset [326 IAC 2-3] and Nonattainment NSR [326 IAC 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.41.4. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

D.41.6 Consent Decree (Civil No. 2:12-CV-00207) Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, "fuel oil" shall not be burned in any heater or boiler associated with the Tank Cleaning Facility.

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

D.41.7 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.41.8 Record Keeping Requirements

(a) To document the compliance status with Condition D.41.1, the Permittee shall maintain records of the number of operating hours for the Tank Cleaning Facility.

(b) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.41.4(a), the Permittee shall comply with equipment leak record keeping requirements specified in the LDAR plan.

(c) To document compliance with Condition D.41.4(b), the Permittee shall keep records pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(d) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a) and (b) of this condition.

D.41.9 Reporting Requirements

(a) A quarterly summary of the information to document the compliance status with Condition D.41.1 shall be submitted not later than thirty (30) days after the end of the quarter being reported.

(b) Pursuant to 326 IAC 8-4-8 and to document the compliance status with Condition D.41.4(a), the Permittee shall submit reports as specified in the LDAR plan.

(c) To document compliance with Condition D.41.4(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(d) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a) and (b) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.42 EMISSIONS UNIT OPERATION CONDITIONS – Gas Oil Hydrotreating Unit

Emissions Unit Description:

(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 WRMP 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- NO_X burners
F-901B	47	802-02	Ultra low- NO_X burners

(2) Associated valves, pumps, compressors (K-901A, K-901B, K-901C, and K-902), pressure relief devices, sampling connection systems, open-ended lines or valves, flanges or other connectors, and instrumentation and heat exchange systems.

(3) The GOHT Unit is connected to the GOHT Flare and associated flare gas recovery system FGRS2 (included in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns.

(4) Miscellaneous process vent emissions, which are routed to the GOHT Flare and associated flare gas recovery system FGRS2 (identified in Section D.35).

(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, particulate matter emissions from each of the heaters F-901A and F-901B 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 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, 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) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 , the emissions of NO_X shall not exceed 0.04 pounds per million BTU, per heater.

(b) The emissions of VOC shall not exceed 0.0054 pounds per million BTU.

(c) Following the completion of the WRMP project, the emissions of SO_2 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_{10} shall not exceed 0.0075 pounds per million BTU of fuel burned.

(e) Pursuant to SSM 089-32033-00453, the emissions of PM shall not exceed 0.0075 pounds per million BTU.

(f) The emissions of CO shall not exceed 0.02 pounds per million BTU.

(g) 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

(h) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.42.3. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

D.42.3 Equipment Leaks of Volatile Organic Compounds (VOC) [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 SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, the GOHT is an affected facility pursuant to 40 CFR 60, Subpart GGGa, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, and the following shall apply:

(1) The Permittee shall comply with the requirements specified in Section F.9 – 40 CFR 60, Subpart GGGa and Condition F.9.3 – 40 CFR 60, Subpart VVa for equipment leaks of VOC from each, valve, pump, pressure relief device, sampling connection system, open ended valve or line, and flange or other connector in VOC service at the GOHT no later than one year from the “Date of Entry” of the Consent Decree in Civil No. 2:12-CV-00207.

(2) Entry of the Consent Decree in Civil No. 2:12-CV-00207 satisfies the following notification and testing requirements that are triggered by initial applicability of 40 CFR 60, Subparts A and GGGa: 40 CFR 60.7, 60.8, 60.18 (but only with respect to the following flares: FCU, Alky, 4UF, DDU, SRU and VRU), 60.482-1a(a), 60.482-2a(e), 60.482-7a(f), 60.485a(g), and 60.487a(e).

D.42.4 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the date of initial start-up, GOHT Heaters F-901A and F-901B shall be affected facilities for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60 Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for GOHT Heaters F-901A and F-901B.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, GOHT Heaters F-901A and F-901B shall be affected facilities for NO_X as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja for NO_X emissions for process heaters by the date specified in 40 CFR 60, Subpart Ja. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for GOHT Heaters F-901A and F-901B.

D.42.5 Consent Decree (Civil No. 2:12-CV-00207) Requirements

(a) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, fuel oil shall not be burned in the GOHT Heaters F-901A and F-901B. “Fuel Oil” shall mean any liquid fossil fuel with sulfur content of greater than 0.05% by weight.

(b) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, by no later than July 1, 2014, the total sulfur concentration of refinery fuel gas combusted in GOHT Heaters F-901A and F-901B shall not exceed 70 ppmvd total sulfur calculated as H_2S on a "12-month rolling average" basis.

Compliance Determination Requirements

D.42.6 Operating Requirement

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to demonstrate compliance with Condition D.42.2(a), the GOHT Heaters F-901A and F-901B shall operate using only ultra low- NO_X burners.

D.42.7 Compliance Determination Requirements

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, compliance with the NO_X emissions limits in Condition D.42.2(a) for Heaters F-901A and F-901B shall be calculated using 40 CFR Part 60, Appendix A, Method 19 and the NO_X concentration measured in the most recent stack test demonstrating compliance per Condition D.42.8.

D.42.8 Performance Testing Requirements

(a) Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the GOHT Heater F-901A, the Permittee shall perform NO_X, PM, PM10, CO, and VOC testing of GOHT Heater F-901A utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance

Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the GOHT Heater F-901B, the Permittee shall perform NO_X, PM, PM_{10}, CO, and VOC testing of GOHT Heater F-901B utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

D.42.9 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in GOHT Heaters F-901A and F-901B. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, EPA Methods 15A or 16C shall be used as the reference method. In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) The Total Sulfur Continuous Analyzer shall be calibrated, maintained, and operated for determining compliance with SO_2 emissions limits for F-901A and F-901B in Conditions D.42.2(c) and D.42.5(b) in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment. The SO_2 emissions shall be calculated based on the conversion of one mole of sulfur in the fuel gas to one mole of SO_2.

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

D.42.10 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.42.11 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 document the compliance status with Condition D.42.2, the Permittee shall maintain the records of monthly firing rates and SO_2 emissions at F-901A and F-901B.

(c) Pursuant to 326 IAC 3-5-6 and to document the compliance status with Condition D.42.9, 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) Pursuant to 40 CFR 60, Subpart Ja and to document the compliance status with Condition D.42.4, the Permittee shall maintain the records specified in Section F.3.

(e) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Conditions D.42.3 (b), the Permittee shall maintain the records specified in Section F.9.

(f) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b) and (c) of this condition.

D.42.12 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 document the compliance status with Condition D.42.2, the Permittee shall submit a quarterly summary of the monthly firing rates and SO_2 emissions for heaters F-901A and F-901B not later than thirty (30) days after the end of the quarter being reported. Section C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. The quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

(c) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.42.2 and D.42.9, the Permittee shall submit reports of excess SO_2 emissions not later than 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 C - General Reporting contains the Permittee's obligation with regard to the reporting required by this condition. The quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

(d) Pursuant to 40 CFR 60, Subpart Ja and to document the compliance status with Condition D.42.4, the Permittee shall submit reports as specified in Section F.3.

(e) Pursuant to 40 CFR 60, Subpart GGGa and to document the compliance status with Conditions D.42.3(b), the Permittee shall submit reports as specified in Section F.9.

(f) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (b) and (c) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.43 EMISSIONS UNIT OPERATION CONDITIONS – New Hydrogen Unit

Emissions Unit Description:

(oo) The New Hydrogen Unit (New HU), identified as Unit ID 801, owned and operated by Praxair, Inc. and constructed as part of the WRMP 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 NO_X. The New HU heater stacks have continuous emissions monitors (CEMS) for NO_X 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

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

(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 HU is connected to the New 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 New HU Flare will be operated with a water seal or nitrogen purge. As such, there will be no purge gas emissions from the New HU Flare. The New HU Flare exhausts to S/V 801 03.

(4) Associated valves, pumps, compressors (C-9210 and C-9230), pressure relief devices, sampling connection systems, open ended lines or valves, flanges or other connectors, and instrumentation and heat exchange systems.

(5) One diesel-fueled emergency generator rated at 1,214 HP.

(6) HU steam vent.

(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, particulate matter emissions from each of the heaters HU-1 and HU-2, the HU Cooling Tower, the HU Flare, and the emergency generator 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 2-1.1-4] and Emission Offset [326 IAC 2-3]

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

For each of the two (2) heaters HU-1 and HU-2:

(a) 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 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 New HU Flare pilot gas:

(b) The emissions of NO_X shall not exceed 100 pounds per million cubic feet of fuel burned.

(c) The emissions of VOC shall not exceed 5.5 pounds per million cubic feet of fuel burned.

(d) The emissions of SO_2 shall not exceed 0.6 pounds per million cubic feet of fuel burned.

(e) The emissions of PM and PM_{10} shall not exceed 1.9 and 7.6 pounds per million cubic feet of fuel burned, respectively.

(f) The pilot gas used at the New HU Flare shall be limited to 2,233,800 cubic feet per 12 consecutive month period.

For the HU cooling tower:

(g) The average concentration of total dissolved solids (TDS) in the cooling water return including make up water, to the HU Cooling Tower shall not exceed an average annual concentration of 6300 mg/L per 12 consecutive month period.

(h) The emissions of PM and PM_{10} from HU Cooling Tower shall each not exceed 0.42 pounds per hour.

Pursuant to SSM 089-32033-00453, for the New HU heaters (HU-1 and HU-2), New HU Flare pilot gas, New HU Flare planned startup and shutdown events, HU steam vent, and emergency generator:

(i) The total emissions of NO_X shall not exceed 104.9 tons per 12 consecutive month period, with compliance determined at the end of each month.

(j) The total emissions of VOC shall not exceed 27.4 tons per 12 consecutive month period, with compliance determined at the end of each month.

(k) The total emissions of SO_2 shall not exceed 1.2 tons per 12 consecutive month period, with compliance determined at the end of each month.

(l) The total emissions of PM and PM_{10} shall each not exceed 54.9 tons per 12 consecutive month period, with compliance determined at the end of each month.

(m) The total emissions of CO shall not exceed 121.0 tons per 12 consecutive month period, with compliance determined at the end of each month.

Compliance with the firing rate limits and the NO_X, VOC, CO, SO_2, 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 NO_X, VOC, CO, SO_2, PM and PM_{10} for the WRMP project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants. Should any of the limits contained in Conditions D.43.1 and D.43.2 be exceeded, the actual emissions from the affected period must be evaluated to show that the actual net emissions increase from the WRMP project remains below the significant levels.

D.43.3 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.43.4 Standards of Performance for Petroleum Refineries [326 IAC 12][40 CFR 60, Subpart Ja]

Pursuant to SSM 089-32033-00453 and as required by the Consent Decree entered in Civil No. 2:12-CV-00207, upon the "Date of Entry" of the Consent Decree in Civil No. 2:12-CV-00207, the New HU heaters HU-1 and HU-2 shall be affected facilities for SO_2 as the term is used in 40 CFR 60, Subparts A and Ja, and shall be subject to and comply with the applicable requirements of 40 CFR 60, Subparts A and Ja and specified in Section F.3 for SO_2 emissions for fuel gas combustion devices. Entry of Civil No. 2:12-CV-00207 and compliance with the relevant monitoring requirements of Subpart Ja shall satisfy the notice requirements of 40 CFR § 60.7(a) and the initial performance test requirement of 40 CFR § 60.8(a) for New HU heaters HU-1 and HU-2.

Compliance Determination Requirements

D.43.5 Operating Requirement

(a) Pursuant to Permit SSM 089-25484-00453, issued May 1, 2008 and in order to demonstrate compliance with Condition D.43.2, the Permittee shall operate the heaters HU-1 and HU-2 using only low NO_X burners.

(b) Pursuant to Permit SSM 089-25484-00453, issued May 1, 2008 and in order to comply with Condition D.43.2, the SCRs shall be operated as necessary to meet the NO_X emissions limits for heaters HU-1 and HU-2.

(c) Pursuant to Permit SSM 089-25484-00453, issued May 1, 2008 and 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.43.6 Testing Requirements

Not later than 180 days after the startup of the New Heater HU-1 or HU-2, whichever occurs first, the Permittee shall perform PM, PM10, and VOC testing of one (1) of the New Heaters (HU-1 or HU-2) utilizing methods approved by the commissioner. A total of one (1) of the two (2) New Heaters (HU-1 or HU-2) shall be tested at least once every 3 years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition. PM10 includes filterable and condensable PM.

D.43.7 Continuous Monitoring – HU Flare [326 IAC 2-2]

The H2S or Total Sulfur (if approved in an alternative monitoring plan) continuous emission monitoring systems (CEMS) for the New HU Flare shall be calibrated, maintained, and operated in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment.

D.43.8 Continuous Emissions Monitoring

The CO and NO_X continuous emission monitoring systems (CEMS) for heaters HU-1 and HU-2 shall be calibrated, maintained, and operated for measuring CO and NO_X in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment.

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

D.43.9 Compliance Monitoring Requirements [326 IAC 2-3]

(a) To monitor compliance with Condition D.43.2, the Permittee shall take weekly measurements of the total dissolved solids (TDS) in the water return, including make up water, 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.

(b) Pursuant to SSM 089-32033-00453, a continuous parameter measurement monitoring system shall be calibrated, maintained, and operated on each process vent connected to, and exhausting to the New HU Flare during startup and other process venting from heaters HU-1 and HU-2, respectively, for compiling emissions using software with inputs of duration of vent value openings plus process throughput.

(c) Pursuant to SSM 089-32033-00453, the instruments used for determining parameter measurements mentioned in (b) above shall comply with Section C - Instrument Specifications, of this permit, shall be subject to approval by IDEM, OAQ, and shall be calibrated or replaced at least once every six (6) months or other time period specified by the manufacturer. The Permittee shall maintain records of the manufacturer specifications, if used.

(d) Pursuant to SSM 089-32033-00453, in lieu of compliance with Condition C.12(c), whenever a H_2S or Total Sulfur continuous emission monitoring system is malfunctioning on the New HU or will be down for calibration, maintenance, or repairs for more than twenty-four (24) hours, the Permittee shall measure and record Draeger tube sampling of the fuel gas one time per day until the primary CEMS or a backup CEMS is brought online.

(e) Pursuant to SSM 089-32033-00453, whenever the NO_X continuous emission monitoring system on the heaters HU-1 or HU-2 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 exit flue gas temperature of the heater to demonstrate that the operation of the unit continues in a normal manner. These parametric monitoring readings shall be recorded at least once per day until the primary CEM or backup CEM is brought online.

(f) Pursuant to SSM 089-32033-00453, whenever the CO continuous emission monitoring system on the heaters HU-1 or HU-2 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, exit flue gas temperature of the heater and percent oxygen at the exit flue gas of the heater to demonstrate that the operation of the unit continues in a normal manner. These parametric monitoring readings shall be recorded at least once per day until the primary CEM or a backup CEM is brought online.

(g) Pursuant to SSM 089-32033-00453, in lieu of compliance with Condition C.12(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 60, Ja for affected process heaters HU-1 and HU-2.

(h) Pursuant to SSM 089-32033-00453, in lieu of compliance with Condition C.13(a), in the event that a breakdown of the emission monitoring equipment occurs on the New HU, 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 (e.g. parametric monitoring) or intermittent monitoring of the parameter should be implemented at intervals no less frequent than required in Section D.43 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, unless otherwise stipulated in Section C.12 or Section D.43.

D.43.10 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.43.11 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 document the compliance status with Condition D.43.2, the Permittee shall maintain the records of monthly firing rates using natural gas and PSA tailgas and CO, NO_X and SO_2 emissions at heaters HU-1 and HU-2.

(c) In order to document the compliance status with Condition D.43.2, the Permittee shall maintain the records of monthly firing rates using pilot gas at the New HU Flare.

(d) To document the compliance status with Condition D.43.2, the Permittee shall maintain records of the total dissolved solids (TDS) in the water return, including make up water, 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 the compliance status with Conditions D.43.7 and D.43.8, 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.

(f) Pursuant to 40 CFR 60, Subpart Ja and to document the compliance status with Condition D.43.4, the Permittee shall maintain the records specified in Section F.3.

(g) In order to document the compliance status with Condition D.43.2, maintain software compilation of emissions using process throughput and vent valve opening duration for each process vent connected to, and exhausting to the New HU Flare during startup of heaters HU-1 and HU-2, respectively.

(h) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (c), (d), (e) and (g) of this condition.

D.43.12 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 document the compliance status with Condition D.43.2, the Permittee shall submit a quarterly summary of the fuel usages at heaters HU-1 and HU-2 and New HU Flare and CO, NO_X, and SO_2 emissions for heaters HU-1 and HU-2 not later than thirty (30) days after the end of the quarter being reported.

(c) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.43.2, D.43.7, and D.43.8, the Permittee shall submit reports of excess SO_2, CO, and NO_X emissions not later than 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

(d) Pursuant to 40 CFR 60, Subpart Ja and to document the compliance status with Condition D.43.4, the Permittee shall submit reports as specified in Section F.3.

(e) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (b) and (c) of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

SECTION D.44 RESERVED

SECTION D.45 EMISSIONS UNIT OPERATION CONDITIONS – Firepump Engines and Concrete Crusher

Emissions Unit Description:

Insignificant Activity:

(ee) Three (3) emergency firepump engines, identified as Firepump 1, 2 and 3, per SPM 089-25488-00453, one rated at 359 HP and two rated at 460 HP.

(ff) 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 2-1.1-4] Minor Limits

In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, 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 NO_X, VOC, CO, SO_2, PM and PM_{10} for the WRMP project remain below the significant levels, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

SECTION E.1 Clean Air Interstate (CAIR) Nitrogen Oxides Annual, Sulfur Dioxide, and Nitrogen Oxides Ozone Season Trading Programs – CAIR Permit for CAIR Units Under 326 IAC 24-1-1(a), 326 IAC 24-2-1(a), and 326 IAC 24-3-1(a)

NO_x Budget Source:

(x) A portion of No. 3 Stanolind Power Station (SPS) identified as Unit ID 503. The following specific units are considered to be affected facilities: [Section D.24]

(1) #31 Boiler
(2) #32 Boiler
(3) #33 Boiler
(4) #34 Boiler
(5) #36 Boiler

Under 326 IAC 10-4-1(a), the above boilers are NOx budget units.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

E.1.1 Automatic Incorporation of Definitions [326 IAC 24-1-7(e)][326 IAC 24-2-7(e)][326 IAC 24-3-7(e)][40 CFR 97.123(b)][40 CFR 97.223(b)][40 CFR 97.323(b)]

This CAIR permit is deemed to incorporate automatically the definitions of terms under 326 IAC 24-1-2, 326 IAC 24-2-2, and 326 IAC 24-3-2.

E.1.2 Standard Permit Requirements [326 IAC 24-1-4(a)][326 IAC 24-2-4(a)][326 IAC 24-3-4(a)][40 CFR 97.106(a)][40 CFR 97.206(a)][40 CFR 97.306(a)]

(a) The owners and operators of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and CAIR NO_X units, CAIR SO_2 unit(s), and CAIR NO_X ozone season units shall operate each unit in compliance with this CAIR permit.

(b) The CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units subject to this CAIR permit are:

(1) At No. 3 Stanolind Power Station (SPS) and Boiler Water Treating Plant, #31 Boiler, #32 Boiler, #33 Boiler, #34 Boiler, and #36 Boiler.

E.1.3 Monitoring, Reporting, and Record Keeping Requirements [326 IAC 24-1-4(b)][326 IAC 24-2-4(b)][326 IAC 24-3-4(b)][40 CFR 97.106(b)][40 CFR 97.206(b)][40 CFR 97.306(b)]

(a) The owners and operators, and the CAIR designated representative, of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall comply with the monitoring, reporting, and record keeping requirements of 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) The emissions measurements recorded and reported in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 shall be used to determine compliance by each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source with the CAIR NO_X emissions limitation under 326 IAC 24-1-4(c), CAIR SO_2 emissions limitation under 326 IAC 24-2-4(c), and CAIR NO_X ozone season emissions limitation under 326 IAC 24-3-4(c) and Condition E.1.4 - Nitrogen Oxides Emission Requirements, Condition E.1.5 - Sulfur Dioxide Emission Requirements, and Condition E.1.6 - Nitrogen Oxides Ozone Season Emission Requirements.

E.1.4 Nitrogen Oxides Emission Requirements [326 IAC 24-1-4(c)][40 CFR 97.106(c)]

(a) As of the allowance transfer deadline, the owners and operators of each CAIR NO_X source and each CAIR NO_X unit at the source shall hold, in the source's compliance account, CAIR NO_X allowances available for compliance deductions for the control period under 326 IAC 24-1-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X units at the source, as determined in accordance with 326 IAC 24-1-11.

(b) A CAIR NO_X unit shall be subject to the requirements under (a) above for the control period starting on the later of January 1, 2009, or the deadline for meeting the unit's monitor certification requirements under section 326 IAC 24-1-11(c)(1), 11(c)(2), or 11(c)(5) and for each control period thereafter.

(c) A CAIR NO_X allowance shall not be deducted for compliance with the requirements under (a) above and 326 IAC 24-1-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_X allowance was allocated.

(d) CAIR NO_X allowances shall be held in, deducted from, or transferred into or among CAIR NO_X allowance tracking system accounts in accordance with 326 IAC 24-1-9, 326 IAC 24-1-10, and 326 IAC 24-1-12.

(e) A CAIR NO_X allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_X annual trading program. No provision of the CAIR NO_X annual trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-1-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR NO_X allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-1-8, 326 IAC 24-1-9, 326 IAC 24-1-10, or 326 IAC 24-1-12, every allocation, transfer, or deduction of a CAIR NO_X allowance to or from a CAIR NO_X source's compliance account is incorporated automatically in this CAIR permit.

E.1.5 Sulfur Dioxide Emission Requirements [326 IAC 24-2-4(c)][40 CFR 97.206(c)]

(a) As of the allowance transfer deadline, the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, a tonnage equivalent of CAIR SO_2 allowances available for compliance deductions for the control period under 326 IAC 24-2-8(j) and 326 IAC 24-2-8(k) not less than the tons of total sulfur dioxide emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance with 326 IAC 24-2-10.

(b) A CAIR SO_2 unit shall be subject to the requirements under (a) above for the control period starting on the later of January 1, 2010 or the deadline for meeting the unit's monitor certification requirements under section 326 IAC 24-2-10(c)(1), 10(c)(2), or 10(c)(5) and for each control period thereafter.

(c) A CAIR SO_2 allowance shall not be deducted for compliance with the requirements under (a) above and 326 IAC 24-2-4(c)(1), for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.

(d) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 allowance tracking system accounts in accordance with 326 IAC 24-2-8, 326 IAC 24-2-9, and 326 IAC 24-2-11.

(e) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 trading program. No provision of the CAIR SO_2 trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-2-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR SO_2 allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-2-8, 326 IAC 24-2-9, or 326 IAC 24-2-11, every allocation, transfer or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 source's compliance account is incorporated automatically in this CAIR permit.

E.1.6 Nitrogen Oxides Ozone Season Emission Requirements [326 IAC 24-3-4(c)][40 CFR 97.306(c)]

(a) As of the allowance transfer deadline, the owners and operators of the each CAIR NO_X ozone season source and each CAIR NO_X ozone season unit at the source shall hold, in the source's compliance account, CAIR NO_X ozone season allowances available for compliance deductions for the control period under 326 IAC 24-3-9(i) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_X ozone season units at the source, as determined in accordance with 326 IAC 24-3-11.

(b) A CAIR NO_X unit shall be subject to the requirements under (a) above for the control period starting on the later of May 1, 2009 or the deadline for meeting the unit's monitor certification requirements under section 326 IAC 24-3-11(c)(1), 11(c)(2), 11(c)(3), or 11(c)(7) and for each control period thereafter.

(c) A CAIR NO_X ozone season allowance shall not be deducted for compliance with the requirements under (a) above and 326 IAC 24-3-4(c)(1), for a control period in a calendar year before the year for which the CAIR NO_X ozone season allowance was allocated.

(d) CAIR NO_X ozone season allowances shall be held in, deducted from, or transferred into or among CAIR NO_X ozone season allowance tracking system accounts in accordance with 326 IAC 24-3-9, 326 IAC 24-3-10, and 326 IAC 24-3-12.

(e) A CAIR NO_X allowance is a limited authorization to emit one (1) ton of nitrogen oxides in accordance with the CAIR NO_X ozone season trading program. No provision of the CAIR NO_X ozone season trading program, the CAIR permit application, the CAIR permit, or an exemption under 326 IAC 24-3-3 and no provision of law shall be construed to limit the authority of the State of Indiana or the United States to terminate or limit the authorization.

(f) A CAIR NO_X allowance does not constitute a property right.

(g) Upon recordation by the U.S. EPA under 326 IAC 24-3-8, 326 IAC 24-3-9, 326 IAC 24-3-10, or 326 IAC 24-3-12, every allocation, transfer, or deduction of a CAIR NO_X ozone season allowance to or from a CAIR NO_X ozone season source's compliance account is incorporated automatically in this CAIR permit.

E.1.7 Excess Emissions Requirements [326 IAC 24-1-4(d)][326 IAC 24-2-4(d)][326 IAC 24-3-4(d)][40 CFR 97.106(d)][40 CFR 97.206(d)][40 CFR 97.306(d)]

The owners and operators of a CAIR NO_X source and each CAIR NO_X unit that emits nitrogen oxides during any control period in excess of the CAIR NO_X emissions limitation shall do the following:

(a) Surrender the CAIR NO_X allowances required for deduction under 326 IAC 24-1-9(j)(4).

(b) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-1-4, the Clean Air Act (CAA), and applicable state law.

The owners and operators of a CAIR SO_2 source and each CAIR SO_2 unit that emits sulfur dioxide during any control period in excess of the CAIR SO_2 emissions limitation shall do the following:

(a) Surrender the CAIR SO_2 allowances required for deduction under 326 IAC 24-2-8(k)(4).

(b) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-2-4, the Clean Air Act (CAA), and applicable state law.

The owners and operators of a CAIR NO_X ozone season source and each CAIR NO_X ozone season unit that emits nitrogen oxides during any control period in excess of the CAIR NO_X ozone season emissions limitation shall do the following:

(a) Surrender the CAIR NO_X ozone season allowances required for deduction under 326 IAC 24-3-9(j)(4).

(b) Pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, the Clean Air Act (CAA) or applicable state law.

Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 326 IAC 24-3-4, the Clean Air Act (CAA), and applicable state law.

E.1.8 Record Keeping Requirements [326 IAC 24-1-4(e)][326 IAC 24-2-4(e)][326 IAC 24-3-4(e)][326 IAC 2-7-5(3)][40 CFR 97.106(e)][40 CFR 97.206(e)][40 CFR 97.306(e)]

Unless otherwise provided, the owners and operators of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall keep 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 from the date the document was created:

(a) The certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), 326 IAC 24-3-6(h) for the CAIR designated representative for the source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation. The certificate and documents shall be retained on site at the source or at a central location within Indiana for those owners or operators with unattended sources beyond such five (5) year period until such documents are superseded because of the submission of a new account certificate of representation under 326 IAC 24-1-6(h), 326 IAC 24-2-6(h), 326 IAC 24-3-6(h) changing the CAIR designated representative.

(b) All emissions monitoring information, in accordance with 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11, provided that to the extent that 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11 provides 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 CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program.

(d) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program or to demonstrate compliance with the requirements of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program.

This period may be extended for cause, at any time before the end of five (5) years, in writing by IDEM, OAQ or the U.S. EPA. Unless otherwise provided, all records shall be maintained in accordance with Section C - General Record Keeping Requirements, of this permit.

E.1.9 Reporting Requirements [326 IAC 24-1-4(e)][326 IAC 24-2-4(e)][326 IAC 24-3-4(e)][40 CFR 97.106(e)][40 CFR 97.206(e)][40 CFR 97.306(e)]

(a) The CAIR designated representative of the CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source shall submit the reports required under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program, including those under 326 IAC 24-1-11, 326 IAC 24-2-10, and 326 IAC 24-3-11.

(b) Pursuant to 326 IAC 24-1-4(e), 326 IAC 24-2-4(e), and 326 IAC 24-3-4(e) and 326 IAC 24-1-6(e)(1), 326 IAC 24-2-6(e)(1), and 326 IAC 24-3-6(e)(1), each submission under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program shall include the following certification statement by the CAIR designated representative: “I am authorized to make this submission on behalf of the owners and operators of the source or 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 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to IDEM, OAQ, the CAIR designated 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 46204-2251

(d) Where 326 IAC 24-1, 326 IAC 24-2, and 326 IAC 24-3 requires a submission to U.S. EPA, the CAIR designated 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.1.10 Liability [326 IAC 24-1-4(f)][326 IAC 24-2-4(f)][326 IAC 24-3-4(f)][40 CFR 97.106(f)][40 CFR 97.206(f)][40 CFR 97.306(f)]

The owners and operators of each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall be liable as follows:

(a) Each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source and each CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall meet the requirements of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program.

(b) Any provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program that applies to a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source or the CAIR designated representative of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source shall also apply to the owners and operators of such source and of the CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units at the source.

(c) Any provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program that applies to a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit or the CAIR designated representative of a CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit shall also apply to the owners and operators of such units.

E.1.11 Effect on Other Authorities [326 IAC 24-1-4(g)][326 IAC 24-2-4(g)][326 IAC 24-3-4(g)][40 CFR 97.106(g)][40 CFR 97.206(g)][40 CFR 97.306(g)]

No provision of the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program, a CAIR permit application, a CAIR permit, or an exemption under 326 IAC 24-1-3, 326 IAC 24-2-3, and 326 IAC 24-3-3 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source or CAIR NO_X unit(s), CAIR SO_2 unit(s), and CAIR NO_X ozone season unit(s) from compliance with any other provision of the applicable, approved state implementation plan, a federally enforceable permit, or the Clean Air Act (CAA).

E.1.12 CAIR Designated Representative and Alternate CAIR Designated Representative [326 IAC 24-1-6][326 IAC 24-2-6][326 IAC 24-3-6][40 CFR 97, Subpart BB][40 CFR 97, Subpart BBB][40 CFR 97, Subpart BBBB]

Pursuant to 326 IAC 24-1-6, 326 IAC 24-2-6, and 326 IAC 24-3-6:

(a) Except as specified in 326 IAC 24-1-6(f)(3), 326 IAC 24-2-6(f)(3), and 326 IAC 24-3-6(f)(3), each CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source, including all CAIR NO_X units, CAIR SO_2 units, and CAIR NO_X ozone season units at the source, shall have one (1) and only one (1) CAIR designated representative, with regard to all matters under the CAIR NO_X annual trading program, CAIR SO_2 trading program, and CAIR NO_X ozone season trading program concerning the source or any CAIR NO_X unit, CAIR SO_2 unit, and CAIR NO_X ozone season unit at the source.

(b) The provisions of 326 IAC 24-1-6(f), 326 IAC 24-2-6(f), and 326 IAC 24-3-6(f) shall apply where the owners or operators of a CAIR NO_X source, CAIR SO_2 source, and CAIR NO_X ozone season source choose to designate an alternate CAIR designated representative.

SECTION E.2 Consolidated Federal Air Rule General Provisions (40 CFR 65, Subpart A)

Emissions Unit Description:

(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. The following specific units are considered to be affected facilities: [Section D.1]

- T-2 Primary Tower
- T-3C Primary Gas Oil Stripper
- T-3B Light Middle Distillate Stripper
- T-3A Heavy Naphtha Stripper
- E-3A/B/C/D T-2 Crude Tower Overhead Condenser
- D-1 Primary Tower Reflux Drum
- E-1A/E-1B Secondary Overhead Condensers
- D-9 Crude Tower Second Stage Condenser (LVN) Drum
- D-22 Fuel Gas K.O. Drum
- T-4 First Vacuum Tower
- E-18AX/BX/CX Condensers
- D-21 Hotwell
- T-5 Second Vacuum Tower
- E-35, 35A, E-36AX/BX/C Condensers
- D-26A Hotwell
- L-51 Wet Gas K.O. Drum
- D-23 Separator
- D-201 Flash Drum
- T-200 Crude Tower
- D-202 Crude Tower Reflux Drum
- D-203 Crude Tower Second Stage Condenser Drum
- T-201D PGO Stripper
- T-201C HMD Stripper
- T-201B LMD Stripper
- T-201A HVN Stripper
- T-300 Vacuum Tower
- D-300A Hotwell
- E-305 Pre Condenser
- E-305A/B/C Condensers
- K-300A/B Vent Gas Compressors
- D-301 Separator
- D-204A Fuel Gas Knock Out Drum
- Nos. 11A and 11C Pipe Stills Refinery Fuel Gas System
- H-1X Process Heater
- H-2 Process Heater
- H-3 Process Heater
- H-200 Process Heater
- H-300 Process Heater

(b) Cokers. The following specific units are considered to be affected facilities: [Section D.2]

- T-201 Coker2 Fractionator
- D-220 Fractionator Water Wash Coalescer
- D-202 Kerosene Stripper
- E-212 A/B/C/D/E/F Fractionator Overhead Condensers
- E-212 G/H/I/J/K/L Fractionator Overhead Condensers
- D-214 Fractionator Overhead Drum
- D-211 Coker2 Blowdown Drum

- D-212 Blowdown Settling Drum
- D-213 Water Seal Drum - operating scenario #1 Process Heaters /Boilers
- D-213 Water Seal Drum - operating scenario #2 Flare
- D-241 Oily Water Separator – operating scenario #1 Process Heaters/Boilers
- D-241 Oily Water Separator – operating scenario #2 Flare
- #2 Coker Refinery Fuel Gas System
- F-201 Process Heater
- F-202 Process Heater
- F-203 Process Heater
- South Flare and Flare System
- Flare Gas Recovery System 1 (FGRS1)

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the WRMP 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 WRMP project. Also, as part of the WRMP Project, there will be upgrades made to the atmospheric and vacuum distillation towers and various heat exchangers and associated piping. The following specific units are considered to be affected facilities: [Section D.3]

- T-101 Primary Fractionator
- T-4 Primary Gasoil Stripper
- T-103B Middle Distillate Stripper
- T-103C Middle Distillate Stripper
- E120 A/B/C/D Primary Fractionator Overhead Condensers
- D-112 Primary Reflux Drum
- E137 Light Virgin Naphtha Condenser
- D-111 Wet Gas Knockout Drum
- D-116 Fuel Gas Knockout Drum
- D-3C Relief Collection Drum - operating scenario #1 Process Heaters/Boilers
- D-3C Relief Collection Drum - operating scenario #2 Flare
- P-125A/B/C 1st Stage Vacuum Tower Overhead Ejectors - release to RV manifold & flare
- P-125A/B/C 1st Stage Vacuum Tower Overhead Ejectors - release to T-102 prior to being routed to fuel gas
- P-125A/B/C 1st Stage Vacuum Tower Overhead Ejectors - routed to ejectors P-126A/B prior to routing to fuel gas system
- E-130 A/B/C 1st Stage Intercondensers - routed to ejectors P-126A/B prior to routing to fuel gas system.
- E-130A/B/C 1st Stage Intercondenser - venting may occur during start-up via the 4 inch block valves which are open only during start-up.
- P-126 A/B 2nd Stage Vacuum Tower Overhead Ejectors
- E-131 2nd Stage Intercondenser
- P-127 A/B 3rd Stage Vacuum Tower Overhead Ejectors
- E-132 3rd Stage Intercondenser
- D-107 Hotwell
- T-102 Vacuum Tower
- D-117 Liquid Rind Compressor Discharge Separator - processed as vent gas at VRU-300 prior to being routed to fuel gas
- D-117 Liquid Rind Compressor Discharge Separator - processed as recirculation gas at the K101A/B/C compressors prior to being routed to fuel gas
- No. 12 Pipe Still (PS) Refinery Fuel Gas System
- H-101A Process Heater
- H-101B Process Heater
- H-102 Process Heater
- South Flare and Flare System

- Flare Gas Recovery System 1 (FGRS1)

(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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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 instrumentation and heat exchange systems. As part of the WRMP Project, there will be upgrades made to various heat exchangers and associated piping and retraying of distillation towers at VRU 100 and VRU 200. The following specific units are considered to be affected facilities: [Section D.5]

- E-101A Absorber
- E-104 Sponge Oil Absorber
- F-106 Fuel Gas KO Drum
- E-102 Lean Oil Still
- F-102 Lean Oil Still Reflux Drum
- F-105 Wet Gas KO Drum
- E-103 Depropanizer
- F-103 Depropanizer Reflux Drum
- E-105A Depropanizer
- F-117 Depropanizer Overhead Accumulator
- F-101 Absorber Feed Drum
- E-106 Dethanizer
- Vapor Recovery Unit 100 (VRU 100) Refinery Fuel Gas
- E-201A Absorber
- E-204 Sponge Oil Absorber
- F-206 Fuel Gas KO Drum
- V-2A H2S Contactor
- V-2 H2S Contactor
- E-202 Lean Oil Still
- F-202 Lean Oil Still Reflux Drum
- F-205 Wet Gas KO Drum
- E-203 Depropanizer
- F-203 Depropanizer Reflux Drum
- V-2B H2S Contactor
- V-7 Amine K.O. Drum
- E-205 Depropanizer
- F-217 Depropanizer Overhead Accumulator
- F-201 Absorber Feed Drum
- Vapor Recovery Unit 200 (VRU 200) Refinery Fuel Gas System
- VRU Flare and Flare System
- Flare Gas Recovery System 3 (FGRS3)

(f) (1) 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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, there will be upgrades made to various distillation towers, compressor K-340, and associated piping at VRU 300. Upon completion of WRMP, some portions of VRU 300 will be connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.6]

- D-306 IVN Feed Drum
- T-303 Debutanizer
- D-305 Debutanizer Reflux Drum
- T-301 Depropanizer
- T-391 Sat Extractor
- D-391 Sat Feed Caustic Settler
- D-345 Absorber Feed Drum
- D-303 LVN Feed Drum
- T-302 Debutanizer
- D-302 Splitter/Debutanizer Overhead Condenser
- T-301 Depropanizer
- D-301 Depropanizer Overhead Accumulator
- T-358 Propane H2S Absorber
- D-358A Knock-Out Drum
- D-358 Coker Naphtha Feed Drum
- D-357 Compressor K.O. Drum
- D-354 Compressor Intercooler K.O. Drum
- D-351 Absorber Feed Drum
- T-352 Dehexanizer
- D-352 Dehexanizer Overhead Accumulator
- T-353 Depropanizer
- D-353 Depropanizer Overhead Condenser
- T-370 Debutanizer
- D-370 Debutanizer Overhead Accumulator
- T-390 BB Extraction Tower
- D-392 BB Knock Out Drum
- T-380 Catalytic RAN Debutanizer
- D-380 Debutanizer Overhead Accumulator
- T-351A Sponge Oil Absorber
- D-350 T-351A Knock Out Drum
- T-351B Primary Absorber
- T-351C Stripper
- T-356 Cracked Fuel Gas H2S Absorber
- D-330 Water Knock Out Drum
- T-340A Absorber
- T-340 Absorber
- T-357 Saturated Fuel Gas H2S Absorber
- D-358A Knock Out Drum
- D-312 Caustic Wash Drum
- D-313A Circ. Water Wash Drum
- D-314 Feed Surge Drum
- D-315 Coalescer
- T-304 Deethanizer
- D-304A Deethanizer Reflux Drum
- Vapor Recovery Unit 300 (VRU 300) Refinery Fuel Gas System
- VRU Flare and Flare System
- Flare Gas Recovery System 3 (FGRS3)
- South Flare and Flare System
- Flare Gas Recovery System 1 (FGRS1)

(2) Vapor Recovery Unit VRU 400 for the Coker 2, permitted in 2008, to be installed as part of the WRMP project. This unit is connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or 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 K-401), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.6]

- E-409 A/B/C/D Compressor Interstage Condensers
- D-401 Compressor Interstage Drum
- E-401 A/B/C/D Absorber Stripper Feed Condenser
- D-402 Absorber Stripper Feed Drum
- T-401 Absorber
- T-403 Sponge Adsorber
- D-408 Drum
- T-405 Coker Product Gas Amine Scrubber
- T-404 Debutanizer
- E-408A/B Debutanizer Overhead Condensers
- D-405 Debutanizer Overhead Drum
- T-406 C3/C4 Amine Contactor
- D-406 C3/C4 Amine Settler
- T-407 Splitter
- D-409 C3/C4 Splitter Overhead Drum
- D-431 Feed Surge Drum
- R-431 Di-Olefin Reactor
- R-432A Silica Reactor
- R-432B Silica Reactor
- D-432 Cold High Pressure Separator
- T-408 Naphtha Splitter
- T-441 Extractor Plus
- D-442 COS Solvent Settler
- T-442 Oxidizer
- D-444 Disulfide Separator
- TK-443 Vent Tank
- Vapor Recovery Unit 400 (VRU 400) Refinery Fuel Gas System
- South Flare and Flare System
- Flare Gas Recovery System 1 (FGRS1)

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions emitted during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.7]

- R-1 Reactor
- R-2 Reactor
- R-3 Reactor
- R-4 Reactor
- R-5 Reactor
- D-45A Fiber Film Contactor/D-45 Effluent Knockout Drum

- D-47 Effluent Caustic Wash Drum
- D-46 Effluent Water Wash Drum
- D-4 & D-5 Effluent Knock Out Drums
- T-1 Deisoobutanizer
- E-12G/12H/12I/12J T-1 Overhead Condensers
- D-1 T-1 Reflux Drum
- D-11A/B Isobutane Recycle Coalescers
- T-2 Debutanizer
- E-14A/B T-2 Overhead Condensers
- D-2 T-2 Reflux Drum
- D-12 Saturated Butane Feed Drum
- T-6 C4/C5 Splitter
- E-38A/B Splitter Condenser
- D-80 Splitter Reflux Drum
- T-5 Debutanizer
- E-36 T-5 Overhead Condenser
- D-78 T-5 Reflux Drum
- D-71 R-1 Vapor Cyclone Separator
- D-72 R-2 Vapor Cyclone Separator
- D-73 R-3 Vapor Cyclone Separator
- D-74 R-4 Vapor Cyclone Separator
- D-77 R-5 Vapor Cyclone Separator
- D-6 Compressor Knock Out Drum
- K-1 Compressor
- Refrigerant Condensers E-4A/4B/4C/4D
- D-7 Refrigerant Receiver
- D-6A Compressor Knock Out Drum
- K-1A Refrigerant Compressor
- Refrigerant Condensers E-4E/4F
- D-7A Refrigerant Receiver
- T-3 Depropanizer
- E-8 T-3 Overhead Condenser
- D-3 T-3 Reflux Drum
- T-4 Depropanizer
- E-22 T-4 Overhead Condenser
- D-14 T-4 Reflux Drum
- D-29 LPG Knock Out Drum
- D-30 LPG/Caustic Treater
- D-31 LPG/Caustic Knock Out Drum
- D-22 Alky Flare Knockout Drum
- Alkylation Unit Refinery Fuel Gas System
- Alky Flare and Flare System
- Flare Gas Recovery System 3 (FGRS3)

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control 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 the Alky Flare or FGRS3 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 and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.8]

- D-550 PCU Feed Knockout Drum
- T-115 Caustic Scrubber
- D-115 Feed Surge Drum
- D-125 T-114 Feed Coalescer
- T-114 Deethanizer
- T-101 Propylene Splitter
- D-102 Compressor Knockout Drum
- E-107 T-101 Reboiler
- D-118 PGP Selexorb Treater
- D-121 PGP Selexorb Treater
- D-120 PGP Puraspec Treater

(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 the UIU Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the MSAT II Compliance project approved in 2011 for construction, one (1) new C-250 Naphtha Splitter, a benzene saturation reactor system, and associated equipment (collectively identified as the Naphtha Splitter Unit) will be installed in the ISOM. The following specific units are considered to be affected facilities: [Section D.9]

- C-250 Naphtha Splitter
- D-38 and D-39 Feed Coalescers
- C-5 Surge Drum
- D-1 & D-2 Hydrogen Treating Reactors
- C-2 Stripper
- D-10 H2S Stripper Reflux Drum
- D-25 Sulfur Guard
- D-3 Isomerization Reactor
- D-4 Isomerization Reactor
- D-5 Isomerization Reactor
- D-6 Isomerization Reactor
- D-8 Isomerization Reactor
- D-49 Reactor Effluent Separator
- K-1 Recycle Gas Compressor
- D-50 High Pressure Separator
- D-60 Absorber Feed Mix Drum
- D-56/57/58/59 Adsorbers
- D-61 Adsorber Effluent Surge Drum
- D-11 Stabilizer Feed Drum
- C-1 Stabilizer
- D-21 Stabilizer Reflux Drum
- C-3 Stabilizer
- D-12 Stabilizer Reflux Drum
- D-23 Stabilizer Overhead Product Drum
- D-18 Flare Liquid Separator
- Isomerization Unit (ISOM) Refinery Fuel Gas System
- H-1 Process Heater
- UIU Flare and Flare System
- Flare Gas Recovery System 4 (FGRS4)

(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 following specific units are considered to be affected facilities: [Section D.10]

- C-300 Ultraformer Splitter
- D-300 UF Splitter Reflux Drum
- C-301 Xylene Fractionator
- D-301 Xylene Fractionator Reflux Drum
- C-200 SHN Splitter
- D-200 SHN Splitter Reflux Drum
- C-201 SHN Heartcut Tower
- D-201 SHN Heartcut Tower Reflux Drum
- D-203 Fuel Gas Knock Out Drum
- Aromatic Recovery Unit (ARU) Refinery Fuel Gas System
- F-200A Process Heater
- F-200B Process Heater
- 4UF Flare and Flare System
- Flare Gas Recovery System 4 (FGRS4)

(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. The BOU is connected to the 4UF Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, the BOU heater F-401 will be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr. The following specific units are considered to be affected facilities: [Section D.11]

- C-401 Feed Stripper
- D-401 Ultrafiner Reactor
- D-402 HP Separator
- D-406 HP Amine Contactor Feed Drum
- C-404 HP Amine Contactor
- D-407 Amine K.O. Drum
- D-403 Low Pressure Separator
- C-402 Product Stripper
- D-425 Water Coalescer
- J-425A and B Salt Dryers
- D-404 Product Stripper Overhead Accumulator
- D-410 Fuel Gas Drum
- C-403 Low Pressure Amine Contactor
- D-405 Amine K.O. Drum
- Blending Oil Unit (BOU) Refinery Fuel Gas System
- F-401 Process Heater
- 4UF Flare and Flare System
- Flare Gas Recovery System 4 (FGRS4)

(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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. The following specific units are considered to be affected facilities: [Section D.16]

- D-53 C-6 Feed Surge Drum
- C-6 Naphtha Splitter
- D-26 Splitter Reflux Drum
- J-4 Cat & Coker Naphtha Centrifix
- D-23 Ultrafiner Feed Charge Drum
- D-1 Ultrafiner Reactor
- D-24 Ultrafiner High Pressure Separator
- C-1A Feed Absorber/C-1B Pre-Absorber
- C-8A Amine Contactor/C-8B Water Wash
- D-30 Amine K.O. Drum
- D-9 Fuel Gas K.O. Drum
- C-5 Light Ends Stripper
- D-22 Light Ends Stripper Reflux Drum
- D-10 Prefractionator Reflux Drum
- D-3 Reactor
- D-4 Reactor
- D-5 Reactor
- D-6 Reactor
- D-7 Reactor
- D-11 Ultraformer High Pressure Separator
- C-3 Debutanizer
- D-12 Debutanizer Reflux Drum
- C-4 Depropanizer
- D-25 Depropanizer Reflux Drum
- K-1 Recycle Gas Compressor
- D-52 Chloride Guard Drum
- D-51 Chloride Guard Drum Desulfurizer
- C-7 Rerun Tower
- D-27 Rerun Reflux Drum
- D-8 Swing Reactor
- No.4 Ultraformer Unit (4 UF) Refinery Fuel Gas System
- F-1 Process Heater
- F-8A Process Heater
- F-8B Process Heater
- F-2 Process Heater
- F-3 Process Heater
- F-4 Process Heater
- F-5 Process Heater
- F-6 Process Heater
- F-7 Process Heater
- 4UF Flare and Flare System
- Flare Gas Recovery System 4 (FGRS4)

(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 following specific units are considered to be affected facilities: [Section D.17]

- D-509 Purge Gas Drum
- D-506 Fuel Gas Knock Out Drum
- Hydrogen Unit (HU) Refinery Fuel Gas System
- B-501 Process Heater

- DDU Flare and Flare System

(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 following specific units are considered to be affected facilities: [Section D.18]

- F-313 Fuel Gas K.O. Drum
- F-315 Flare K.O. Drum
- Distillate Desulfurizer Unit (DDU) Refinery Fuel Gas System
- B-301 Process Heater
- B-302 Process Heater
- DDU Flare and Flare System

(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 CFHU is connected to the No. 4 Ultraformer flare stack. The No. 4 Ultraformer Flare Stack, S/V 2224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.19]

- J-801 Cetrifix
- J-823A/B/C/D/E Backwash Filters
- Gas Oil Surge Drum D-811
- D-801A Cat Feed Unit Reactor
- D-802A Cat Feed Unit Reactor
- D-801B Cat Feed Unit Reactor
- D-802B Cat Feed Unit Reactor
- D-803 High Pressure Separator
- G-808 Power Recovery Turbine (G-801A Auxiliary Driver)
- D-804 Lower Pressure Separator
- C-801A Product Stripper
- D-807 Fuel Gas Knockout Drum
- J-805 High Pressure Separator
- E-807 Reactor Effluent Vapor Air Condenser
- E-808A/B Reactor Effluent Water Condenser
- D-805A High Pressure Vapor/Liquid Separator Drum
- Cat Feed Hydrotreating Unit (CFHU) Refinery Fuel Gas System
- F-801A Process Heater
- F-801B Process Heater
- F-801C Process Heater
- 4UF Flare and Flare System
- Flare Gas Recovery System 4 (FGRS4)

(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 following specific units are considered to be affected facilities: [Section D.20]

- J-101 Centrifugal Separator
- C-101 Absorber
- D-103 Reactor
- D-104 Reactor

- D-105 Reactor
- D-114 Reactor
- D-106 HP Separator Drum
- C-103 Stripper
- D-107 Stripper Reflux Drum Pot
- C-102 H2S Scrubber
- D-117 Fuel Gas Knock Out Drum
- Catalytic Refining Unit (CRU) Refinery Fuel Gas System
- F-101 Process Heater
- F-102A Process Heater
- UIU Flare and Flare System
- Flare Gas Recovery System 4 (FGRS4)

(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 following specific units are considered to be affected facilities: [Section D.21]

- D-1 Disengager (Reactor)
- D-3 Disengager (Reactor) Stripper
- E-1A Fractionator
- E-2 LCCO Stripper
- F-4 Gasoline Accumulator (Reflux) Drum
- F-5 and F-6 Wet Gas Knockout Drums
- F-5G Wet Gas Knockout Drum
- F-17 Low Pressure Bleed Gas Knockout Drum
- Fluidized Catalytic Cracking Unit (FCU) 500 Refinery Fuel Gas System
- VRU Flare and Flare System
- Flare Gas Recovery System 3 (FGRS3)

(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 following specific units are considered to be affected facilities: [Section D.22]

- D-1 Reactor
- D-3 Reactor Stripper
- E-1 Fractionator
- E-2 LCCO Stripper
- F-4 Fractionator Reflux Drum
- F-5 Wet Gas Knockout Drum
- F-16 High Pressured Bleed Gas Knockout Drum
- F-17 Low Pressure Fuel Gas Knockout Drum
- F-25 Flare K.O. Drum
- F-30 Compressor K.O. Drum
- F-31 K.O. Drum Level Pot
- Fluidized Catalytic Cracking Unit (FCU) 600 Refinery Fuel Gas System
- FCU Flare and Flare System
- Flare Gas Recovery System 3 (FGRS3)

(x) A portion of No. 3 Stanolind Power Station (SPS) identified as Unit ID 503. The following specific units are considered to be affected facilities: [Section D.24]

- L-124 Fuel Gas Knockout Drum
- No. 3 Stanolind Power Station (3SPS) Refinery Fuel Gas System
- #31 Boiler and Duct Burner 31
- #32 Boiler and Duct Burner 32
- #33 Boiler and Duct Burner 33
- #34 Boiler and Duct Burner 34
- #36 Boiler and Duct Burner 36

(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 WRMP Project. The following specific units are considered to be affected facilities: [Section D.42]

- D-911 Hot Feed Surge Drum
- D-901A Guard Reactor A
- D-902A DHT Reactor A
- D-901B Guard Reactor B
- D-902B DHT Reactor B
- D-903 Hot HP Separator Drum
- D-905 Cold HP Separator Drum
- D-933 Sour Water Flash Drum
- C-902 HP Amine Absorber
- D-906 Recycle Gas Knockout Drum
- D-910 H2 Make-up Knockout Drum - operating scenario #1 Process Heaters/Boilers
- D-910 H2 Make-up Knockout Drum - operating scenario #2 Flare
- D-912A Suction Snubber Drum
- D-913A Discharge Snubber Drum
- D-904 Hot MP Separator Drum
- D-916 Cold MP Separator Drum
- C-906 MP Amine Absorber Drum
- D-917 Wash Water Surge Drum
- C-901 Stripper
- D-908 Stripper Reflux Drum
- J-912 Coalescer Drum
- C-903 LP Amine Absorber Scrubber
- D-914 Flare Knockout Drum - operating scenario #1 Process Heaters/Boilers
- D-914 Flare Knockout Drum - operating scenario #2 Flare
- J-941-D1 Seal Knockout Drum
- Gas Oil Hydrotreater (GOHT) Refinery Fuel Gas System
- GOHT Flare and Flare System
- Flare Gas Recovery System 2 (FGRS2)

Under 40 CFR 65, Subpart A, the above equipment are considered affected facilities.

(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.2.1 General Provisions Relating to Consolidated Federal Air Rule [40 CFR Part 65, Subpart A]

Pursuant to 40 CFR 65, Subpart A, the Permittee shall comply with the following applicable provisions of 40 CFR Part 65, Subpart A – General Provisions (included as Attachment B.i of this permit) for the emission unit(s) listed above as specified as follows:

1. 40 CFR 65.1 (a) - (f)
2. 40 CFR 65.2
3. 40 CFR 65.3 (a)(1), (a)(3), (a)(4), (a)(5), (b)(3), (b)(5), (c), (d)
4. 40 CFR 65.4
5. 40 CFR 65.5
6. 40 CFR 65.6 (b), (c)
7. 40 CFR 65.7 (a), (b), (c), (d)
8. 40 CFR 65.9
9. Table 1
10. Table 2

SECTION E.3 Consolidated Federal Air Rule Process Vents (40 CFR 65, Subpart D)

Emissions Unit Description:

(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. The following specific units are considered to be affected facilities: [Section D.1]

- T-2 Primary Tower
- T-3C Primary Gas Oil Stripper
- T-3B Light Middle Distillate Stripper
- T-3A Heavy Naphtha Stripper
- E-3A/B/C/D T-2 Crude Tower Overhead Condenser
- D-1 Primary Tower Reflux Drum
- E-1A/E-1B Secondary Overhead Condensers
- D-9 Crude Tower Second Stage Condenser (LVN) Drum
- T-4 First Vacuum Tower
- E-18AX/BX/CX Condensers
- D-21 Hotwell
- T-5 Second Vacuum Tower
- E-35, 35A, E-36AX/BX/C Condensers
- D-26A Hotwell
- L-51 Wet Gas K.O. Drum
- D-23 Separator
- D-201 Flash Drum
- T-200 Crude Tower
- D-202 Crude Tower Reflux Drum
- D-203 Crude Tower Second Stage Condenser Drum
- T-201D PGO Stripper
- T-201C HMD Stripper
- T-201B LMD Stripper
- T-201A HVN Stripper
- T-300 Vacuum Tower
- D-300A Hotwell
- E-305 Pre Condenser
- E-305A/B/C Condensers
- K-300A/B Vent Gas Compressors
- D-301 Separator

(b) Cokers. The following specific units are considered to be affected facilities: [Section D.2]

- T-201 Coker2 Fractionator
- D-220 Fractionator Water Wash Coalescer
- D-202 Kerosene Stripper
- E-212 A/B/C/D/E/F Fractionator Overhead Condensers
- E-212 G/H/I/J/K/L Fractionator Overhead Condensers
- D-214 Fractionator Overhead Drum
- D-211 Coker2 Blowdown Drum
- D-212 Blowdown Settling Drum
- D-213 Water Seal Drum - operating scenario #1 Process Heaters /Boilers
- D-213 Water Seal Drum - operating scenario #2 Flare
- D-241 Oily Water Separator – operating scenario #1 Process Heaters/Boilers
- D-241 Oily Water Separator – operating scenario #2 Flare

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the WRMP 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 WRMP project. Also, as part of the WRMP Project, there will be upgrades made to the atmospheric and vacuum distillation towers and various heat exchangers and associated piping. The following specific units are considered to be affected facilities: [Section D.3]

- T-101 Primary Fractionator
- T-4 Primary Gasoil Stripper
- T-103B Middle Distillate Stripper
- T-103C Middle Distillate Stripper
- E120 A/B/C/D Primary Fractionator Overhead Condensers
- D-112 Primary Reflux Drum
- E137 Light Virgin Naphtha Condenser
- D-111 Wet Gas Knockout Drum
- D-3C Relief Collection Drum - operating scenario #1 Process Heaters/Boilers
- D-3C Relief Collection Drum - operating scenario #2 Flare
- P-125A/B/C 1st Stage Vacuum Tower Overhead Ejectors - release to RV manifold & flare
- P-125A/B/C 1st Stage Vacuum Tower Overhead Ejectors - release to T-102 prior to being routed to fuel gas
- P-125A/B/C 1st Stage Vacuum Tower Overhead Ejectors - routed to ejectors P-126A/B prior to routing to fuel gas system
- E-130 A/B/C 1st Stage Intercondensers - routed to ejectors P-126A/B prior to routing to fuel gas system.
- E-130A/B/C 1st Stage Intercondenser - venting may occur during start-up via the 4 inch block valves which are open only during start-up.
- P-126 A/B 2nd Stage Vacuum Tower Overhead Ejectors
- E-131 2nd Stage Intercondenser
- P-127 A/B 3rd Stage Vacuum Tower Overhead Ejectors
- E-132 3rd Stage Intercondenser
- D-107 Hotwell
- T-102 Vacuum Tower
- D-117 Liquid Rind Compressor Discharge Separator - processed as vent gas at VRU-300 prior to being routed to fuel gas
- D-117 Liquid Rind Compressor Discharge Separator - processed as recirculation gas at the K101A/B/C compressors prior to being routed to fuel gas

(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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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 instrumentation and heat exchange systems. As part of the WRMP Project, there will be upgrades made to various heat exchangers and associated piping and retraying of distillation towers at VRU 100 and VRU 200. The following specific units are considered to be affected facilities: [Section D.5]

- E-101A Absorber
- E-104 Sponge Oil Absorber
- F-106 Fuel Gas KO Drum
- E-101A Absorber
- E-102 Lean Oil Still

- F-102 Lean Oil Still Reflux Drum
- F-105 Wet Gas KO Drum
- E-103 Depropanizer
- F-103 Depropanizer Reflux Drum
- E-105A Depropanizer
- F-117 Depropanizer Overhead Accumulator
- F-101 Absorber Feed Drum
- E-106 Dethanizer
- E-201A Absorber
- E-204 Sponge Oil Absorber
- V-2A H2S Contactor
- V-2 H2S Contactor
- E-202 Lean Oil Still
- F-202 Lean Oil Still Reflux Drum
- F-205 Wet Gas KO Drum
- E-203 Depropanizer
- F-203 Depropanizer Reflux Drum
- V-2B H2S Contactor
- V-7 Amine K.O. Drum
- E-205 Depropanizer
- F-217 Depropanizer Overhead Accumulator
- F-201 Absorber Feed Drum

(f) (1) 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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, there will be upgrades made to various distillation towers, compressor K-340, and associated piping at VRU 300. Upon completion of WRMP, some portions of VRU 300 will be connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.6]

- D-306 IVN Feed Drum
- T-303 Debutanizer
- D-305 Debutanizer Reflux Drum
- T-301 Depropanizer
- T-391 Sat Extractor
- D-391 Sat Feed Caustic Settler
- D-345 Absorber Feed Drum
- D-303 LVN Feed Drum
- T-302 Debutanizer
- D-302 Splitter/Debutanizer Overhead Condenser
- T-301 Depropanizer
- D-301 Depropanizer Overhead Accumulator
- T-358 Propane H2S Absorber
- D-358A Knock-Out Drum
- D-358 Coker Naphtha Feed Drum
- D-357 Compressor K.O. Drum
- D-354 Compressor Intercooler K.O. Drum
- D-351 Absorber Feed Drum
- T-352 Dehexanizer

- D-352 Dehexanizer Overhead Accumulator
- T-353 Depropanizer
- D-353 Depropanizer Overhead Condenser
- T-370 Debutanizer
- D-370 Debutanizer Overhead Accumulator
- T-390 BB Extraction Tower
- D-392 BB Knock Out Drum
- T-380 Catalytic RAN Debutanizer
- D-380 Debutanizer Overhead Accumulator
- T-351A Sponge Oil Absorber
- D-350 T-351A Knock Out Drum
- T-351B Primary Absorber
- T-351C Stripper
- T-356 Cracked Fuel Gas H2S Absorber
- D-330 Water Knock Out Drum
- T-340A Absorber
- T-340 Absorber
- T-357 Saturated Fuel Gas H2S Absorber
- D-358A Knock Out Drum
- D-312 Caustic Wash Drum
- D-313A Circ. Water Wash Drum
- D-314 Feed Surge Drum
- D-315 Coalescer
- T-304 Deethanizer
- D-304A Deethanizer Reflux Drum

(2) Vapor Recovery Unit VRU 400 for the Coker 2, permitted in 2008, to be installed as part of the WRMP project. This unit is connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or 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 K-401), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.6]

- E-409 A/B/C/D Compressor Interstage Condensers
- D-401 Compressor Interstage Drum
- E-401 A/B/C/D Absorber Stripper Feed Condenser
- D-402 Absorber Stripper Feed Drum
- T-401 Absorber
- T-403 Sponge Adsorber
- D-408 Drum
- T-405 Coker Product Gas Amine Scrubber
- T-404 Debutanizer
- E-408A/B Debutanizer Overhead Condensers
- D-405 Debutanizer Overhead Drum
- T-406 C3/C4 Amine Contactor
- D-406 C3/C4 Amine Settler
- T-407 Splitter
- D-409 C3/C4 Splitter Overhead Drum
- D-431 Feed Surge Drum
- R-431 Di-Olefin Reactor
- R-432A Silica Reactor
- R-432B Silica Reactor

- D-432 Cold High Pressure Separator
- T-408 Naphtha Splitter
- T-441 Extractor Plus
- D-442 COS Solvent Settler
- T-442 Oxidizer
- D-444 Disulfide Separator
- TK-443 Vent Tank

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions emitted during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.7]

- R-1 Reactor
- R-2 Reactor
- R-3 Reactor
- R-4 Reactor
- R-5 Reactor
- D-45A Fiber Film Contactor/D-45 Effluent Knockout Drum
- D-47 Effluent Caustic Wash Drum
- D-46 Effluent Water Wash Drum
- D-4 & D-5 Effluent Knock Out Drums
- T-1 Deisoobutanizer
- E-12G/12H/12I/12J T-1 Overhead Condensers
- D-1 T-1 Reflux Drum
- D-11A/B Isobutane Recycle Coalescers
- T-2 Debutanizer
- E-14A/B T-2 Overhead Condensers
- D-2 T-2 Reflux Drum
- D-12 Saturated Butane Feed Drum
- T-6 C4/C5 Splitter
- E-38A/B Splitter Condenser
- D-80 Splitter Reflux Drum
- T-5 Debutanizer
- E-36 T-5 Overhead Condenser
- D-78 T-5 Reflux Drum
- D-71 R-1 Vapor Cyclone Separator
- D-72 R-2 Vapor Cyclone Separator
- D-73 R-3 Vapor Cyclone Separator
- D-74 R-4 Vapor Cyclone Separator
- D-77 R-5 Vapor Cyclone Separator
- D-6 Compressor Knock Out Drum
- K-1 Compressor
- Refrigerant Condensers E-4A/4B/4C/4D
- D-7 Refrigerant Receiver
- D-6A Compressor Knock Out Drum
- K-1A Refrigerant Compressor
- Refrigerant Condensers E-4E/4F
- D-7A Refrigerant Receiver
- T-3 Depropanizer
- E-8 T-3 Overhead Condenser
- D-3 T-3 Reflux Drum

- T-4 Depropanizer
- E-22 T-4 Overhead Condenser
- D-14 T-4 Reflux Drum
- D-29 LPG Knock Out Drum
- D-30 LPG/Caustic Treater
- D-31 LPG/Caustic Knock Out Drum

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control 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 the Alky Flare or FGRS3 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 and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.8]

- D-550 PCU Feed Knockout Drum
- T-115 Caustic Scrubber
- D-115 Feed Surge Drum
- D-125 T-114 Feed Coalescer
- T-114 Deethanizer
- T-101 Propylene Splitter
- D-102 Compressor Knockout Drum
- E-107 T-101 Reboiler
- D-118 PGP Selexorb Treater
- D-121 PGP Selexorb Treater
- D-120 PGP Puraspec Treater

(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 the UIU Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the MSAT II Compliance project approved in 2011 for construction, one (1) new C-250 Naphtha Splitter, a benzene saturation reactor system, and associated equipment (collectively identified as the Naphtha Splitter Unit) will be installed in the ISOM. The following specific units are considered to be affected facilities: [Section D.9]

- C-250 Naphtha Splitter
- D-38 and D-39 Feed Coalescers
- C-5 Surge Drum
- D-1 & D-2 Hydrogen Treating Reactors
- C-2 Stripper
- D-10 H2S Stripper Reflux Drum
- D-25 Sulfur Guard
- D-3 Isomerization Reactor
- D-4 Isomerization Reactor
- D-5 Isomerization Reactor
- D-6 Isomerization Reactor
- D-8 Isomerization Reactor
- D-49 Reactor Effluent Separator
- K-1 Recycle Gas Compressor

- D-50 High Pressure Separator
- D-60 Absorber Feed Mix Drum
- D-56/57/58/59 Adsorbers
- D-61 Adsorber Effluent Surge Drum
- D-11 Stabilizer Feed Drum
- C-1 Stabilizer
- D-21 Stabilizer Reflux Drum
- C-3 Stabilizer
- D-12 Stabilizer Reflux Drum
- D-23 Stabilizer Overhead Product Drum
- D-18 Flare Liquid Separator

(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 following specific units are considered to be affected facilities: [Section D.10]

- C-300 Ultraformer Splitter
- D-300 UF Splitter Reflux Drum
- C-301 Xylene Fractionator
- D-301 Xylene Fractionator Reflux Drum
- C-200 SHN Splitter
- D-200 SHN Splitter Reflux Drum
- C-201 SHN Heartcut Tower
- D-201 SHN Heartcut Tower Reflux Drum

(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. The BOU is connected to the 4UF Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, the BOU heater F-401 will be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr. The following specific units are considered to be affected facilities: [Section D.11]

- C-401 Feed Stripper
- D-401 Ultrafiner Reactor
- D-402 HP Separator
- D-406 HP Amine Contactor Feed Drum
- C-404 HP Amine Contactor
- D-407 Amine K.O. Drum
- D-403 Low Pressure Separator
- C-402 Product Stripper
- D-425 Water Coalescer
- J-425A and B Salt Dryers
- D-404 Product Stripper Overhead Accumulator
- C-403 Low Pressure Amine Contactor
- D-405 Amine K.O. Drum

(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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. The following specific units are considered to be affected facilities: [Section D.16]

- D-53 C-6 Feed Surge Drum
- C-6 Naphtha Splitter
- D-26 Splitter Reflux Drum
- J-4 Cat & Coker Naphtha Centrifix
- D-23 Ultrafiner Feed Charge Drum
- D-1 Ultrafiner Reactor
- D-24 Ultrafiner High Pressure Separator
- C-1A Feed Absorber/C-1B Pre-Absorber
- C-8A Amine Contactor/C-8B Water Wash
- D-30 Amine K.O. Drum
- C-5 Light Ends Stripper
- D-22 Light Ends Stripper Reflux Drum
- D-10 Prefractionator Reflux Drum
- D-3 Reactor
- D-4 Reactor
- D-5 Reactor
- D-6 Reactor
- D-7 Reactor
- D-11 Ultraformer High Pressure Separator
- C-3 Debutanizer
- D-12 Debutanizer Reflux Drum
- C-4 Depropanizer
- D-25 Depropanizer Reflux Drum
- K-1 Recycle Gas Compressor
- D-52 Chloride Guard Drum
- D-51 Chloride Guard Drum Desulfurizer
- C-7 Rerun Tower
- D-27 Rerun Reflux Drum
- D-8 Swing Reactor

(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 following specific units are considered to be affected facilities: [Section D.17]

- D-509 Purge Gas Drum

(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 CFHU is connected to the No. 4 Ultraformer flare stack. The No. 4 Ultraformer Flare Stack, S/V 2224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.19]

- J-801 Cetrifix
- J-823A/B/C/D/E Backwash Filters
- Gas Oil Surge Drum D-811
- D-801A Cat Feed Unit Reactor
- D-802A Cat Feed Unit Reactor

- D-801B Cat Feed Unit Reactor
- D-802B Cat Feed Unit Reactor
- D-803 High Pressure Separator
- G-808 Power Recovery Turbine (G-801A Auxiliary Driver)
- D-804 Lower Pressure Separator
- C-801A Product Stripper
- J-805 High Pressure Separator
- E-807 Reactor Effluent Vapor Air Condenser
- E-808A/B Reactor Effluent Water Condenser
- D-805A High Pressure Vapor/Liquid Separator Drum

(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 following specific units are considered to be affected facilities: [Section D.20]

- J-101 Centrifugal Separator
- C-101 Absorber
- D-103 Reactor
- D-104 Reactor
- D-105 Reactor
- D-114 Reactor
- D-106 HP Separator Drum
- C-103 Stripper
- D-107 Stripper Reflux Drum Pot
- C-102 H2S Scrubber
- D-117 Fuel Gas Knock Out Drum

(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 following specific units are considered to be affected facilities: [Section D.21]

- D-1 Disengager (Reactor)
- D-3 Disengager (Reactor) Stripper
- E-1A Fractionator
- E-2 LCCO Stripper
- F-4 Gasoline Accumulator (Reflux) Drum
- F-5 and F-6 Wet Gas Knockout Drums
- F-5G Wet Gas Knockout Drum
- F-17 Low Pressure Bleed Gas Knockout Drum

(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 following specific units are considered to be affected facilities: [Section D.22]

- D-1 Reactor
- D-3 Reactor Stripper

- E-1 Fractionator
- E-2 LCCO Stripper
- F-4 Fractionator Reflux Drum
- F-5 Wet Gas Knockout Drum
- F-16 High Pressured Bleed Gas Knockout Drum
- F-17 Low Pressure Fuel Gas Knockout Drum
- F-30 Compressor K.O. Drum
- F-31 K.O. Drum Level Pot

(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 WRMP Project. The following specific units are considered to be affected facilities: [Section D.42]

- D-911 Hot Feed Surge Drum
- D-901A Guard Reactor A
- D-902A DHT Reactor A
- D-901B Guard Reactor B
- D-902B DHT Reactor B
- D-903 Hot HP Separator Drum
- D-905 Cold HP Separator Drum
- D-933 Sour Water Flash Drum
- C-902 HP Amine Absorber
- D-906 Recycle Gas Knockout Drum
- D-910 H2 Make-up Knockout Drum - operating scenario #1 Process Heaters/Boilers
- D-910 H2 Make-up Knockout Drum - operating scenario #2 Flare
- D-912A Suction Snubber Drum
- D-913A Discharge Snubber Drum
- D-904 Hot MP Separator Drum
- D-916 Cold MP Separator Drum
- C-906 MP Amine Absorber Drum
- D-917 Wash Water Surge Drum
- C-901 Stripper
- D-908 Stripper Reflux Drum
- J-912 Coalescer Drum
- C-903 LP Amine Absorber Scrubber
- J-941-D1 Seal Knockout Drum

Under 40 CFR 65, Subpart D, the above equipment is considered affected facilities.

(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.3.1 Consolidated Federal Air Rule Process Vents [40 CFR Part 65, Subpart D]

Pursuant to 40 CFR 65, Subpart D, the Permittee shall comply with the following applicable provisions of 40 CFR Part 65, Subpart D – Process Vents (included as Attachment B.ii of this permit), for the emission unit(s) listed above as specified as follows:

1. 40 CFR 65.60
2. 40 CFR 65.61
3. 40 CFR 65.62 (a), (b)(1)

4. 40 CFR 65.63 (a)(1), (a)(2)

SECTION E.4 Consolidated Federal Air Rule Closed Vent Systems, Control Devices, and Routing to a Fuel Gas System or a Process (40 CFR 65, Subpart G)

Emissions Unit Description:

(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. The following specific units are considered to be affected facilities: [Section D.1]

- E-3A/B/C/D T-2 Crude Tower Overhead Condenser
- D-1 Primary Tower Reflux Drum
- E-1A/E-1B Secondary Overhead Condensers
- D-9 Crude Tower Second Stage Condenser (LVN) Drum
- D-22 Fuel Gas K.O. Drum
- E-18AX/BX/CX Condensers
- D-21 Hotwell
- E-35, 35A, E-36AX/BX/C Condensers
- D-26A Hotwell
- L-51 Wet Gas K.O. Drum
- D-23 Separator
- D-201 Flash Drum
- D-202 Crude Tower Reflux Drum
- D-203 Crude Tower Second Stage Condenser Drum
- D-300A Hotwell
- E-305 Pre Condenser
- E-305A/B/C Condensers
- K-300A/B Vent Gas Compressors
- D-301 Separator
- D-204A Fuel Gas Knock Out Drum
- Nos. 11A and 11C Pipe Stills Refinery Fuel Gas System
- H-1X Process Heater
- H-2 Process Heater
- H-3 Process Heater
- H-200 Process Heater
- H-300 Process Heater

(b) Cokers. The following specific units are considered to be affected facilities: [Section D.2]

- D-220 Fractionator Water Wash Coalescer
- E-212 A/B/C/D/E/F Fractionator Overhead Condensers
- E-212 G/H/I/J/K/L Fractionator Overhead Condensers
- D-214 Fractionator Overhead Drum
- D-211 Coker2 Blowdown Drum
- D-212 Blowdown Settling Drum
- D-213 Water Seal Drum - operating scenario #1 Process Heaters /Boilers
- D-213 Water Seal Drum - operating scenario #2 Flare
- D-241 Oily Water Separator – operating scenario #1 Process Heaters/Boilers
- D-241 Oily Water Separator – operating scenario #2 Flare
- Coker 2 Refinery Fuel Gas System
- F-201 Process Heater
- F-202 Process Heater
- F-203 Process Heater
- South Flare and Flare System
- Flare Gas Recovery System 1 (FGRS1)

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the WRMP 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 WRMP project. Also, as part of the WRMP Project, there will be upgrades made to the atmospheric and vacuum distillation towers and various heat exchangers and associated piping. The following specific units are considered to be affected facilities: [Section D.3]

- E120 A/B/C/D Primary Fractionator Overhead Condensers
- D-112 Primary Reflux Drum
- E137 Light Virgin Naphtha Condenser
- D-111 Wet Gas Knockout Drum
- D-116 Fuel Gas Knockout Drum
- D-3C Relief Collection Drum - operating scenario #1 Process Heaters/Boilers
- D-3C Relief Collection Drum - operating scenario #2 Flare
- P-125A/B/C 1st Stage Vacuum Tower Overhead Ejectors - release to RV manifold & flare
- P-125A/B/C 1st Stage Vacuum Tower Overhead Ejectors - release to T-102 prior to being routed to fuel gas
- P-125A/B/C 1st Stage Vacuum Tower Overhead Ejectors - routed to ejectors P-126A/B prior to routing to fuel gas system
- E-130 A/B/C 1st Stage Intercondensers - routed to ejectors P-126A/B prior to routing to fuel gas system.
- E-130A/B/C 1st Stage Intercondenser - venting may occur during start-up via the 4 inch block valves which are open only during start-up.
- P-126 A/B 2nd Stage Vacuum Tower Overhead Ejectors
- E-131 2nd Stage Intercondenser
- P-127 A/B 3rd Stage Vacuum Tower Overhead Ejectors
- E-132 3rd Stage Intercondenser
- D-107 Hotwell
- D-117 Liquid Rind Compressor Discharge Separator - processed as vent gas at VRU-300 prior to being routed to fuel gas
- D-117 Liquid Rind Compressor Discharge Separator - processed as recirculation gas at the K101A/B/C compressors prior to being routed to fuel gas
- No. 12 Pipe Still Refinery Fuel Gas System and Flare Gas Recovery System
- H-101A Process Heater
- H-101B Process Heater
- H-102 Process Heater
- South Flare and Flare System
- Flare Gas Recovery System 1 (FGRS1)

(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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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 instrumentation and heat exchange systems. As part of the WRMP Project, there will be upgrades made to various heat exchangers and associated piping and retraying of distillation towers at VRU 100 and VRU 200. The following specific units are considered to be affected facilities: [Section D.5]

- F-106 Fuel Gas KO Drum
- E-102 Lean Oil Still
- F-102 Lean Oil Still Reflux Drum
- F-105 Wet Gas KO Drum
- F-103 Depropanizer Reflux Drum
- F-117 Depropanizer Overhead Accumulator
- F-101 Absorber Feed Drum
- Vapor Recovery Unit 100 (VRU 100) Refinery Fuel Gas System and Flare Gas Recovery System
- VRU Flare and Flare System
- Flare Gas Recovery System 3 (FGRS3)
- F-206 Fuel Gas KO Drum
- V-2A H2S Contactor
- V-2 H2S Contactor
- F-202 Lean Oil Still Reflux Drum
- F-205 Wet Gas KO Drum
- F-203 Depropanizer Reflux Drum
- V-2B H2S Contactor
- V-7 Amine K.O. Drum
- F-217 Depropanizer Overhead Accumulator
- F-201 Absorber Feed Drum
- Vapor Recovery Unit 200 (VRU 200) Refinery Fuel Gas System
- VRU Flare and Flare System
- Flare Gas Recovery System 3 (FGRS3)

(f) (1) 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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, there will be upgrades made to various distillation towers, compressor K-340, and associated piping at VRU 300. Upon completion of WRMP, some portions of VRU 300 will be connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.6]

- D-306 IVN Feed Drum
- D-305 Debutanizer Reflux Drum
- D-391 Sat Feed Caustic Settler
- D-345 Absorber Feed Drum
- D-303 LVN Feed Drum
- D-302 Splitter/Debutanizer Overhead Condenser
- D-301 Depropanizer Overhead Accumulator
- T-358 Propane H2S Absorber
- D-358A Knock-Out Drum
- D-358 Coker Naphtha Feed Drum
- D-357 Compressor K.O. Drum
- D-354 Compressor Intercooler K.O. Drum
- D-351 Absorber Feed Drum
- D-352 Dehexanizer Overhead Accumulator
- D-353 Depropanizer Overhead Condenser
- D-370 Debutanizer Overhead Accumulator
- D-392 BB Knock Out Drum

- D-380 Debutanizer Overhead Accumulator
- D-350 T-351A Knock Out Drum
- T-356 Cracked Fuel Gas H2S Absorber
- D-330 Water Knock Out Drum
- T-357 Saturated Fuel Gas H2S Absorber
- D-358A Knock Out Drum
- D-312 Caustic Wash Drum
- D-313A Circ. Water Wash Drum
- D-314 Feed Surge Drum
- D-315 Coalescer
- D-304A Deethanizer Reflux Drum
- Vapor Recovery Unit 300 (VRU 300) Refinery Fuel Gas System
- VRU Flare and Flare System
- Flare Gas Recovery System 3 (FGRS3)
- South Flare and Flare System
- Flare Gas Recovery System 1 (FGRS1)

(2) Vapor Recovery Unit VRU 400 for the Coker 2, permitted in 2008, to be installed as part of the WRMP project. This unit is connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or 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 K-401), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.6]

- E-409 A/B/C/D Compressor Interstage Condensers
- D-401 Compressor Interstage Drum
- E-401 A/B/C/D Absorber Stripper Feed Condenser
- D-402 Absorber Stripper Feed Drum
- D-408 Drum
- E-408A/B Debutanizer Overhead Condensers
- D-405 Debutanizer Overhead Drum
- D-406 C3/C4 Amine Settler
- D-409 C3/C4 Splitter Overhead Drum
- D-431 Feed Surge Drum
- D-432 Cold High Pressure Separator
- D-442 COS Solvent Settler
- D-444 Disulfide Separator
- TK-443 Vent Tank
- Vapor Recovery Unit 400 (VRU 400) Refinery Fuel Gas System
- South Flare and Flare System
- Flare Gas Recovery System 1 (FGRS1)

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions emitted during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.7]

- D-45A Fiber Film Contactor/D-45 Effluent Knockout Drum
- D-47 Effluent Caustic Wash Drum

- D-46 Effluent Water Wash Drum
- D-4 & D-5 Effluent Knock Out Drums
- E-12G/12H/12I/12J T-1 Overhead Condensers
- D-1 T-1 Reflux Drum
- D-11A/B Isobutane Recycle Coalescers
- E-14A/B T-2 Overhead Condensers
- D-2 T-2 Reflux Drum
- D-12 Saturated Butane Feed Drum
- E-38A/B Splitter Condenser
- D-80 Splitter Reflux Drum
- E-36 T-5 Overhead Condenser
- D-78 T-5 Reflux Drum
- D-6 Compressor Knock Out Drum
- K-1 Compressor
- Refrigerant Condensers E-4A/4B/4C/4D
- D-7 Refrigerant Receiver
- D-6A Compressor Knock Out Drum
- K-1A Refrigerant Compressor
- Refrigerant Condensers E-4E/4F
- D-7A Refrigerant Receiver
- E-8 T-3 Overhead Condenser
- D-3 T-3 Reflux Drum
- E-22 T-4 Overhead Condenser
- D-14 T-4 Reflux Drum
- D-29 LPG Knock Out Drum
- D-30 LPG/Caustic Treater
- D-31 LPG/Caustic Knock Out Drum
- D-22 Alky Flare Knockout Drum
- Alkylation Unit Refinery Fuel Gas System
- Alky Flare and Flare System
- Flare Gas Recovery System 3 (FGRS3)

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control 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 the Alky Flare or FGRS3 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 and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.8]

- D-550 PCU Feed Knockout Drum
- T-115 Caustic Scrubber
- D-115 Feed Surge Drum
- D-125 T-114 Feed Coalescer
- D-102 Compressor Knockout Drum
- E-107 T-101 Reboiler
- D-118 PGP Selexorb Treater
- D-121 PGP Selexorb Treater
- D-120 PGP Puraspec Treater
- Propylene Concentration Unit (PCU) Refinery Fuel Gas System
- Alky Flare and Flare System
- Flare Gas Recovery System 3 (FGRS3)

(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 the UIU Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the MSAT II Compliance project approved in 2011 for construction, one (1) new C-250 Naphtha Splitter, a benzene saturation reactor system, and associated equipment (collectively identified as the Naphtha Splitter Unit) will be installed in the ISOM. The following specific units are considered to be affected facilities: [Section D.9]

- D-38 and D-39 Feed Coalescers
- C-5 Surge Drum
- D-10 H2S Stripper Reflux Drum
- D-25 Sulfur Guard
- K-1 Recycle Gas Compressor
- D-60 Absorber Feed Mix Drum
- D-61 Adsorber Effluent Surge Drum
- D-11 Stabilizer Feed Drum
- D-21 Stabilizer Reflux Drum
- D-12 Stabilizer Reflux Drum
- D-23 Stabilizer Overhead Product Drum
- D-18 Flare Liquid Separator
- Isomerization Unit (ISOM) Refinery Fuel Gas System
- H-1 Process Heater
- UIU Flare and Flare System
- Flare Gas Recovery System 4 (FGRS4)

(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 following specific units are considered to be affected facilities: [Section D.10]

- D-300 UF Splitter Reflux Drum
- D-301 Xylene Fractionator Reflux Drum
- D-200 SHN Splitter Reflux Drum
- D-201 SHN Heartcut Tower Reflux Drum
- D-203 Fuel Gas Knock Out Drum
- Aromatic Recovery Unit (ARU) Refinery Fuel Gas System
- F-200A Process Heater
- F-200B Process Heater
- 4UF Flare and Flare System
- Flare Gas Recovery System 4 (FGRS4)

(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. The BOU is connected to the 4UF Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, the BOU heater F-401 will be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr. The following specific units are considered to be affected facilities: [Section D.11]

- D-406 HP Amine Contactor Feed Drum
- C-404 HP Amine Contactor
- D-407 Amine K.O. Drum
- D-425 Water Coalescer
- J-425A and B Salt Dryers
- D-404 Product Stripper Overhead Accumulator
- D-410 Fuel Gas Drum
- C-403 Low Pressure Amine Contactor
- D-405 Amine K.O. Drum
- Blending Oil Unit (BOU) Refinery Fuel Gas System
- F-401 Process Heater
- 4UF Flare and Flare System
- Flare Gas Recovery System 4 (FGRS4)

(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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. The following specific units are considered to be affected facilities: [Section D.16]

- D-53 C-6 Feed Surge Drum
- D-26 Splitter Reflux Drum
- J-4 Cat & Coker Naphtha Centrifix
- D-23 Ultrafiner Feed Charge Drum
- D-24 Ultrafiner High Pressure Separator
- C-8A Amine Contactor/C-8B Water Wash
- D-30 Amine K.O. Drum
- D-9 Fuel Gas K.O. Drum
- D-22 Light Ends Stripper Reflux Drum
- D-10 Prefractionator Reflux Drum
- D-11 Ultraformer High Pressure Separator
- D-12 Debutanizer Reflux Drum
- D-25 Depropanizer Reflux Drum
- K-1 Recycle Gas Compressor
- D-52 Chloride Guard Drum
- D-51 Chloride Guard Drum Desulfurizer
- D-27 Rerun Reflux Drum
- No.4 Ultraformer Unit (4 UF) Refinery Fuel Gas System
- F-1 Process Heater
- F-8A Process Heater
- F-8B Process Heater
- F-2 Process Heater
- F-3 Process Heater
- F-4 Process Heater
- F-5 Process Heater
- F-6 Process Heater
- F-7 Process Heater
- 4UF Flare and Flare System
- Flare Gas Recovery System 4 (FGRS4)

(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 following specific units are considered to be affected facilities: [Section D.17]

- D-509 Purge Gas Drum
- D-506 Fuel Gas Knock Out Drum
- Hydrogen Unit (HU) Refinery Fuel Gas System
- B-501 Process Heater
- DDU Flare and Flare System

(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 following specific units are considered to be affected facilities: [Section D.18]

- F-313 Fuel Gas K.O. Drum
- F-315 Flare K.O. Drum
- Distillate Desulfurizer Unit (DDU) Refinery Fuel Gas System
- B-301 Process Heater
- B-302 Process Heater
- DDU Flare and Flare System

(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 CFHU is connected to the No. 4 Ultraformer flare stack. The No. 4 Ultraformer Flare Stack, S/V 2224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.19]

- J-801 Cetrifix
- J-823A/B/C/D/E Backwash Filters
- Gas Oil Surge Drum D-811
- D-803 High Pressure Separator
- G-808 Power Recovery Turbine (G-801A Auxiliary Driver)
- D-804 Lower Pressure Separator
- D-807 Fuel Gas Knockout Drum
- E-807 Reactor Effluent Vapor Air Condenser
- E-808A/B Reactor Effluent Water Condenser
- D-805A High Pressure Vapor/Liquid Separator Drum
- Cat Feed Hydrotreating Unit (CFHU) Refinery Fuel Gas System
- F-801A Process Heater
- F-801B Process Heater
- F-801C Process Heater
- 4UF Flare and Flare System
- Flare Gas Recovery System 4 (FGRS4)

(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 following specific units are considered to be affected facilities: [Section D.20]

- J-101 Centrifugal Separator
- D-106 HP Separator Drum
- D-107 Stripper Reflux Drum Pot
- C-102 H2S Scrubber
- D-117 Fuel Gas Knock Out Drum
- Catalytic Refining Unit (CRU) Refinery Fuel Gas System
- F-101 Process Heater
- F-102A Process Heater
- UIU Flare and Flare System
- Flare Gas Recovery System 4 (FGRS4)

(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 following specific units are considered to be affected facilities: [Section D.21]

- F-4 Gasoline Accumulator (Reflux) Drum
- F-5 and F-6 Wet Gas Knockout Drums
- F-5G Wet Gas Knockout Drum
- F-17 Low Pressure Bleed Gas Knockout Drum
- Fluidized Catalytic Cracking Unit (FCU) 500 Refinery Fuel Gas System
- VRU Flare and Flare System
- Flare Gas Recovery System 3 (FGRS3)

(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 following specific units are considered to be affected facilities: [Section D.22]

- F-4 Fractionator Reflux Drum
- F-5 Wet Gas Knockout Drum
- F-16 High Pressured Bleed Gas Knockout Drum
- F-17 Low Pressure Fuel Gas Knockout Drum
- F-25 Flare K.O. Drum
- F-30 Compressor K.O. Drum
- F-31 K.O. Drum Level Pot
- Fluidized Catalytic Cracking Unit (FCU) 600 Refinery Fuel Gas System
- FCU Flare and Flare System
- Flare Gas Recovery System 3 (FGRS3)

(x) A portion of No. 3 Stanolind Power Station (SPS) identified as Unit ID 503. The following specific units are considered to be affected facilities: [Section D.24]

- L-124 Fuel Gas Knockout Drum
- No. 3 Stanolind Power Station (3SPS) Refinery Fuel Gas System
- #31 Boiler and Duct Burner 31
- #32 Boiler and Duct Burner 32
- #33 Boiler and Duct Burner 33
- #34 Boiler and Duct Burner 34
- #36 Boiler and Duct Burner 36

(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 WRMP Project. The following specific units are considered to be affected facilities: [Section D.42]

- D-911 Hot Feed Surge Drum
- D-933 Sour Water Flash Drum
- D-906 Recycle Gas Knockout Drum
- D-910 H2 Make-up Knockout Drum - operating scenario #1 Process Heaters/Boilers
- D-910 H2 Make-up Knockout Drum - operating scenario #2 Flare
- D-912A Suction Snubber Drum
- D-913A Discharge Snubber Drum
- D-917 Wash Water Surge Drum
- D-908 Stripper Reflux Drum
- J-912 Coalescer Drum
- D-914 Flare Knockout Drum - operating scenario #1 Process Heaters/Boilers
- D-914 Flare Knockout Drum - operating scenario #2 Flare
- J-941-D1 Seal Knockout Drum
- Gas Oil Hydrotreater (GOHT) Refinery Fuel Gas System
- GOHT Flare and Flare System
- Flare Gas Recovery System 2 (FGRS2)

Under 40 CFR 65, Subpart G, the above equipment are considered affected facilities.

(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.4.1 Consolidated Federal Air Rule Closed Vent Systems, Control Devices, and Routing to a Fuel Gas System or a Process [40 CFR Part 65, Subpart G]

Pursuant to 40 CFR 65, Subpart G, the Permittee shall comply with the following applicable provisions of 40 CFR Part 65, Subpart G – Closed Vent Systems, Control Devices, and Routing to a Fuel Gas System or a Process (included as Attachment B.iii of this permit) for the emission unit(s) listed above as specified as follows:

1. 40 CFR 65.140
2. 40 CFR 65.141
3. 40 CFR 65.142 (b)(1), (b)(2)
4. 40 CFR 65.143 (a)(1), (a)(2), (a)(3)
5. 40 CFR 65.147 (a), (b), (c)
6. 40 CFR 65.149 (a), (b)(2)(i) - (ii)
7. 40 CFR 65.156 (a)(2)
8. 40 CFR 65.157
9. 40 CFR 65.159
10. 40 CFR 65.160 (a), (b)(1)(iv)
11. 40 CFR 65.163 (a)(1), (c)
12. 40 CFR 65.164
13. 40 CFR 65.166 (a), (b)(2), (b)(3), (c)
14. 40 CFR 65.167 (b)

SECTION F.1 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart Dc

Emissions Unit Description:

(d) The Sulfur Recovery Plant (SRP), 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 WRMP Project, increasing the capacity to 1,300 long tons per day of sulfur. Additional sulfur capacity can be achieved with oxygen enrichment in the C, D and E Claus trains as part of the original WRMP design with no increase in permitted emissions. The following specific units are considered to be affected facilities: [Section D.4]

- Tail Gas units (TGU), identified as TGU A and TGU B

(x) A portion of No. 3 Stanolind Power Station (SPS) identified as Unit ID 503. The following specific units are considered to be affected facilities: [Section D.24]

- Five (5) direct-fired duct burners

Under 40 CFR Part 60, Subpart Dc, the above units are affected facilities.

(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)]

F.1.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1][40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Dc.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

F.1.2 Standard of Performance for Small Industrial-Commercial-Institutional Steam Generating Units [326 IAC 12-1][40 CFR 60, Subpart Dc]

Pursuant to 40 CFR Part 60, Subpart Dc, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart Dc, which are incorporated by reference as 326 IAC 12 (included as Attachment C.i to this permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.40c (a), (b), (c), (e), (h), (i)
2. 40 CFR 60.41c
3. 40 CFR 60.48c (a), (f)(4), (g), (i), (j)

SECTION F.2 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart J

Emissions Unit Description:

(bb) The general facility remediation system, identified as Unit 999. Remediation includes multiple well point systems. The well point systems extract groundwater which may have a small hydrocarbon fraction. 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. The following specific units are considered to be affected facilities: [Section D.28]

- Thermal Oxidizer (ITF)

(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 following specific units are considered to be affected facilities: [Section D.30]

- Vapor Combustion Unit (identified as VCU).

(oo) The New Hydrogen Unit (New HU), identified as Unit ID 801, owned and operated by Praxair, Inc. and constructed as part of the WRMP 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 NO_X. The New HU heater stacks have continuous emissions monitors (CEMs) for NO_X and CO. The following specific units are considered to be affected facilities: [Section D.43]

- New HU Flare

Under 40 CFR Part 60, Subpart J, the above units are affected facilities.

(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)]

F.2.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1][40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart J.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

F.2.2 Standard of Performance for Petroleum Refineries [326 IAC 12-1][40 CFR 60, Subpart J]

Pursuant to 40 CFR Part 60, Subpart J, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart J, which are incorporated by reference as 326 IAC 12 (included as Attachment C.ii to this permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.100
2. 40 CFR 60.101
3. 40 CFR 60.104 (a)
4. 40 CFR 60.105 (a)(4), (b), (e)(3)(ii)
5. 40 CFR 60.106 (a), (e)(1)
6. 40 CFR 60.107 (d), (e), (f), (g)
7. 40 CFR 60.109

F.2.3 Compliance Monitoring Requirements for the Vapor Combustion Unit [326 IAC 12][40 CFR 60, Subpart J]

To demonstrate compliance Condition F.2.2 and as approved by the U.S. EPA on March 22, 2007, the Permittee shall comply with the alternative compliance monitoring requirements for the vapor combustion unit.

SECTION F.3 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart Ja

Emissions Unit Description:

(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. The following specific units are considered to be affected facilities: [Section D.1]

- H-1x
- H-2
- H-3
- H-200
- H-300

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2 and H-200 is an affected facility for NOx under 40 CFR Part 60, Subpart Ja.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, H-1X, H-2, H-200, and H-300 are affected facilities for SO2 and H-200 is an affected facility for NOx under 40 CFR Part 60, Subpart Ja.

(b) Cokers. The following specific units are considered to be affected facilities: [Section D.2]

- F-201
- F-202
- F-203

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2 and NOx.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for SO2 and NOx under 40 CFR 60, Subpart Ja.

- Coker 2 delayed coking unit

Under 40 CFR Part 60, Subpart Ja, the above unit shall comply with work practice requirements for delayed coking units.

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the WRMP 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 WRMP project. Also, as part of the WRMP Project, there will be upgrades made to the atmospheric and vacuum distillation towers and various heat exchangers and associated piping. The following specific units are considered to be affected facilities: [Section D.3]

- H-101A
- H-101B
- H-102

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2 and NOx.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for NOx under 40 CFR 60, Subpart Ja.

(d) The Sulfur Recovery Plant (SRP), 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 WRMP Project, increasing the capacity to 1,300 long tons per day of sulfur. Additional sulfur capacity can be achieved with oxygen enrichment in the C, D and E Claus trains as part of the original WRMP design with no increase in permitted emissions. The following specific units are considered to be affected facilities: [Section D.4]

Under 40 CFR Part 60, Subpart Ja, the SRP is an affected facility, as that term is used in 40 CFR 60, Subparts A and Ja, for all pollutants applicable to SRPs.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities under 40 CFR 60, Subpart Ja.

(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 the UIU Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the MSAT II Compliance project approved in 2011 for construction, one (1) new C-250 Naphtha Splitter, a benzene saturation reactor system, and associated equipment (collectively identified as the Naphtha Splitter Unit) will be installed in the ISOM. The following specific units are considered to be affected facilities: [Section D.9]

- H-1

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for SO2 under 40 CFR 60, Subpart Ja.

(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 following specific units are considered to be affected facilities: [Section D.10]

- F-200A
- F-200B

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for SO2 under 40 CFR 60, Subpart Ja.

(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. The BOU is connected to the 4UF Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, the BOU heater F-401 will be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr. The following specific units are considered to be affected facilities: [Section D.11]

- F-401

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2 and NOx.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for SO2 and NOx under 40 CFR 60, Subpart Ja.

(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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. The following specific units are considered to be affected facilities: [Section D.16]

- F-1
- F-8A
- F-8B
- F-2
- F-3
- F-4
- F-5
- F-6
- F-7

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for SO2 under 40 CFR 60, Subpart Ja.

(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 following specific units are considered to be affected facilities: [Section D.17]

- B-501

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for SO2 under 40 CFR 60, Subpart Ja.

(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 following specific units are considered to be affected facilities: [Section D.18]

- B-301
- B-302

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for SO2 under 40 CFR 60, Subpart Ja.

(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 CFHU is connected to the No. 4 Ultraformer flare stack. The No. 4 Ultraformer Flare Stack, S/V 2224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.19]

- F-801A
- F-801B
- F-801C

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for SO2 under 40 CFR 60, Subpart Ja.

(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 following specific units are considered to be affected facilities: [Section D.20]

- F-101
- F-102A

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for SO2 under 40 CFR 60, Subpart Ja.

(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 following specific units are considered to be affected facilities: [Section D.21]

Under 40 CFR Part 60, Subpart Ja, the FCU-500 is an affected facility for SO2, NOx, PM, and CO.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for SO2, NOx, PM, and CO under 40 CFR 60, Subpart Ja.

(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 following specific units are considered to be affected facilities: [Section D.22]

Under 40 CFR Part 60, Subpart Ja, the FCU-600 is an affected facility for SO2, NOx, PM, and CO.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, these units are affected facilities for SO2, NOx, PM, and CO under 40 CFR 60, Subpart Ja.

(x) A portion of No. 3 Stanolind Power Station (SPS) identified as Unit ID 503. The following specific units are considered to be affected facilities: [Section D.24]

- #31 Boiler
- #32 Boiler
- #33 Boiler
- #34 Boiler
- #36 Boiler
- Duct Burner 31
- Duct Burner 32
- Duct burner 33
- Duct Burner 34
- Duct Burner 36

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for SO2 under 40 CFR 60, Subpart Ja.

(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 following specific units are considered to be affected facilities: [Section D.35]

- DDU Flare
- LPG Flare
- GOHT Flare
- South Flare

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities.

- 4UF Flare
- FCU Flare
- UIU Flare
- VRU Flare
- Alky Flare

Beginning on the dates by which the above flares are required to be tied into a flare gas recovery system, Under 40 CFR Part 60, Subpart Ja the above units are affected facilities.

(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 WRMP Project. The following specific units are considered to be affected facilities: [Section D.42]

- F-901A
- F-901B

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2 and NOx.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for SO2 and NOx under 40 CFR 60, Subpart Ja.

(oo) The New Hydrogen Unit (New HU), identified as Unit ID 801, owned and operated by Praxair, Inc. and constructed as part of the WRMP 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 NO_X. The New HU heater stacks have continuous emissions monitors (CEMs) for NO_X and CO. The following specific units are considered to be affected facilities: [Section D.43]

- New HU Heater HU-1
- New HU Heater HU-2

Under 40 CFR Part 60, Subpart Ja, the above units are affected facilities for SO2 and NOx.
Pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207, the above units are affected facilities for SO2 and NOx under 40 CFR 60, Subpart Ja.

(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)]

F.3.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1][40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as

326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Ja.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

F.3.2 Standard of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 [326 IAC 12-1][40 CFR 60, Subpart Ja]

Pursuant to 40 CFR Part 60, Subpart Ja, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart Ja, which are incorporated by reference as 326 IAC 12 (included as Attachment C.iii to this permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.100a
2. 40 CFR 60.101a
3. 40 CFR 60.102a
4. 40 CFR 60.103a
5. 40 CFR 60.104a
6. 40 CFR 60.105a
7. 40 CFR 60.106a
8. 40 CFR 60.107a
9. 40 CFR 60.108a
10. 40 CFR 60.109a
11. Table 1

SECTION F.4 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart K

Emissions Unit Description:

(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. The following specific units are considered to be affected facilities: [Section D.27]

- Tank 3534
- Tank 3601
- Tank 3605

Under 40 CFR Part 60, Subpart K, the above units are affected facilities.

(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)]

F.4.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1][40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart K.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

F.4.2 Standard 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 [326 IAC 12-1][40 CFR 60, Subpart K]

Pursuant to 40 CFR Part 60, Subpart K, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart K, which are incorporated by reference as 326 IAC 12 (included as Attachment C.iv to this permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.110 (a), (c)
2. 40 CFR 60.111
3. 40 CFR 60.112 (a)
4. 40 CFR 60.113

SECTION F.5 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart Ka

Emissions Unit Description:

(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. The following specific units are considered to be affected facilities: [Section D.27]

- Tank 3915
- Tank 3916
- Tank 3917
- Tank 3918
- Tank 3919
- Tank 3920
- Tank 3480
- Tank 3486
- Tank 3487
- Tank 3525
- Tank 3526
- Tank 3553
- Tank 3554
- Tank 3602
- Tank 3604
- Tank 3704

Under 40 CFR Part 60, Subpart Ka, the above units are affected facilities.

(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)]

F.5.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1][40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Ka.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

F.5.2 Standard of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 19, 1978 and Prior to July 23, 1984 [326 IAC 12-1][40 CFR 60, Subpart Ka]

Pursuant to 40 CFR Part 60, Subpart Ka, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart Ka, which are incorporated by reference as 326 IAC 12 (included as Attachment C.v to this permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.110a
2. 40 CFR 60.111a
3. 40 CFR 60.112a (a)(1), (a)(2)
4. 40 CFR 60.113a (a)(1)
5. 40 CFR 60.115a (a), (b), (c), (d)(1)

SECTION F.6 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart Kb

Emissions Unit Description:

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions emitted during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.7]

- Tank 2

(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. The following specific units are considered to be affected facilities: [Section D.27]

- Tank 3474
- Tank 3475
- Tank 3476
- Tank 3484
- Tank 3488
- Tank 3489
- Tank 3493
- Tank 3514
- Tank 3528
- Tank 3531
- Tank 3549
- Tank 3558
- Tank 3600
- Tank 3622
- Tank 3629
- Tank 3701
- Tank 3702
- Tank 3715
- Tank 3716
- Tank 3860
- Tank 3900
- Tank 3904
- Tank 3911
- Tank 3511
- Tank 3527
- Tank 3907

Under 40 CFR Part 60, Subpart Kb, the above units are affected facilities.

(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)]

F.6.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1][40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart Kb.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

F.6.2 Standard of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 [326 IAC 12-1][40 CFR 60, Subpart Kb]

Pursuant to 40 CFR Part 60, Subpart Kb, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart Kb, which are incorporated by reference as 326 IAC 12 (included as Attachment C.vi to this permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.110b (a), (b), (d)(2), (d)(3), (d)(4)
2. 40 CFR 60.111b
3. 40 CFR 60.112b (a)(1), (a)(2), (a)(3)
4. 40 CFR 60.113b (a), (b), (c)
5. 40 CFR 60.115b (a), (b), (c)
6. 40 CFR 60.116b (a), (b), (c), (d), (e)(1), (e)(2), (f), (g)
7. 40 CFR 60.117b

SECTION F.7 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart UU

Emissions Unit Description:

(b) Cokers. The following specific units are considered to be affected facilities: [Section D.2]

- TK - 6254

(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. The following specific units are considered to be affected facilities: [Section D.32]

- 6126
- 6127
- 3569
- 3613
- TK - 3614
- TK - 3615
- TK - 3616
- TK - 3617

Under 40 CFR Part 60, Subpart UU, the above units are affected facilities.

(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)]

F.7.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1][40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart UU.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

F.7.2 Standard of Performance for Asphalt Processing and Asphalt Roofing Manufacture [326 IAC 12-1][40 CFR 60, Subpart UU]

Pursuant to 40 CFR Part 60, Subpart UU, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart UU, which are incorporated by reference as 326 IAC 12 (included as Attachment C.Vii to this permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.470
2. 40 CFR 60.471
3. 40 CFR 60.472 (c)
4. 40 CFR 60.473 (c), (d)

5. 40 CFR 60.474 (c)(5)

SECTION F.8 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart GGG

Emissions Unit Description:

(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 following specific units are considered to be affected facilities: [Section D.17]

(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 following specific units are considered to be affected facilities: [Section D.18]

(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 CFHU is connected to the No. 4 Ultraformer flare stack. The No. 4 Ultraformer Flare Stack, S/V 2224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.19]

(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 following specific units are considered to be affected facilities: [Section D.20]

(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. The following specific units are considered to be affected facilities: [Section D.37]

Under NSPS, Subpart GGG, the compressors are considered to be affected facilities.

(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)]

F.8.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1][40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart GGG.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

F.8.2 Standard of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After Janaury 4, 1943, and on or Before November 7, 2006 [326 IAC 12-1][40 CFR 60, Subpart GGG]

Pursuant to 40 CFR Part 60, Subpart GGG, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart GGG, which are incorporated by reference as 326 IAC 12 (included as Attachment C.xi to this permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.590
2. 40 CFR 60.591
3. 40 CFR 60.592
4. 40 CFR 60.593

F.8.3 Standard of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006 [326 IAC 12-1][40 CFR 60, Subpart VV][40 CFR 60, Subpart GGG]

Pursuant to 40 CFR Part 60, Subpart GGG, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart VV, which are incorporated by reference as 326 IAC 12 (included as Attachment C.viii to this permit), as follows.

1. 40 CFR 60.480
2. 40 CFR 60.481
3. 40 CFR 60.482-1 (a), (b), (d)
4. 40 CFR 60.482-2
5. 40 CFR 60.482-3
6. 40 CFR 60.482-4
7. 40 CFR 60.482-5
8. 40 CFR 60.482-6
9. 40 CFR 60.482-7
10. 40 CFR 60.482-8
11. 40 CFR 60.482-9
12. 40 CFR 60.482-10 (a), (c), (d), (e), (f)(1), (g), (h), (j), (k), (l), (m)
13. 40 CFR 60.485 (a), (b)(1), (c), (d), (e), (f), (g),
14. 40 CFR 60.486
15. 40 CFR 60.487
16. 40 CFR 60.488
17. 40 CFR 60.489

SECTION F.9 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart GGGa

Emissions Unit Description:

(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. The following specific units are considered to be affected facilities: [Section D.1]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in volatile organic compound (VOC) service of the above process unit are considered to be affected facilities.

(b) Cokers. The following specific units are considered to be affected facilities: [Section D.2]

- Coker 2

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in volatile organic compound (VOC) service of the above process unit are considered to be affected facilities.

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the WRMP 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 WRMP project. Also, as part of the WRMP Project, there will be upgrades made to the atmospheric and vacuum distillation towers and various heat exchangers and associated piping. The following specific units are considered to be affected facilities: [Section D.3]

- K-101A
- K-101B
- K-101C

Under 40 CFR 60, Subpart GGGa, the compressor listed above is an affected facility.

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(d) The Sulfur Recovery Plant (SRP), 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 WRMP Project, increasing the capacity to 1,300 long tons per day of sulfur. Additional sulfur capacity can be achieved with oxygen enrichment in the C, D and E Claus trains as part of the original WRMP design with no increase in permitted emissions. The following specific units are considered to be affected facilities: [Section D.4]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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 instrumentation and heat exchange systems. As part of the WRMP Project, there will be upgrades made to various heat exchangers and associated piping and retraying of distillation towers at VRU 100 and VRU 200. The following specific units are considered to be affected facilities: [Section D.5]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(f) (1) 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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, there will be upgrades made to various distillation towers, compressor K-340, and associated piping at VRU 300. Upon completion of WRMP, some portions of VRU 300 will be connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.6]

- K-340

Under 40 CFR 60, Subpart GGGa, the compressor listed above is an affected facility.

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(2) Vapor Recovery Unit VRU 400 for the Coker 2, permitted in 2008, to be installed as part of the WRMP project. This unit is connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or 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 K-401), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.6]

- K-401

Under 40 CFR 60, Subpart GGGa, the compressor listed above is an affected facility.

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions emitted during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.7]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control 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 the Alky Flare or FGRS3 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 and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.8]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 the UIU Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the MSAT II Compliance project approved in 2011 for construction, one (1) new C-250 Naphtha Splitter, a benzene saturation reactor system, and associated equipment (collectively identified as the Naphtha Splitter Unit) will be installed in the ISOM. The following specific units are considered to be affected facilities: [Section D.9]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 following specific units are considered to be affected facilities: [Section D.10]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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. The BOU is connected to the 4UF Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, the BOU heater F-401 will be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr. The following specific units are considered to be affected facilities: [Section D.11]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(n) Butane, Propane and Propylene Storage and Loading Facilities, identified as Unit ID 604. The following specific units are considered to be affected facilities: [Section D.14]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 C-2 Splitter Tower will be shut down and permanently decommissioned as part of the MSAT II Compliance project, approved in 2011 for construction. The unit now consists of the C2 D-18 flare gas separator, the D-24 knock-out drum and associated piping.

The No. 3 Ultraformer is connected to the UIU flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance and reactor regenerations. The following specific units are considered to be affected facilities: [Section D.15]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. The following specific units are considered to be affected facilities: [Section D.16]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 following specific units are considered to be affected facilities: [Section D.17]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 following specific units are considered to be affected facilities: [Section D.18]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 CFHU is connected to the No. 4 Ultraformer flare stack. The No. 4 Ultraformer Flare Stack, S/V 2224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.19]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 following specific units are considered to be affected facilities: [Section D.20]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 following specific units are considered to be affected facilities: [Section D.21]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 following specific units are considered to be affected facilities: [Section D.22]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(x) A portion of No. 3 Stanolind Power Station (SPS) identified as Unit ID 503. The following specific units are considered to be affected facilities: [Section D.24]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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. The following specific units are considered to be affected facilities: [Section D.27]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(cc) The Mechanical Shop, identified as Unit 693. The following specific units are considered to be affected facilities: [Section D.29]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 following specific units are considered to be affected facilities: [Section D.30]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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. The following specific units are considered to be affected facilities: [Section D.32]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 a contemporaneous project to the WRMP Project, gasoline loading at the Marine dock will cease. The following specific units are considered to be affected facilities: [Section D.34]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 following specific units are considered to be affected facilities: [Section D.35]

- 4UF Flare
- FCU Flare
- UIU Flare
- VRU Flare
- Alky Flare
- DDU Flare
- LPG Flare
- GOHT Flare
- South Flare

Under 40 CFR 60, Subpart GGGa, the flares are subject to the control devise standards as specified in 40 CFR 60, Subpart GGGa

- K-103A
- K-103B

- K-281
- K-282
- K-283
- K-284
- K-291
- K-292
- K-293
- K-946A
- K-946B

Under 40 CFR 60, Subpart GGGa, the above compressors associated with the flare gas recovery units are affected facilities.

(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 and heat exchange systems. This facility also contains area drains and an oil/water separator. The following specific units are considered to be affected facilities: [Section D.36]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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. The following specific units are considered to be affected facilities: [Section D.37]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(mm) 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 a wet scrubber/carbon canister system (identified as S-1). The facility is approved for construction in 2007, is operated as a batch process. The following specific units are considered to be affected facilities: [Section D.41]

Under 40 CFR 60, Subpart GGGa, each pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities.

(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 WRMP Project. The following specific units are considered to be affected facilities: [Section D.42]

- K-901A
- K-901B
- K-901C
- K-902

Under 40 CFR 60, Subpart GGGa, each pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities. Under ~~NSPS~~40 CFR 60 GGGa, the compressors listed above are affected facilities.

(oo) The New Hydrogen Unit (New HU), identified as Unit ID 801, owned and operated by Praxair, Inc. and constructed as part of the WRMP 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 NO_X. The New HU heater stacks have continuous emissions monitors (CEMs) for NO_X and CO. The following specific units are considered to be affected facilities: [Section D.43]

- C-9210
- C-9230

Under 40 CFR 60, Subpart GGGa, each pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flange or other connector in VOC service of the above process unit are considered to be affected facilities. Under 40 CFR 60 GGGa, the compressors listed above are affected facilities.

- HU Flare

Under 40 CFR 60, Subpart GGGa, the flare is subject to the control devise standards as specified in 40 CFR 60, Subpart GGGa

(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)]

F.9.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1][40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart GGGa.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

F.9.2 Standard of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After November 7, 2006 [326 IAC 12-1][40 CFR 60, Subpart GGGa]

Pursuant to 40 CFR Part 60, Subpart GGGa, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart GGGa, which are incorporated by reference as 326 IAC 12 (included as Attachment C.xii to this permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.590a
2. 40 CFR 60.591a

3. 40 CFR 60.592a
4. 40 CFR 60.593a

F.9.3 Standard 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 [326 IAC 12-1][40 CFR 60, Subpart VVa][40 CFR 60, Subpart GGGa

Pursuant to 40 CFR Part 60, Subpart GGGa, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart VVa, which are incorporated by reference as 326 IAC 12 (included as Attachment C.ix to this permit), as follows.

1. 40 CFR 60.481a
2. 40 CFR 60.482-1a
3. 40 CFR 60.482-2a
4. 40 CFR 60.482-3a
5. 40 CFR 60.482-4a
6. 40 CFR 60.482-5a
7. 40 CFR 60.482-6a
8. 40 CFR 60.482-7a
9. 40 CFR 60.482-8a
10. 40 CFR 60.482-9a
11. 40 CFR 60.482-10a
12. 40 CFR 60.483-1a
13. 40 CFR 60.483-2a
14. 40 CFR 60.484a
15. 40 CFR 60.485a
16. 40 CFR 60.486a
17. 40 CFR 60.487a

SECTION F.10 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart NNN

Emissions Unit Description:

(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. The following specific units are considered to be affected facilities: [Section D.1]

- T-2 Primary Tower
- T-3C Primary Gas Oil stripper
- T-3B Light Middle Distillate Stripper
- T-3A Heavy Naphtha Stripper
- T-4 First Vacuum Tower
- T-5 Second Vacuum Tower
- T-200 crude Tower
- T-201D PGO Stripper
- T-201C HMD Stripper
- T-201B LMD Stripper
- T-201A HVN Stripper
- T-300 Vacuum Tower

(b) Cokers. The following specific units are considered to be affected facilities: [Section D.2]

- T-201 Coker 2 Fractionator
- D-202 Kerosene Stripper

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the WRMP 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 WRMP project. Also, as part of the WRMP Project, there will be upgrades made to the atmospheric and vacuum distillation towers and various heat exchangers and associated piping. The following specific units are considered to be affected facilities: [Section D.3]

- T-101 Primary Fractionator
- T-4 Primary Gasoil Stripper
- T-103B Middle Distillate Stripper
- T-103C Middle Distillate Stripper
- T-102 Vacuum Tower

(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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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 instrumentation and heat exchange systems. As part of the WRMP Project, there will be upgrades made to various heat exchangers and associated piping and retraying of distillation towers at VRU 100 and VRU 200. The following specific units are considered to be affected facilities: [Section D.5]

- E-101A Absorber

- E-104 Sponge Oil Absorber
- E-102 Lean Oil Still
- E-103 Depropanizer
- E-105A Depropanizer
- E-106 Dethanizer
- E-201A Absorber
- E-204 Sponge Oil Absorber
- E-202 Lean Oil Still
- E-203 Depropanizer
- E-205 Depropanizer

(f) (1) 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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, there will be upgrades made to various distillation towers, compressor K-340, and associated piping at VRU 300. Upon completion of WRMP, some portions of VRU 300 will be connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.6]

- T-303 Debutanizer
- T-301 Depropanizer
- T-391 Sat Extractor
- T-302 Debutanizer
- T-352 Dehaxanizer
- T-370 Debutanizer
- T-390 BB Extraction Tower
- T-380 Catalytic RAN Debutanizer
- T-351A Sponge Oil Absorber
- T-351B Primary Absorber
- T-351C Stripper
- T-340A Absorber
- T-340 Absorber
- T-304 deethanizer

(2) Vapor Recovery Unit VRU 400 for the Coker 2, permitted in 2008, to be installed as part of the WRMP project. This unit is connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or 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 K-401), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.6]

- T-401 Absorber
- T-403 Sponge Adsorber
- T-405 Coker Producit Gas Amine Scrubber
- T-404 Debutanizer
- T-406 C3/C4 Amine Contactor
- T-407 Splitter
- T-408 Naphtha Splitter

- T-441 Extractor Plus
- T-442 Oxidizer

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions emitted during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.7]

- T-1 Deisoobutanizer
- T-2 Debutanizer
- T-6 C4/C5 plitter
- T-5 Debutanizer
- D-71 R-1 Vapor Cyclone Separator
- D-72 R-2 Vapor Cyclone Separator
- D-73 R-3 Vapor Cyclone Separator
- D-74 R-4 Vapor Cyclone Separator
- D-77 R-5 Vapor Cyclone Separator
- T-3 Depropanizer
- T-4 Depropanizer

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control 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 the Alky Flare or FGRS3 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 and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.8]

- T-114 deethanizer
- T-101 Propylene Splitter

(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 the UIU Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the MSAT II Compliance project approved in 2011 for construction, one (1) new C-250 Naphtha Splitter, a benzene saturation reactor system, and associated equipment (collectively identified as the Naphtha Splitter Unit) will be installed in the ISOM. The following specific units are considered to be affected facilities: [Section D.9]

- C-250 Naphtha Splitter
- C-2 Stripper
- D-49 Reactor Effluent Separator
- D-50 High Pressure Separator
- D-56/57/58/59 Adsorbers
- C-1 Stabilizer
- C-3 Stabilizer

(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 following specific units are considered to be affected facilities: [Section D.10]

- C-300 Ultraformer Splitter
- C-301 Xylene Fractionator
- C-200 SHN Splitter
- C-201 SHN Heartcut Tower

(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. The BOU is connected to the 4UF Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, the BOU heater F-401 will be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr. The following specific units are considered to be affected facilities: [Section D.11]

- C-401 Feed Stripper
- D-402 HP Separator
- D-403 Low Pressure Separator
- C-402 Product Stripper

(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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. The following specific units are considered to be affected facilities: [Section D.16]

- C-6 Naphtha Splitter
- C-1A Feed Absorber / C-1B Pre-Absorber
- C-5 Light Ends Stripper
- C-3 Debutanizer
- C-4 Depropanizer
- C-7 Rerun Tower

(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 CFHU is connected to the No. 4 Ultraformer flare stack. The No. 4 Ultraformer Flare Stack, S/V 2224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.19]

- C-801A Product Stripper
- J-805 High Pressure Separator

(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 following specific units are considered to be affected facilities: [Section D.20]

- C-101 Absorber
- C-103 Stripper

(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 following specific units are considered to be affected facilities: [Section D.21]

- E-1A Fractionator
- E-2 LCCO Stripper

(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 following specific units are considered to be affected facilities: [Section D.22]

- E-1 fractionator
- E-2 LCCO Stripper

(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 WRMP Project. The following specific units are considered to be affected facilities: [Section D.42]

- D-903 Hot HP Separator Drum
- D-905 Cold HP Separator Drum
- C-902 HP Amine Absorber
- D-904 Hot MP Separator Drum
- D-916 Cold MP Separator Drum
- C-906 MP Amine Absorber Drum
- C-901 Stripper
- C-903 LP Amine Absorber Scrubber

Under 40 CFR Part 60, Subpart NNN, the above units are affected facilities.

(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)]

F.10.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1][40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart NNN.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

F.10.2 Standard of Performance for VOC Emissions from Synthetic Oganic Chemical Manufacturing (SOCMI) Distillation Operations [326 IAC 12-1][40 CFR 60, Subpart NNN][326 IAC 8-18]

Pursuant to 40 CFR Part 60, Subpart NNN, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart NNN, which are incorporated by reference as 326 IAC 12 (included as Attachment C.xiii to this permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.660 (a), (b)(1), (c)(1), (d)
2. 40 CFR 60.661
3. 40 CFR 60.666
4. 40 CFR 60.667

For the applicable units, compliance with the requirements of 40 CFR 60, Subpart NNN shall constitute compliance with 326 IAC 8-18.

SECTION F.11 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart QQQ

Emissions Unit Description:

(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. The following specific units are considered to be affected facilities: [Section D.1]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(b) Cokers. The following specific units are considered to be affected facilities: [Section D.2]

- 11B Coker
- Coker 2

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the WRMP 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 WRMP project. Also, as part of the WRMP Project, there will be upgrades made to the atmospheric and vacuum distillation towers and various heat exchangers and associated piping. The following specific units are considered to be affected facilities: [Section D.3]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(d) The Sulfur Recovery Plant (SRP), 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 WRMP Project, increasing the capacity to 1,300 long tons per day of sulfur. Additional sulfur capacity can be achieved with oxygen enrichment in the C, D and E Claus trains as part of the original WRMP design with no increase in permitted emissions. The following specific units are considered to be affected facilities: [Section D.4]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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 instrumentation and heat exchange systems. As part of the WRMP Project, there will be upgrades made to various heat exchangers and associated piping and retraying of distillation towers at VRU 100 and VRU 200. The following specific units are considered to be affected facilities: [Section D.5]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(f) (1) 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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, there will be upgrades made to various distillation towers, compressor K-340, and associated piping at VRU 300. Upon completion of WRMP, some portions of VRU 300 will be connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.6]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(2) Vapor Recovery Unit VRU 400 for the Coker 2, permitted in 2008, to be installed as part of the WRMP project. This unit is connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or 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 K-401), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.6]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions emitted during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.7]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control 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 the Alky Flare or FGRS3 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 and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.8]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 the UIU Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the MSAT II

Compliance project approved in 2011 for construction, one (1) new C-250 Naphtha Splitter, a benzene saturation reactor system, and associated equipment (collectively identified as the Naphtha Splitter Unit) will be installed in the ISOM. The following specific units are considered to be affected facilities: [Section D.9]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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. The BOU is connected to the 4UF Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, the BOU heater F-401 will be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr. The following specific units are considered to be affected facilities: [Section D.11]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 C-2 Splitter Tower will be shut down and permanently decommissioned as part of the MSAT II Compliance project, approved in 2011 for construction. The unit now consists of the C2 D-18 flare gas separator, the D-24 knock-out drum and associated piping.

The No. 3 Ultraformer is connected to the UIU flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance and reactor regenerations. The following specific units are considered to be affected facilities: [Section D.15]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. The following specific units are considered to be affected facilities: [Section D.16]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 following specific units are considered to be affected facilities: [Section D.17]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 following specific units are considered to be affected facilities: [Section D.18]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 CFHU is connected to the No. 4 Ultraformer flare stack. The No. 4 Ultraformer Flare Stack, S/V 2224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.19]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 ^oF 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 following specific units are considered to be affected facilities: [Section D.21]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 ^oF 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 following specific units are considered to be affected facilities: [Section D.22]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(x) A portion of No. 3 Stanolind Power Station (SPS) identified as Unit ID 503. The following specific units are considered to be affected facilities: [Section D.24]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(y) Hazardous Waste Treatment System. The following specific units are considered to be affected facilities: [Section D.25]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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. As part of the Lakefront Upgrades (LFU) Project, approved in 2014 for modification, the larger solids in the wastewater will be removed in the new Solids Collection System. Then the wastewater will be routed to tanks TK-5050, TK-5051 and TK-5052, which will operate in parallel and serve as oil-water separators, equalization, and stormwater surge. Floating oil will be separated and skimmed from the tanks and recycled. The water will be routed to the new Dissolved Nitrogen Floatation (DNF) Units to remove suspended solids and oil, which will be 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 final filters before being returned to Lake Michigan. The following specific units are considered to be affected facilities: [Section D.26]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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. The following specific units are considered to be affected facilities: [Section D.27]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(ee) Cooling Towers. The following specific units are considered to be affected facilities: [Section D.31]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 a contemporaneous project to the WRMP Project, gasoline loading at the Marine dock will cease. The following specific units are considered to be affected facilities: [Section D.34]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 following specific units are considered to be affected facilities: [Section D.35]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 and heat exchange systems. This facility also contains area drains and an oil/water separator. The following specific units are considered to be affected facilities: [Section D.36]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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. The following specific units are considered to be affected facilities: [Section D.37]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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 WRMP Project. The following specific units are considered to be affected facilities: [Section D.42]

Under 40 CFR 60, Subpart QQQ, the individual drain systems, oil-water separators, and closed vent systems and control devices of the above processes are considered to be affected facilities.

(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)]

F.11.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1][40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart QQQ.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

F.11.2 Standard of Performance for VOC Emissions for Petroelum Refinery Wastewater Systems [326 IAC 12-1][40 CFR 60, Subpart QQQ]

Pursuant to 40 CFR Part 60, Subpart QQQ, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart QQQ, which are incorporated by reference as 326 IAC 12 (included as Attachment C.xiv to this permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.690
2. 40 CFR 60.691
3. 40 CFR 60.692-1
4. 40 CFR 60.692-2
5. 40 CFR 60.692-3
6. 40 CFR 60.692-4
7. 40 CFR 60.692-5 (b), (d), (e)
8. 40 CFR 60.692-6
9. 40 CFR 60.692-7
10. 40 CFR 60.693-2
11. 40 CFR 60.695 (a)(3)(ii)
12. 40 CFR 60.696 (a), (b), (d)
13. 40 CFR 60.697 (a), (b), (c), (d), (e), (f)(1), (f)(2), (f)(3)(i - vii), (f)(3)(x)(B), (g), (h), (i), (j), (k)
14. 40 CFR 60.698 (a), (b), (c), (d)(3)(ii), (e)
15. 40 CFR 60.699

F.11.3 Standards of Performance for VOC Emissions for Petroelum Refinery Wastewater Systems Modification Requirments [326 IAC 12-1][40 CFR 60, Subpart QQQ]

Prior to the completion of any modification to a potentially affected facility per 40 CFR 60, Subpart QQQ, the Permittee shall make a determination as to whether 40 CFR 60, Subpart QQQ has been triggered. If the Permittee determines that Subpart QQQ has been triggered, the Permittee shall comply with the requirements of that rule for individual drain systems, oil water separators, and closed vent systems and control devices upon implementation of the changes.

SECTION F.12 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart RRR

Emissions Unit Description:

(f) (2) Vapor Recovery Unit VRU 400 for the Coker 2, permitted in 2008, to be installed as part of the WRMP project. This unit is connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or 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 K-401), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.6]

- R-431 Di-Olefin reactor
- R-432A Silica Reactor
- R-432B Silica Reactor
- T-442 Oxidizer

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions emitted during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.7]

- R-1 Reactor
- R-2 Reactor
- R-3 Reactor
- R-4 Reactor
- R-5 Reactor

(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 the UIU Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the MSAT II Compliance project approved in 2011 for construction, one (1) new C-250 Naphtha Splitter, a benzene saturation reactor system, and associated equipment (collectively identified as the Naphtha Splitter Unit) will be installed in the ISOM. The following specific units are considered to be affected facilities: [Section D.9]

- D-1 & D-2 Hydrogen Treating Reactors
- D-3 Isomerization Reactor
- D-4 Isomerization Reactor
- D-5 Isomerization Reactor
- D-6 Isomerization Reactor
- D-8 Isomerization Reactor

(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. The BOU is connected to the 4UF Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, the BOU heater F-401 will be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr. The following specific units are considered to be affected facilities: [Section D.11]

- D-401 Ultrafiner Reactor

(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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. The following specific units are considered to be affected facilities: [Section D.16]

- D-1 Ultrafiner Reactor
- D-3 Reactor
- D-4 Reactor
- D-5 Reactor
- D-6 Reactor
- D-7 Reactor
- D-8 Swing Reactor

(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 CFHU is connected to the No. 4 Ultraformer flare stack. The No. 4 Ultraformer Flare Stack, S/V 2224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.19]

- D-801A Cat Feed Unit Reactor
- D-802A Cat Feed Unit Reactor
- D-801B Cat Feed Unit Reactor
- D-802B Cat Feed Unit Reactor

(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 following specific units are considered to be affected facilities: [Section D.20]

- D-103 Reactor
- D-104 Reactor
- D-105 Reactor
- D-114 Reactor

(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 following specific units are considered to be affected facilities: [Section D.21]

- D-1 Disengager (Reactor)
- D-3 Disengager (Reactor) Stripper

(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 following specific units are considered to be affected facilities: [Section D.22]

- D-1 Reactor
- D-3 Reactor Stripper

(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 WRMP Project. The following specific units are considered to be affected facilities: [Section D.42]

- D-901A Guard Reactor A
- D-902A DHT Reactor A
- D-901B Guard Reactor B
- D-902B DHT Reactor B

Under 40 CFR Part 60, Subpart RRR, the above units are affected facilities.

(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)]

F.12.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1][40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart RRR.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

F.12.2 Standard of Performance for VOC Emissions from Synthetic Organic Chemical Manufacturing (SOCMI) Reactor Processes [326 IAC 12-1][40 CFR 60, Subpart RRR][326 IAC 8-18]

Pursuant to 40 CFR Part 60, Subpart RRR, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart RRR, which are incorporated by reference as 326 IAC 12 (included as Attachment C.xv to this permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.700 (a), (b)(1), (c)(5), (c)(6), (d)
2. 40 CFR 60.701
3. 40 CFR 60.706
4. 40 CFR 60.707

For the applicable units, compliance with the requirements of 40 CFR 60, Subpart RRR shall constitute compliance with 326 IAC 8-18.

SECTION F.13 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart IIII

Emissions Unit Description:

(oo) The New Hydrogen Unit (New HU), identified as Unit ID 801, owned and operated by Praxair, Inc. and constructed as part of the WRMP 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 NO_X. The New HU heater stacks have continuous emissions monitors (CEMs) for NO_X and CO. The following specific units are considered to be affected facilities: [Section D.43]

- One (1) diesel-fueled emergency generator rated at 1,214 HP.

Insignificant Activities

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

(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 not related to the WRMP project. [Section A]

(y) Other activities associated with emergencies, including on-site fire training approved by the department and stationary fire pump engines not related to the WRMP project. [Section A]

(ee) Three (3) emergency diesel-fired fire pump engines, identified as Firepump 1, 2 and 3, per SPM 089-25488-00453, one rated at 359 HP and two rated at 460 HP. [Section D.45]

Under 40 CFR Part 60, Subpart IIII, the above units are affected facilities.

(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)]

F.13.1 General Provision Relating to New Source Performance Standards [326 IAC 12-1][40 CFR 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart IIII.

(b) Pursuant to 40 CFR 60.4, the Permittee shall submit all required notifications and reports to:

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

F.13.2 Standard of Performance for Compression Ignition Internal Combustion Engines [326 IAC 12-1][40 CFR 60, Subpart IIII]

Pursuant to 40 CFR Part 60, Subpart IIII, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart IIII, which are incorporated by reference as 326 IAC 12 (included as Attachment C.xvi to this permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.4200
2. 40 CFR 60.4204
3. 40 CFR 60.4205
4. 40 CFR 60.4206
5. 40 CFR 60.4207
6. 40 CFR 60.4208
7. 40 CFR 60.4209
8. 40 CFR 60.4211
9. 40 CFR 60.4212
10. 40 CFR 60.4213
11. 40 CFR 60.4214
12. 40 CFR 60.4217
13. 40 CFR 60.4218
14. 40 CFR 60.4219
15. Table 1
16. Table 2
17. Table 3
18. Table 4
19. Table 5
20. Table 6
21. Table 7
22. Table 8

SECTION G.1 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 61, Subpart J

Emissions Unit Description:

(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 following specific units are considered to be affected facilities: [Section D.10]

Under 40 CFR 61, Subpart J, the provisions of 40 CFR 61, Subpart J apply to the pumps, pressure relief devices, sampling connection systems, open-ended valves, open-ended lines, and valves at each of the above sources when intended to operate in benzene service are considered to be affected facilities.

(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. The following specific units are considered to be affected facilities: [Section D.27]

Under 40 CFR 61, Subpart J, the provisions of 40 CFR 61, Subpart J apply to the pumps, pressure relief devices, sampling connection systems, open-ended valves, open-ended lines, and valves at each of the above sources when intended to operate in benzene service are considered to be affected facilities.

(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 following specific units are considered to be affected facilities: [Section D.35]

- 4FU Flare
- FCU Flare
- UIU Flare
- VRU Flare
- Alky Flare

Under 40 CFR 61, Subpart J, the above flares shall be subject to the control devise standards specified in 40 CFR 61, Subpart J when controlling sources listed above that intended to operate in benzene service considered to be affected facilities.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

National Emissions Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

G.1.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants under 40 CFR Part 61 [326 IAC 14-1][40 CFR Part 61, Subpart A]

(a) Pursuant to 40 CFR 61.01, the Permittee shall comply with the applicable provisions of 40 CFR Part 61, Subpart A – General Provisions, which are incorporated by reference as

326 IAC 14-1, for the emission unit(s) listed above, as specified in 40 CFR Part 61, Subpart J, in accordance with the schedule in 40 CFR 61, Subpart J.

(b) Pursuant to 40 CFR 61.04, the Permittee shall submit all required notifications and reports to:

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

G.1.2 National Emissions Standards for Hazardous Air Pollutants for Equipment Leaks (Fugitive Emission Sources) of Benzene [40 CFR Part 61, Subpart J][326 IAC 14-7]

Pursuant to 40 CFR Part 61, Subpart J, the Permittee shall comply with the applicable provisions of 40 CFR Part 61, Subpart J, which are incorporated by reference as 326 IAC 14-7 (included as Attachment D.i to this permit), for the emission unit(s) listed above, as specified as follows.

1. 40 CFR 61.110 (a), (c), (d)
2. 40 CFR 61.111
3. 40 CFR 61.112 (a)

SECTION G.2 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 61, Subpart V

Emissions Unit Description:

(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 following specific units are considered to be affected facilities: [Section D.10]

Under 40 CFR 61, Subpart V, each pumps, pressure relief devices, sampling connection systems, open-ended valves, open-ended lines, and valves of the below units shall comply with 40 CFR 61, Subpart V when operating in benzene service are considered to be affected facilities.

(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. The following specific units are considered to be affected facilities: [Section D.27]

Under 40 CFR 61, Subpart V, each pumps, pressure relief devices, sampling connection systems, open-ended valves, open-ended lines, and valves of the below units shall comply with 40 CFR 61, Subpart V when operating in benzene service are considered to be affected facilities.

(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 following specific units are considered to be affected facilities: [Section D.35]

- 4FU Flare
- FCU Flare
- UIU Flare
- VRU Flare
- Alky Flare

Under 40 CFR 61, Subpart V, the above flares shall comply with the requirements specified in 40 CFR 61, Subpart V for control device standards as that term is use in 40 CFR 61, Subpart V when controlling sources listed above are operating in benzene service as defined in 40 CFR 61, Subpart V.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

National Emissions Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

G.2.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants under 40 CFR Part 61 [326 IAC 14-1][40 CFR Part 61, Subpart A]

(a) Pursuant to 40 CFR 61.01, the Permittee shall comply with the applicable provisions of 40 CFR Part 61, Subpart A – General Provisions, which are incorporated by reference as

326 IAC 14-1, for the emission unit(s) listed above, as specified in 40 CFR Part 61, Subpart J, in accordance with the schedule in 40 CFR 61, Subpart V.

(b) Pursuant to 40 CFR 61.04, the Permittee shall submit all required notifications and reports to:

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

G.2.2 National Emissions Standards for Hazardous Air Pollutants for Equipment Leaks (Fugitive Emission Sources) [40 CFR Part 61, Subpart V][326 IAC 14-8]

Pursuant to 40 CFR Part 61, Subpart V, the Permittee shall comply with the applicable provisions of 40 CFR Part 61, Subpart V, which are incorporated by reference as 326 IAC 14-8 (included as Attachment D.ii to this permit), for the emission unit(s) listed above, as specified as follows.

1. 40 CFR 61.240
2. 40 CFR 61.241
2. 40 CFR 61.242-1
3. 40 CFR 61.242-11 (a), (c), (d), (e), (f)(1), (g), (h), (i), (k), (l), (m)
4. 40 CFR 61.245 (a), (b), (e)
5. 40 CFR 61.246 (a), (d), (e)(1)
6. 40 CFR 61.247 (a), (b), (c), (e)

SECTION G.3 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 61, Subpart FF

Emissions Unit Description:

(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. The following specific units are considered to be affected facilities: [Section D.1]

- Tank 3030

Under 40 CFR 61, Subpart FF, the tanks, closed vent systems and control devices that are used for benzene waste operations for the tank listed above shall comply with the requirements of 40 CFR 61, Subpart FF.

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(b) Cokers. The following specific units are considered to be affected facilities: [Section D.2]

- 11B Coker
- Coker 2

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the WRMP 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 WRMP project. Also, as part of the WRMP Project, there will be upgrades made to the atmospheric and vacuum distillation towers and various heat exchangers and associated piping. The following specific units are considered to be affected facilities: [Section D.3]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(d) The Sulfur Recovery Plant (SRP), 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 WRMP Project, increasing the capacity to 1,300 long tons per day of sulfur. Additional sulfur capacity can be achieved with oxygen enrichment in the C, D and E Claus trains as part of the original WRMP design with no increase in permitted emissions. The following specific units are considered to be affected facilities: [Section D.4]

- TK - 431
- TK-410

Under 40 CFR 61, Subpart FF, the tanks, closed vent systems and control devices that are used for benzene waste operations for the tank listed above shall comply with the requirements of 40 CFR 61, Subpart FF.

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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 instrumentation and heat exchange systems. As part of the WRMP Project, there will be upgrades made to various heat exchangers and associated piping and retraying of distillation towers at VRU 100 and VRU 200. The following specific units are considered to be affected facilities: [Section D.5]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(f) (1) 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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, there will be upgrades made to various distillation towers, compressor K-340, and associated piping at VRU 300. Upon completion of WRMP, some portions of VRU 300 will be connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.6]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(2) Vapor Recovery Unit VRU 400 for the Coker 2, permitted in 2008, to be installed as part of the WRMP project. This unit is connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or 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 K-401), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.6]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions emitted during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.7]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control 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 the Alky Flare or FGRS3 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 and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.8]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 the UIU Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the MSAT II Compliance project approved in 2011 for construction, one (1) new C-250 Naphtha Splitter, a benzene saturation reactor system, and associated equipment (collectively identified as the Naphtha Splitter Unit) will be installed in the ISOM. The following specific units are considered to be affected facilities: [Section D.9]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 following specific units are considered to be affected facilities: [Section D.10]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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. The BOU is connected to the 4UF Flare and associated flare gas recovery system FGRS4 (identified in Section D.35).

This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, the BOU heater F-401 will be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr. The following specific units are considered to be affected facilities: [Section D.11]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 C-2 Splitter Tower will be shut down and permanently decommissioned as part of the MSAT II Compliance project, approved in 2011 for construction. The unit now consists of the C2 D-18 flare gas separator, the D-24 knock-out drum and associated piping.

The No. 3 Ultraformer is connected to the UIU flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance and reactor regenerations. The following specific units are considered to be affected facilities: [Section D.15]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. The following specific units are considered to be affected facilities: [Section D.16]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 following specific units are considered to be affected facilities: [Section D.17]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 following specific units are considered to be affected facilities: [Section D.18]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 CFHU is connected to the No. 4 Ultraformer flare stack. The No. 4 Ultraformer Flare Stack, S/V 2224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.19]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 following specific units are considered to be affected facilities: [Section D.20]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 following specific units are considered to be affected facilities: [Section D.21]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 following specific units are considered to be affected facilities: [Section D.22]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(x) A portion of No. 3 Stanolind Power Station (SPS) identified as Unit ID 503. The following specific units are considered to be affected facilities: [Section D.24]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(y) Hazardous Waste Treatment System. The following specific units are considered to be affected facilities: [Section D.25]

Under 40 CFR 61, Subpart FF, the wastewater tanks and waste streams associated with the dewatering systems, individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations are subject to 40 CFR 61, Subpart FF.

(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. As part of the Lakefront Upgrades (LFU) Project, approved in 2014 for modification, the larger solids in the wastewater will be removed in the new Solids Collection System. Then the wastewater will be routed to tanks TK-5050, TK-5051 and TK-5052, which will operate in parallel and serve as oil-water separators, equalization, and stormwater surge. Floating oil will be separated and skimmed from the tanks and recycled. The water will be routed to the new Dissolved Nitrogen Floatation (DNF) Units to remove suspended solids and oil, which will be 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 final filters before being returned to Lake Michigan. The following specific units are considered to be affected facilities: [Section D.26]

- Dissolved Nitrogen Floatation (DNF) System
- TK-5050
- TK-5051
- TK-5052
- TK-303
- TK-304
- TK-562
- Solids Collection System

Under 40 CFR 61, Subpart FF, the tanks, closed vent systems and control devices that are used for benzene waste operations for the tanks listed above shall comply with the requirements of 40 CFR 61, Subpart FF.

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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. The following specific units are considered to be affected facilities: [Section D.27]

- TK-3559
- TK-3560

Under 40 CFR 61, Subpart FF, the tanks, closed vent systems and control devices that are used for benzene waste operations for the tanks listed above shall comply with the requirements of 40 CFR 61, Subpart FF.

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(bb) The general facility remediation system, identified as Unit 999. Remediation includes multiple well point systems. The well point systems extract groundwater which may have a small hydrocarbon fraction. 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. The following specific units are considered to be affected facilities: [Section D.28]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(ee) Cooling Towers. The following specific units are considered to be affected facilities: [Section D.31]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 a contemporaneous project to the WRMP Project, gasoline loading at the Marine dock will cease. The following specific units are considered to be affected facilities: [Section D.34]

- BT-1
- BT-2

Under 40 CFR 61, Subpart FF, the tanks, closed vent systems and control devices that are used for benzene waste operations for the tanks listed above shall comply with the requirements of 40 CFR 61, Subpart FF.

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 following specific units are considered to be affected facilities: [Section D.35]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 and heat exchange systems. This facility also contains area drains and an oil/water separator. The following specific units are considered to be affected facilities: [Section D.36]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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. The following specific units are considered to be affected facilities: [Section D.37]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(mm) 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 a wet scrubber/carbon canister system (identified as S-1). The facility is approved for construction in 2007, is operated as a batch process. The following specific units are considered to be affected facilities: [Section D.41]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(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 WRMP Project. The following specific units are considered to be affected facilities: [Section D.42]

Under 40 CFR 61, Subpart FF, the individual drain systems, oil water separators, and closed vent systems and control devices that are used for benzene waste operations of the above processes shall comply with the requirements of 40 CFR 61, Subpart FF.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

National Emissions Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

G.3.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants under 40 CFR Part 61 [326 IAC 14-1][40 CFR Part 61, Subpart A]

(a) Pursuant to 40 CFR 61.01, the Permittee shall comply with the applicable provisions of 40 CFR Part 61, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 14-1, for the emission unit(s) listed above, as specified in 40 CFR Part 61, Subpart J, in accordance with the schedule in 40 CFR 61, Subpart FF.

(b) Pursuant to 40 CFR 61.04, the Permittee shall submit all required notifications and reports to:

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

G.3.2 National Emissions Standards for Hazardous Air Pollutants for Benzene Waste Operations [40 CFR Part 61, Subpart FF]

Pursuant to 40 CFR Part 61, Subpart FF, the Permittee shall comply with the applicable provisions of 40 CFR Part 61, Subpart FF, (included as Attachment D.iii to this permit), for the emission unit(s) listed above, as specified as follows.

1. 40 CFR 61.340
2. 40 CFR 61.341
3. 40 CFR 61.342
4. 40 CFR 61.343
5. 40 CFR 61.345
6. 40 CFR 61.346
7. 40 CFR 61.347
8. 40 CFR 61.348 (a)(1)(i), (a)(2), (a)(3), (a)(4), (a)(5), (c), (e), (f), (g)
9. 40 CFR 61.349 (a), (b), (c), (d), (e), (f), (g), (h)
10. 40 CFR 61.350
11. 40 CFR 61.351
12. 40 CFR 61.352 (a)(1), (b), (c)
13. 40 CFR 61.354 (a), (c), (d), (e), (f), (g)
14. 40 CFR 61.355 (a)(1), (a)(2), (a)(3), (a)(6), (b)(1), (b)(3), (b)(5), (b)(6), (b)(7), (c), (d), (e), (h), (i), (j), (k)
15. 40 CFR 61.356 (a), (b)(1), (b)(4), (b)(5), (c), (d), (e), (f), (g), (h), (i), (j), (k), (l), (m)
16. 40 CFR 61.357 (a), (d), (e), (f), (g)
17. Appendix A
18. Appendix B
19. Appendix C
20. Appendix D
21. Appendix E

SECTION H.1 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 63, Subpart Y

Emissions Unit Description:

(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 a contemporaneous project to the WRMP Project, gasoline loading at the Marine dock will cease. The following specific units are considered to be affected facilities: [Section D.34]

Under NESHAP, Subpart Y, the above processes are considered to be affected facilities.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

National Emissions Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

H.1.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.642, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1, for the emission unit(s) listed above, as specified in 40 CFR Part 63, Subpart Y, in accordance with the schedule in 40 CFR Part 63, Subpart Y.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

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

H.1.2 National Emissions Standards for Hazardous Air Pollutants for Marine Tank Vessel Loading Operations [40 CFR Part 63, Subpart Y][326 IAC 20-17][40 CFR 63, Subpart CC]

Pursuant to 40 CFR Part 63, Subpart Y and 40 CFR Part 63, Subpart CC, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart Y, which are incorporated by reference as 326 IAC 20-17 (included as Attachment E.ii to this permit), as follows.

1. 40 CFR 63.560
2. 40 CFR 63.561
3. 40 CFR 63.562
4. 40 CFR 63.563
5. 40 CFR 63.564
6. 40 CFR 63.565
7. 40 CFR 63.566
8. 40 CFR 63.567
9. 40 CFR 63.568

SECTION H.2 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 63, Subpart CC

Emissions Unit Description:

(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. The following specific units are considered to be affected facilities: [Section D.1]

- Tank 3030
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices. Tank 3030 shall be operated in accordance to the applicable wastewater requirements in 40 CFR 63, Subpart CC.
- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,

(b) Cokers. The following specific units are considered to be affected facilities: [Section D.2]

- 11B Coker
    - All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.
    -
- Coker 2
    - All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
    - The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
    - All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.

  The following are Group 2 storage vessels:
    - Tank 6254

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the WRMP 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 WRMP project. Also, as part of the WRMP Project, there will be upgrades made to the atmospheric and vacuum distillation towers and various heat exchangers and associated piping. The following specific units are considered to be affected facilities: [Section D.3]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. The Group 1 miscellaneous process vent emissions from No. 12

Pipe Still are routed to the South Flare and associated flare gas recovery system FGRS1.

(d) The Sulfur Recovery Plant (SRP), 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 WRMP Project, increasing the capacity to 1,300 long tons per day of sulfur. Additional sulfur capacity can be achieved with oxygen enrichment in the C, D and E Claus trains as part of the original WRMP design with no increase in permitted emissions. The following specific units are considered to be affected facilities: [Section D.4]

- Tank 410
- Tank 431
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices. Tanks 410 and 431 shall be operated in accordance to the applicable wastewater requirements in 40 CFR 63, Subpart CC.

(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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or 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 instrumentation and heat exchange systems. As part of the WRMP Project, there will be upgrades made to various heat exchangers and associated piping and retraying of distillation towers at VRU 100 and VRU 200. The following specific units are considered to be affected facilities: [Section D.5]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.

(f) (1) 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 the VRU Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, there will be upgrades made to various distillation towers, compressor K-340, and associated piping at VRU 300. Upon completion of WRMP, some portions of VRU 300 will be connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.6]

  - All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.

- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. The Group 1 miscellaneous process vent emissions from the off gas knock-out drum (D-400) are routed to the VRU Flare and associated flare gas recovery system FGRS3.

(2) Vapor Recovery Unit VRU 400 for the Coker 2, permitted in 2008, to be installed as part of the WRMP project. This unit is connected to the South Flare and associated flare gas recovery system FGRS1 (identified in Section D.35). This system is used to recover or 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 K-401), pumps, pressure relief devices, sampling connection systems, open-ended valves or lines, and instrumentation and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.6]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. The Group 1 miscellaneous process vent emissions at the VRU 400 are routed to the South Flare and associated flare gas recovery system FGRS1.

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control VOC emissions emitted during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.7]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. The Group 1 miscellaneous process vent emissions from the off gas knock-out drum (D-22) are routed to the Alky Flare and associated flare gas recovery system FGRS3.

(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 the Alky Flare and associated flare gas recovery system FGRS3 (identified in Section D.35). This system is used to recover or control 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 the Alky Flare or FGRS3 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 and heat exchange systems. The following specific units are considered to be affected facilities: [Section D.8]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.

(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 the UIU Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the MSAT II Compliance project approved in 2011 for construction, one (1) new C-250 Naphtha Splitter, a benzene saturation reactor system, and associated equipment (collectively identified as the Naphtha Splitter Unit) will be installed in the ISOM. The following specific units are considered to be affected facilities: [Section D.9]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. The Group 1 and Group 2 miscellaneous process vent emissions from the off gas knock-out drum (ISOM D-18) are routed to the UIU Flare and associated flare gas recovery system FGRS4.

(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 following specific units are considered to be affected facilities: [Section D.10]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. The two (2) Group 2 miscellaneous process vent emissions from the ARU are routed to the 4UF Flare and associated flare gas recovery system FGRS4.

(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. The BOU is connected to the 4UF Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, the BOU heater F-401 will be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr. The following specific units are considered to be affected facilities: [Section D.11]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.

(n) Butane, Propane and Propylene Storage and Loading Facilities, identified as Unit ID 604. The following specific units are considered to be affected facilities: [Section D.14]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.

(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 C-2 Splitter Tower will be shut down and permanently decommissioned as part of the MSAT II Compliance project, approved in 2011 for construction. The unit now consists of the C2 D-18 flare gas separator, the D-24 knock-out drum and associated piping.

The No. 3 Ultraformer is connected to the UIU flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, preparation of equipment for maintenance and reactor regenerations. The following specific units are considered to be affected facilities: [Section D.15]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. The Group 1 miscellaneous process vent emissions from the C2 D-18 flare gas separator are routed to the UIU Flare and associated flare gas recovery system FGRS4.

(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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. The following specific units are considered to be affected facilities: [Section D.16]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. The Group 2 miscellaneous process vent emissions from the 4UF are routed to the 4UF Flare and associated flare gas recovery system FGRS4.

(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 following specific units are considered to be affected facilities: [Section D.17]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. There is one (1) Group 2 miscellaneous process vent at the HU unit.

(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 H2S. The following specific units are considered to be affected facilities: [Section D.18]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. There is one (1) Group 2 miscellaneous process vent at the DDU unit.
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.

(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 CFHU is connected to the No. 4 Ultraformer flare stack. The No. 4 Ultraformer Flare Stack, S/V 2224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.19]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.

(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 following specific units are considered to be affected facilities: [Section D.20]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. The Group 1 miscellaneous process vent emissions from the CRU are routed to the UIU Flare and associated flare gas recovery system FGRS4.

(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 oF 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 following specific units are considered to be affected facilities: [Section D.21]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. The Group 1 miscellaneous process vent emissions from the FCU500 are routed to the VRU Flare and associated flare gas recovery system FGRS3.

(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 oF 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 following specific units are considered to be affected facilities: [Section D.22]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.

(x) A portion of No. 3 Stanolind Power Station (SPS) identified as Unit ID 503. The following specific units are considered to be affected facilities: [Section D.24]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.

(y) Hazardous Waste Treatment System. The following specific units are considered to be affected facilities: [Section D.25]

- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including wastewater tanks and wastewater streams associated with the dewatering system, individual drain systems, oil water separators, and closed vent systems and control devices.

(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. As part of the Lakefront Upgrades (LFU) Project, approved in 2014 for modification, the larger solids in the wastewater will be removed in the new Solids Collection System. Then the wastewater will be routed to tanks TK-5050, TK-5051 and TK-5052, which will operate in parallel and serve as oil-water separators, equalization, and stormwater surge. Floating oil will be separated and skimmed from the tanks and recycled. The water will be routed to the new Dissolved Nitrogen Floatation (DNF) Units to remove suspended solids and oil, which will be 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 final filters before being returned to Lake Michigan. The following specific units are considered to be affected facilities: [Section D.26]

- Dissolved Nitrogen Floatation (DNF) System
- TK-5050
- TK-5051
- TK-5052
- TK-303
- TK-304
- TK-562
- Solids collection system
- TK-101
- TK-102
- TK-103
- TK-104
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including the Dissolved Nitrogen Floatation (DNF) System, tanks TK-5050, TK-5051, and TK-5052, float and sludge handling tanks TK-303, TK-304, and TK-562, the solids collection system, the four tanks in the brine treatment system (TK-101, TK-102, TK-103 and TK-104), individual drain systems, oil water separators, and closed vent systems and control devices.

(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. The following specific units are considered to be affected facilities: [Section D.27]

- TK-3559
- TK-3560
- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including wastewater tanks and wastewater streams associated with the dewatering system, individual drain systems, oil water separators, and closed vent systems and control devices. TK-3559 and TK-3560 shall comply with the applicable wastewater requirements in 40 CFR 63, Subpart CC.
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. There is one (1) Group 2 miscellaneous process vent at Oil Movements.

The following are Group 1 storage vessels meeting the criteria specified in 40 CFR 63, Subpart CC:

- Tank 3529
- Tank 3901
- Tank 3902
- Tank 3915
- Tank 3916
- Tank 3917
- Tank 3918
- Tank 3919
- Tank 3920
- Tank 3474
- Tank 3475
- Tank 3476
- Tank 3477
- Tank 3480
- Tank 3482
- Tank 3483
- Tank 3484
- Tank 3486
- Tank 3487
- Tank 3488
- Tank 3489
- Tank 3493
- Tank 3510
- Tank 3511
- Tank 3512
- Tank 3513
- Tank 3514
- Tank 3525
- Tank 3526
- Tank 3527
- Tank 3528
- Tank 3531
- Tank 3532
- Tank 3533
- Tank 3534

- Tank 3553
- Tank 3554
- Tank 3601
- Tank 3605
- Tank 3622
- Tank 3624
- Tank 3629
- Tank 3631
- Tank 3633
- Tank 3635
- Tank 3639
- Tank 3641
- Tank 3701
- Tank 3702
- Tank 3704
- Tank 3705
- Tank 3706
- Tank 3707
- Tank 3710
- Tank 3715
- Tank 3716
- Tank 3728
- Tank 3900
- Tank 3904
- Tank 3905
- Tank 3907
- Tank 3909
- Tank 3911
- Tank 3912
- Tank 3914

The following are Group 2 storage vessels under 40 CFR 63, Subpart CC:

- TK-3228
- TK-3234
- TK-3872
- Tank 3708
- Tank 3709
- TK-3711
- TK-3712
- TK-3726
- Tank 3727
- Tank 3730
- TK-3733
- TK-3734
- TK-3735
- TK-3906
- TK-3908
- TK-3910
- TK-3913
- TK-3505
- TK-3509
- TK-3491
- TK-3496

- TK-3498
- TK-3499
- TK-3500
- TK-3546
- TK-3547
- TK-3548
- Tank 3549
- TK-3867
- TK-3868
- TK-3869
- TK-3876
- Tank 3600
- Tank 3602
- Tank 3604
- TK-3606
- TK-3607
- Tank 3558
- TK-2279
- TK-3569
- TK-3571
- TK-3572
- TK-3609
- TK-3610
- TK-3611
- TK-3613
- Tank 3490
- Tank 3495

(cc) The Mechanical Shop, identified as Unit 693. The following specific units are considered to be affected facilities: [Section D.29]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.

(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 following specific units are considered to be affected facilities: [Section D.30]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- All gasoline loading racks classified under SIC code 2911 meeting the criteria specified in 40 CFR 63, Subpart CC.

(ee) Cooling Towers including the following: The following specific units are considered to be affected facilities: [Section D.31]

- Cooling Tower 2

- Cooling Tower 3
- Cooling Tower 4
- Cooling Tower 5
- Cooling Tower 6
- Cooling Tower 7
- Cooling Tower 8
- Modular Cooling Tower System
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC.

(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. The following specific units are considered to be affected facilities: [Section D.32]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.

The following Group 2 storage vessels meeting the criteria specified in 40 CFR 63, Subpart CC:
- Tank 6126
- Tank 6127
- TK-3614
- TK-3615
- TK-3616
- TK-3617

(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 a contemporaneous project to the WRMP Project, gasoline loading at the Marine dock will cease. The following specific units are considered to be affected facilities: [Section D.34]

- BT-1
- BT-2
- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices. BT-1 and BT-2 shall comply with the applicable requirements in 40 CFR 63, Subpart CC.
- All marine vessel loading operations located at a petroleum refinery meeting the criteria specified in 40 CFR 63, subpart CC and the applicable criteria of 40 CFR 63, Subpart Y.

The following Group 2 storage vessels meeting the criteria specified in 40 CFR 63, Subpart CC:
- TK-3570
- TK-3573

(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 following specific units are considered to be affected facilities: [Section D.35]

- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.

The following flares shall comply with the requirements specified in 40 CFR 63, Subpart CC relating to the control of process vents.

- 4UF Flare
- FCU Flare
- UIU Flare
- VRU Flare
- Alky Flare
- DDU Flare
- GOHT Flare
- South Flare

(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 and heat exchange systems. This facility also contains area drains and an oil/water separator. The following specific units are considered to be affected facilities: [Section D.36]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.

(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 H2S. The DHT Unit was constructed in 2005/2006. The following specific units are considered to be affected facilities: [Section D.37]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.

(mm) 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 a wet scrubber/carbon canister system (identified as S-1). The facility is approved for construction in 2007, is operated as a batch process. The following specific units are considered to be affected facilities: [Section D.41]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.

(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 WRMP Project. The following specific units are considered to be affected facilities: [Section D.42]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC,
- All wastewater streams and treatment operations meeting the criteria specified in 40 CFR 63, Subpart CC including individual drain systems, oil water separators, and closed vent systems and control devices.
- All miscellaneous process vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. The Group 1 and Group 2 miscellaneous process vent emissions from the GOHT are routed to the GOHT Flare and associated flare gas recovery system FGRS2.

(oo) The New Hydrogen Unit (New HU), identified as Unit ID 801, owned and operated by Praxair, Inc. and constructed as part of the WRMP 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 following specific units are considered to be affected facilities: [Section D.43]

- All equipment leaks meeting the criteria specified in 40 CFR 63, Subpart CC including equipment leaks of HAP from pumps, compressors, pressure relief devices, sampling connection systems, open ended lines or valves.
- The HU Flare shall comply with the requirements specified in 40 CFR 63, Subpart CC relating to closed vent systems.

Insignificant Activities

(hh) One (1) cooling tower, identified as Cooling Tower 1, with a maximum capacity of 35,000 gpm. [40 CFR 63, Subpart CC]

- The heat exchange systems meeting the criteria specified in 40 CFR 63, Subpart CC.

Under 40 CFR 63, Subpart CC, applies to petroleum refining process units and to related emission points that are specified in 40 CFR 63, Subpart CC that are located at a plant site that meet the criteria under 40 CFR 63,Subpart CC.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

National Emissions Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

H.2.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.642, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1, for the emission unit(s) listed above, as specified in 40 CFR Part 63, Subpart CC, in accordance with the schedule in 40 CFR Part 63, Subpart CC.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

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

H.2.2 National Emissions Standards for Hazardous Air Pollutants for Petroleum Refineries [40 CFR Part 63, Subpart CC][326 IAC 20-16]

Pursuant to 40 CFR Part 63, Subpart CC, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart CC, which are incorporated by reference as 326 IAC 20-16 (included as Attachment E.iii to this permit), for the emission unit(s) listed above, as specified as follows.

1. 40 CFR 63.640 all except (b)
2. 40 CFR 63.641
3. 40 CFR 63.642 (a), (c), (d), (e), (f), (g), (i), (k), (m)
4. 40 CFR 63.643 (a), (b)
5. 40 CFR 63.644 (a), (c), (d), (e)
6. 40 CFR 63.645
7. 40 CFR 63.646
8. 40 CFR 63.647
9. 40 CFR 63.648 (a)(1), (b), (f), (g), (h), (i)
10. 40 CFR 63.649 (e)
11. 40 CFR 63.650
12. 40 CFR 63.651
13. 40 CFR 63.654
14. 40 CFR 63.655
15. 40 CFR 63.656
16. Table 1
17. Table 4
18. Table 5
19. Table 6

H.2.3 Standard of Performance for Storage Vessels for Bulk Gasoline Terminals [326 IAC 12-1][40 CFR 60, Subpart XX][326 IAC 20-16][40 CFR 63, Subpart CC]

Pursuant to 40 CFR Part 63, Subpart CC, the Permittee shall comply with the applicable provisions of 40 CFR Part 60, Subpart XX, which are incorporated by reference as 326 IAC 12 (included as Attachment C.x to this permit), as follows.

1. 40 CFR 60.502
2. 40 CFR 60.503

H.2.4 National Emissions Standards for Hazardous Air Pollutants for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) [40 CFR Part 63, Subpart R][326 IAC 20-10][40 CFR 63, Subpart CC]

Pursuant to 40 CFR Part 63, Subpart CC, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart R, which are incorporated by reference as 326 IAC 20-10 (included as Attachment E.i to this permit), as follows.

1. 40 CFR 63.421
2. 40 CFR 63.422 (a), (b), (c), (e)
3. 40 CFR 63.425 (a), (b), (c), (i)

4. 40 CFR 63.427 (a), (b)
5. 40 CFR 63.428 (b), (c), (g)(1), (h)(1), (h)(2), (h)(3), (k)
6. Table 1

SECTION H.3 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 63, Subpart UUU

Emissions Unit Description:

(d) The Sulfur Recovery Plant (SRP), 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 WRMP Project, increasing the capacity to 1,300 long tons per day of sulfur. Additional sulfur capacity can be achieved with oxygen enrichment in the C, D and E Claus trains as part of the original WRMP design with no increase in permitted emissions. The following specific units are considered to be affected facilities: [Section D.4]

- Under 40 CFR Part 63, Subpart UUU, the process vent or group of process vents on Claus or other types of sulfur recovery plant units or the tail gas treatment units servicing sulfur recover plants, that are associated with sulfur recovery at the Sulfur Recovery Plant (SRP) are affected sources pursuant to 40 CFR 63, Subpart UUU.
- Under 40 CFR 63, Subpart UUU, each bypass line serving a new, existing, or reconstructed 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. and associated bypass lines for any affected sources.

(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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. The following specific units are considered to be affected facilities: [Section D.16]

- Under 40 CFR Part 63, Subpart UUU, 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. The affected source includes vents that are used during the unit depressurization, purging, coke burn and catalyst rejuvenation.
- Under 40 CFR 63, Subpart UUU, each bypass line serving a new, existing, or reconstructed catalytic reforming 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. and associated bypass lines for any affected sources.

(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 following specific units are considered to be affected facilities: [Section D.21]

- Under 40 CFR Part 63, Subpart UUU, 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) at the units listed below are affected sources pursuant to 40 CFR 63, Subpart UUU.
- Under 40 CFR 63, Subpart UUU, each bypass line serving a new, existing, or reconstructed catalytic cracking 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. and associated bypass lines for any affected sources.

(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 following specific units are considered to be affected facilities: [Section D.22]

- Under 40 CFR Part 63, Subpart UUU, 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) at the units listed below are affected sources pursuant to 40 CFR 63, Subpart UUU.
- Under 40 CFR 63, Subpart UUU, each bypass line serving a new, existing, or reconstructed catalytic cracking 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. and associated bypass lines for any affected sources.

(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 following specific units are considered to be affected facilities: [Section D.35]

- 4UF Flare
- FCU Flare
- UIU Flare
- VRU Flare
- Alky Flare

Under 40 CFR 63, Subpart UUU, the Permittee shall comply with the requirements specified in 40 CFR 63, Subpart UUU for the above flares.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

National Emissions Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

H.3.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.1577, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1, for the emission unit(s) listed above, as specified in 40 CFR Part 63, Subpart UUU, in accordance with the schedule in 40 CFR Part 63, Subpart UUU.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

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

H.3.2 National Emissions Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units [40 CFR Part 63, Subpart UUU][326 IAC 20-50]

Pursuant to 40 CFR Part 63, Subpart UUU, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart UUU, which are incorporated by reference as 326 IAC 20-50 (included as Attachment E.iv to this permit), for the emission unit(s) listed above, as specified as follows.

1. 40 CFR 63.1560
2. 40 CFR 63.1561
3. 40 CFR 63.1562 all except (c)
4. 40 CFR 63.1563 (a), (b), (e)
5. 40 CFR 63.1564
6. 40 CFR 63.1565
7. 40 CFR 63.1566
8. 40 CFR 63.1567
9. 40 CFR 63.1568
10. 40 CFR 63.1569
11. 40 CFR 63.1570
12. 40 CFR 63.1571 (a)(1), (a)(2), (a)(3), (b), (c), (d), (e)
13. 40 CFR 63.1572
14. 40 CFR 63.1573
15. 40 CFR 63.1574
16. 40 CFR 63.1575
17. 40 CFR 63.1576
18. 40 CFR 63.1577
19. 40 CFR 63.1578
20. 40 CFR 63.1579
21. Table 1
22. Table 2
23. Table 3
24. Table 4
25. Table 5
26. Table 6
27. Table 7
28. Table 8
29. Table 9
30. Table 10
31. Table 11
32. Table 12
33. Table 13
34. Table 14
35. Table 15
36. Table 16
37. Table 17
38. Table 18
39. Table 19
40. Table 20
41. Table 21

42. Table 22
43. Table 23
44. Table 24
45. Table 25
46. Table 26
47. Table 27
48. Table 28
49. Table 29
50. Table 30
51. Table 31
52. Table 33
53. Table 34
54. Table 35
55. Table 36
56. Table 37
57. Table 38
58. Table 39
59. Table 40
60. Table 41
61. Table 42
62. Table 43
63. Table 44

SECTION H.4 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 63, Subpart EEEE

Emissions Unit Description:

Under 40 CFR 63, Subpart EEEE, the affected sources include storage tanks, transfer racks, containers, transport vehicles and equipment leak components that are not subject to emissions control requirements including, but not limited to the following:

(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. The following specific units are considered to be affected facilities: [Section D.27]

- D-424
- TK-57874
- TK-57867
- TK-51302
- TK-57900
- TK-51314
- TK-51301
- TK-51348
- TK-51347
- TK-51346
- TK-51345
- TK-51344
- TK-51317
- TK-51307
- TK-51303
- TK-51336
- TK-51334
- TK-57547
- TK-57868
- TK-57869
- TK- 57867
- Drum (55)
- TK-57874
- TK-C Station-5
- TK-C Station-3
- TK- 4UF (3744 gallons)
- TK-11PS
- TK-3SPS
- TK-CFU
- TK-West of CT#1
- TK-West of CT#2
- TK-East of Alky
- Miscellaneous Totes

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

National Emissions Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

H.4.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.2398, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1, for the emission unit(s) listed above, as specified in 40 CFR Part 63, Subpart EEEE, in accordance with the schedule in 40 CFR Part 63, Subpart EEEE.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

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

H.4.2 National Emissions Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) [40 CFR Part 63, Subpart EEEE][326 IAC 20-83]

Pursuant to 40 CFR Part 63, Subpart EEEE, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart EEEE, which are incorporated by reference as 326 IAC 20-83 (included as Attachment E.v to this permit), for the emission unit(s) listed above, as specified as follows.

1. 40 CFR 63.2330
2. 40 CFR 63.2334 (a)
3. 40 CFR 63.2338
4. 40 CFR 63.2342 (b), (d)
5. 40 CFR 63.2343
6. 40 CFR 63.2382
7. 40 CFR 63.2386
8. 40 CFR 63.2390
9. 40 CFR 63.2394
10. 40 CFR 63.2398
11. 40 CFR 63.2402
12. 40 CFR 63.2406
13. Table 1
14. Table 12

SECTION H.5 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 63, Subpart ZZZZ

Emissions Unit Description:

(oo) The New Hydrogen Unit (New HU), identified as Unit ID 801, owned and operated by Praxair, Inc. and constructed as part of the WRMP 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 NO_X. The New HU heater stacks have continuous emissions monitors (CEMs) for NO_X and CO. The following specific units are considered to be affected sources: [Section D.43]

(5) One (1) diesel-fueled emergency generator rated at 1,214 HP. [Section D.43]

Insignificant Activities

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

(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 not related to the WRMP project. [40 CFR 60, Subpart IIII][40 CFR 63, Subpart ZZZZ][Section A]

(y) Other activities associated with emergencies, including on-site fire training approved by the department and stationary fire pump engines not related to the WRMP project. [326 IAC 2-7-1(21)(G)(xxii)][40 CFR 60, Subpart IIII][40 CFR 63, Subpart ZZZZ][Section A]

(ee) The three (3) emergency diesel-fired fire pump engines, identified as Firepump 1, 2, and 3, per SPM 089-25488-00453, one rated at 359 HP and 2 rated at 460 HP. [40 CFR 60, Subpart IIII][40 CFR 63, Subpart ZZZZ][Section D.45]

Under 40 CFR Part 60, Subpart ZZZZ, the above units are affected sources.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

National Emissions Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

H.5.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.6665, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1, for the emission unit(s) listed above, as specified in 40 CFR Part 63, Subpart ZZZZ, in accordance with the schedule in 40 CFR Part 63, Subpart ZZZZ.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

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

H.5.2 National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines [40 CFR Part 63, Subpart ZZZZ][326 IAC 20-82]

Pursuant to 40 CFR Part 63, Subpart ZZZZ, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart ZZZZ, which are incorporated by reference as 326 IAC 20-82 (included as Attachment E.vi to this permit), for the emission unit(s) listed above, as specified as follows.

1. 40 CFR 63.6580
2. 40 CFR 63.6585 (a), (b), (c)
3. 40 CFR 63.6590
4. 40 CFR 63.6595 (a)(1), (a)(3), (a)(4), (a)(5), (c)
5. 40 CFR 63.6600
6. 40 CFR 63.6601
7. 40 CFR 63.6602
8. 40 CFR 63.6604
9. 40 CFR 63.6605
10 40 CFR 63.6610
11. 40 CFR 63.6611
12. 40 CFR 63.6612
13. 40 CFR 63.6615
14. 40 CFR 63.6620
15. 40.CFR 63.6625
16. 40 CFR 63.6630
17. 40 CFR 63.6635
18. 40 CFR 63.6640
19. 40 CFR 63.6645
20. 40 CFR 63.6650
21. 40 CFR 63.6655
22. 40 CFR 63.6660
23. 40 CFR 63.6665
24. 40 CFR 63.6675
25. Table 1a
26. Table 1b
27. Table 2a
28. Table 2b
29. Table 2c
30. Table 3
31. Table 4
32. Table 5
33. Table 6
34. Table 7
35. Table 8

SECTION H.6 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 63, Subpart DDDDD

Emissions Unit Description:

(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. The following specific units are considered to be affected facilities: [Section D.1]

- H-1X
- H-2
- H-3
- H-200
- H-300

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(b) Cokers. The following specific units are considered to be affected facilities: [Section D.2]

Coker 2: The following specific units are considered to be affected facilities:

- F-201
- F-202
- F-203

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(c) No. 12 Pipe Still, constructed in 1959 and to be modified as part of the WRMP 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 WRMP project. Also, as part of the WRMP Project, there will be upgrades made to the atmospheric and vacuum distillation towers and various heat exchangers and associated piping. The following specific units are considered to be affected facilities: [Section D.3]

- H-101A
- H-101B
- H-102

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(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 the UIU Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the MSAT II Compliance project approved in 2011 for construction, one (1) new C-250 Naphtha Splitter, a benzene saturation reactor system, and associated equipment (collectively identified as the Naphtha Splitter Unit) will be installed in the ISOM. The following specific units are considered to be affected facilities: [Section D.9]

- H-1

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(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 following specific units are considered to be affected facilities: [Section D.10]

- F-200A
- F-200B

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(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. The BOU is connected to the 4UF Flare and associated flare gas recovery system FGRS4 (identified in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. As part of the WRMP Project, the BOU heater F-401 will be modified by replacing burners, with rated capacity remaining at 35 mmBTU/hr. The following specific units are considered to be affected facilities: [Section D.11]

- F-401

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(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. D-1 will be upgraded to a two bed reactor as part of the WRMP project. The C-6 Ultraformate Splitter will be used as a Dehexanizer as part of the MSAT II Compliance project, approved in 2011 for construction. The following specific units are considered to be affected facilities: [Section D.16]

- F-1
- F-8A
- F-8B
- F-2
- F-3
- F-4
- F-5
- F-6
- F-7

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(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 following specific units are considered to be affected facilities: [Section D.17]

- B-501

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(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 following specific units are considered to be affected facilities: [Section D.18]

- B-301
- B-302

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(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 CFHU is connected to the No. 4 Ultraformer flare stack. The No. 4 Ultraformer Flare Stack, S/V 2224-06, is used to control VOC emissions during emergency situations, unit startups and shutdowns, and preparation of equipment for maintenance. The following specific units are considered to be affected facilities: [Section D.19]

- F-801A
- F-801B
- F-801C

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(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 following specific units are considered to be affected facilities: [Section D.20]

- F-101
- F-102A

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(x) A portion of No. 3 Stanolind Power Station (SPS) identified as Unit ID 503. The following specific units are considered to be affected facilities: [Section D.24]

- #31 Boiler
- #32 Boiler
- #33 Boiler
- #34 Boiler
- #36 Boiler

Under 40 CFR Part 63, Subpart DDDDD, the above boilers are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(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. The following specific units are considered to be affected facilities: [Section D.32]

- F-2
- F-300
- F-400

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(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 a contemporaneous project to the WRMP Project, gasoline loading at the Marine dock will cease. The following specific units are considered to be affected facilities: [Section D.34]

- F-100

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(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. The following specific units are considered to be affected facilities: [Section D.37]

- B-601A

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(mm) 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 a wet scrubber/carbon canister system (identified as S-1). The facility is approved for construction in 2007, is operated as a batch process. The following specific units are considered to be affected facilities: [Section D.41]

- C-1

Under 40 CFR Part 63, Subpart DDDDD, the above boiler is an affected source under the subcategory of units designated to burn light liquid fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(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 WRMP Project. The following specific units are considered to be affected facilities: [Section D.42]

- F-901A
- F-901B

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(oo) The New Hydrogen Unit (New HU), identified as Unit ID 801, owned and operated by Praxair, Inc. and constructed as part of the WRMP 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 NO_X. The New HU heater stacks have continuous emissions monitors (CEMs) for NO_X and CO. The following specific units are considered to be affected facilities: [Section D.43]

- HU-1
- HU-2

Under 40 CFR Part 63, Subpart DDDDD, the above process heaters are affected sources under the subcategory of units designated to burn gas 1 fuels as that term is defined in 40 CFR 63, Subpart DDDDD.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

National Emissions Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

H.6.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.7565, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1, for the emission unit(s) listed above, as specified in 40 CFR Part 63, Subpart DDDDD, in accordance with the schedule in 40 CFR Part 63, Subpart DDDDD.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

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

H.6.2 National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters [40 CFR Part 63, Subpart DDDDD][326 IAC 20-95]

Pursuant to 40 CFR Part 63, Subpart DDDDD, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart DDDDD, which are incorporated by reference as 326 IAC 20-95 (included as Attachment E.vii to this permit), for the emission unit(s) listed above, as specified as follows.

1. 40 CFR 63.7480
2. 40 CFR 63.7485
3. 40 CFR 63.7490
4. 40 CFR 63.7491
5. 40 CFR 63.7495 (a), (b), (d), (g)
6. 40 CFR 63.7499
7. 40 CFR 63.7500
8. 40 CFR 63.7501
9. 40 CFR 63.7505
10. 40 CFR 63.7510
11. 40 CFR 63.7515
12. 40 CFR 63.7520
13. 40 CFR 63.7521
14. 40 CFR 63.7522
15. 40 CFR 63.7525 except (b)
16. 40 CFR 63.7530
17. 40 CFR 63.7533
18. 40 CFR 63.7535
19. 40 CFR 63.7540
20. 40 CFR 63.7541
21. 40 CFR 63.7545
22. 40 CFR 63.7550
23. 40 CFR 63.7555
24. 40 CFR 63.7560
25. 40 CFR 63.7565
26. 40 CFR 63.7570
27. 40 CFR 63.7575
28. Table 1
29. Table 2
30. Table 3
31. Table 4
32. Table 5
33. Table 6
34. Table 7
35. Table 8
36. Table 9
37. Table 10

SECTION H.7 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 63, Subpart GGGGG

Emissions Unit Description:

(bb) The general facility remediation system, identified as Unit 999. Remediation includes multiple well point systems. The well point systems extract groundwater which may have a small hydrocarbon fraction. 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. [Section D.28]

(oo) The New Hydrogen Unit (New HU), identified as Unit ID 801, owned and operated by Praxair, Inc. and constructed as part of the WRMP 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 NO_X. The New HU heater stacks have continuous emissions monitors (CEMs) for NO_X and CO. [Section D.43]

Under 40 CFR Part 60, Subpart GGGGG, the above units are affected facilities.

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

National Emissions Standards for Hazardous Air Pollutants (NESHAP) Requirements [326 IAC 2-7-5(1)]

H.7.1 General Provisions Relating to National Emissions Standards for Hazardous Air Pollutants under 40 CFR Part 63 [326 IAC 20-1][40 CFR Part 63, Subpart A]

(a) Pursuant to 40 CFR 63.7955, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 20-1-1, for the emission unit(s) listed above, as specified in 40 CFR Part 63, Subpart GGGGG, in accordance with the schedule in 40 CFR Part 63, Subpart GGGGG.

(b) Pursuant to 40 CFR 63.10, the Permittee shall submit all required notifications and reports to:

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

H.7.2 National Emissions Standards for Hazardous Air Pollutants: Site Remediation [40 CFR Part 63, Subpart GGGGG][326 IAC 20-87]

Pursuant to 40 CFR Part 63, Subpart GGGGG, the Permittee shall comply with the applicable provisions of 40 CFR Part 63, Subpart GGGGG, which are incorporated by reference as 326 IAC 20-87 (included as Attachment E.viii to this permit), for the emission unit(s) listed above, as specified as follows.

1. 40 CFR 63.7880
2. 40 CFR 63.7881 (a), (b)(1-3), (b)(6), (c), (d)
3. 40 CFR 63.7882
4. 40 CFR 63.7883 all except (d)

5. 40 CFR 63.7884
6. 40 CFR 63.7885
7. 40 CFR 63.7886
8. 40 CFR 63.7887
9. 40 CFR 63.7888
10. 40 CFR 63.7890
11. 40 CFR 63.7891
12. 40 CFR 63.7892
13. 40 CFR 63.7893
14. 40 CFR 63.7895
15. 40 CFR 63.7896
16. 40 CFR 63.7897
17. 40 CFR 63.7898
18. 40 CFR 63.7900
19. 40 CFR 63.7901
20. 40 CFR 63.7902
21. 40 CFR 63.7903
22. 40 CFR 63.7905
23. 40 CFR 63.7906
24. 40 CFR 63.7907
25. 40 CFR 63.7908
26. 40 CFR 63.7910
27. 40 CFR 63.7911
28. 40 CFR 63.7912
29. 40 CFR 63.7913
30. 40 CFR 63.7915
31. 40 CFR 63.7916
32. 40 CFR 63.7917
33. 40 CFR 63.7918
34. 40 CFR 63.7920
35. 40 CFR 63.7921
36. 40 CFR 63.7922
37. 40 CFR 63.7925
38. 40 CFR 63.7926
39. 40 CFR 63.7927
40. 40 CFR 63.7928
41. 40 CFR 63.7935
42. 40 CFR 63.7936
43. 40 CFR 63.7937
44. 40 CFR 63.7938
45. 40 CFR 63.7940
46. 40 CFR 63.7941
47. 40 CFR 63.7942
48. 40 CFR 63.7943
49. 40 CFR 63.7944
50. 40 CFR 63.7945
51. 40 CFR 63.7946
52. 40 CFR 63.7947
53. 40 CFR 63.7950
54. 40 CFR 63.7951
55. 40 CFR 63.7952
56. 40 CFR 63.7953
57. 40 CFR 63.7955
58. 40 CFR 63.7956
59. 40 CFR 63.7957
60. Table 1

61. Table 2
62. Table 3

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
Part 70 Permit No.: T089-30396-00453

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 and ENFORCEMENT 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
Part 70 Permit No.: T089-30396-00453

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 **Page 2 of 2**

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: ______________________________

DRAFT

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
Compliance and Enforcement 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
Part 70 Permit No.: T089-30396-00453

Months: ___________ **to** ____________ **Year:** ______________

Page 1 of 2

This report shall be submitted quarterly based on a calendar year. Proper notice submittal under Section B –Emergency Provisions satisfies the reporting requirements of paragraph (a) of Section C-General Reporting. Any deviation from the requirements of this permit, the date(s) of each deviation, the probable cause of the deviation, and the response steps taken must 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: ____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
Compliance and Enforcement 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
Part 70 Permit No.: T089-30396-00453
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: ____

DRAFT

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
Compliance and Enforcement 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
Part 70 Permit No.:	T089-30396-00453
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: ____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
Compliance and Enforcement 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
Part 70 Permit No.:	T089-30396-00453
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: ____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
Compliance and Enforcement 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
Part 70 Permit No.: T089-30396-00453

Parameter: ____________________(Daily limitations, including average daily)
Facility: ____________________
Limit: ____________________(value) ______________ (units)

Quarter: __________________ **Year:** _______________

Day	Month	Month	Month	Day	Month	Month	Month
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: ____

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
Compliance and Enforcement Section
Part 70 Quarterly Report

Source Name: BP Products North America, Inc., Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394-0710
Part 70 Permit No.: T089-30396-00453

Parameter: ____________________(12 month limitations)
Facility: ____________________
Limit: ____________________(value) ______________ (units)

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: ____

Attachment C.vii

Part 70 Operating Permit No: T089-30396-00453

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart UU—Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture

Source: 47 FR 34143, Aug. 6, 1982, unless otherwise noted.

§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 suface.

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.

[47 FR 34143, Aug. 6, 1982, as amended at 65 FR 61762, Oct. 17, 2000]

§60.472 Standards for particulate matter.

(a) On and after the date on which §60.8(b) requires a performance test to be completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any saturator:

(1) Particulate matter in excess of:

(i) 0.04 kg/Mg (0.08 lb/ton) of asphalt shingle or mineral-surfaced roll roofing produced, or

(ii) 0.4 kg/Mg (0.8 lb/ton) of saturated felt or smooth-surfaced roll roofing produced;

(2) Exhaust gases with opacity greater than 20 percent; and

(3) Any visible emissions from a saturator capture system for more than 20 percent of any period of consecutive valid observations totaling 60 minutes. Saturators that were constructed before November 18, 1980, and that have not been reconstructed since that date and that become subject to these standards through modification are exempt from the visible emissions standard. Saturators that have been newly constructed or reconstructed since November 18, 1980 are subject to the visible emissions standard.

(b) On and after the date on which §60.8(b) requires a performance test to be completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any blowing still:

(1) Particulate matter in excess of 0.67 kg/Mg (1.3 lb/ton) of asphalt charged to the still when a catalyst is added to the still; and

(2) Particulate matter in excess of 0.71 kg/Mg (1.4 lb/ton) of asphalt charged to the still when a catalyst is added to the still and when No. 6 fuel oil is fired in the afterburner; and

(3) Particulate matter in excess of 0.60 kg/Mg (1.2 lb/ton) of asphalt charged to the still during blowing without a catalyst; and

(4) Particulate matter in excess of 0.64 kg/Mg (1.3 lb/ton) of asphalt charged to the still during blowing without a catalyst and when No. 6 fuel oil is fired in the afterburner; and

(5) Exhaust gases with an opacity greater than 0 percent unless an opacity limit for the blowing still when fuel oil is used to fire the afterburner has been established by the Administrator in accordance with the procedures in §60.474(g).

(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.

(d) 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 mineral handling and storage facility emissions with opacity greater than 1 percent.

[47 FR 34143, Aug. 6, 1982, as amended at 65 FR 61762, Oct. 17, 2000; 79 FR 11250, Feb. 27, 2014]

§60.473 Monitoring of operations.

(a) The owner or operator subject to the provisions of this subpart, and using either an electrostatic precipitator or a high velocity air filter to meet the emission limit in §60.472(a)(1) and/or (b)(1) shall continuously monitor and record the temperature of the gas at the inlet of the control device. The temperature monitoring instrument shall have an accuracy of ±15 °C (±25 °F) over its range.

(b) The owner or operator subject to the provisions of this subpart and using an afterburner to meet the emission limit in §60.472(a)(1) and/or (b)(1) shall continuously monitor and record the temperature in the combustion zone of the afterburner. The monitoring instrument shall have an accuracy of ±10 °C (±18 °F) over its range.

(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.

(d) The industry is exempted from the quarterly reports required under §60.7(c). The owner/operator is required to record and report the operating temperature of the control device during the performance test and, as required by §60.7(d), maintain a file of the temperature monitoring results for at least two years.

[47 FR 34143, Aug. 6, 1982, as amended at 65 FR 61762, Oct. 17, 2000]

§60.474 Test methods and procedures.

(a) For saturators, the owner or operator shall conduct performance tests required in §60.8 as follows:

(1) If the final product is shingle or mineral-surfaced roll roofing, the tests shall be conducted while 106.6-kg (235-lb) shingle is being produced.

(2) If the final product is saturated felt or smooth-surfaced roll roofing, the tests shall be conducted while 6.8-kg (15-lb) felt is being produced.

(3) If the final product is fiberglass shingle, the test shall be conducted while a nominal 100-kg (220-lb) shingle is being produced.

(b) 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).

(c) The owner or operator shall determine compliance with the particulate matter standards in §60.472 as follows:

(1) The emission rate (E) of particulate matter shall be computed for each run using the following equation:

$E=(c_s\ Q_{sd})/(PK)$

where:

E=emission rate of particulate matter, kg/Mg (lb/ton).

c_s = concentration of particulate matter, g/dscm (gr/dscf).

Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

P=asphalt roofing production rate or asphalt charging rate, Mg/hr (ton/hr).

K=conversion factor, 1000 g/kg [7000 (gr/lb)].

(2) Method 5A shall be used to determine the particulate matter concentration (c_s) and volumetric flow rate (Q_{sd}) of the effluent gas. For a saturator, the sampling time and sample volume for each run shall be at least 120 minutes and 3.00 dscm (106 dscf), and for the blowing still, at least 90 minutes or the duration of the coating blow or non-coating blow, whichever is greater, and 2.25 dscm (79.4 dscf).

(3) For the saturator, the asphalt roofing production rate (P) for each run shall be determined as follows: The amount of asphalt roofing produced on the shingle or saturated felt process lines shall be obtained by direct measurement. The asphalt roofing production rate is the amount produced divided by the time taken for the run.

(4) For the blowing still, the asphalt charging rate (P) shall be computed for each run using the following equation:

$P=(Vd)/(K'\ \theta)$

where:

P=asphalt charging rate to blowing still, Mg/hr (ton/hr).

V=volume of asphalt charged, m3 (ft3).

d=density of asphalt, kg/m3 (lb/ft3).

K′=conversion factor, 1000 kg/Mg (2000 lb/ton).

θ=duration of test run, hr.

(i) The volume (V) of asphalt charged shall be measured by any means accurate to within 10 percent.

(ii) The density (d) of the asphalt shall be computed using the following equation:

$$d = K_1 - K_2 T_i$$

Where:

d = Density of the asphalt, kg/m3 (lb/ft3)

K_1 = 1056.1 kg/m3 (metric units)

= 64.70 lb/ft3 (English Units)

K_2 = 0.6176 kg/(m3 °C) (metric units)

= 0.0694 lb/(ft3 °F) (English Units)

T_i = temperature at the start of the blow, °C ((°deg;F)

(5) Method 9 and the procedures in §60.11 shall be used to determine opacity.

(d) The Administrator will determine compliance with the standards in §60.472(a)(3) by using Method 22, modified so that readings are recorded every 15 seconds for a period of consecutive observations during representative conditions (in accordance with §60.8(c)) totaling 60 minutes. A performance test shall consist of one run.

(e) The owner or operator shall use the monitoring device in §60.473 (a) or (b) to monitor and record continuously the temperature during the particulate matter run and shall report the results to the Administrator with the performance test results.

(f) If at a later date the owner or operator believes that the emission limits in §60.472(a) and (b) are being met even though one of the conditions listed in this paragraph exist, he may submit a written request to the Administrator to repeat the performance test and procedure outlined in paragraph (c) of this section.

(1) The temperature measured in accordance with §60.473(a) is exceeding that measured during the performance test.

(2) The temperature measured in accordance with §60.473(b) is lower than that measured during the performance test.

(g) If fuel oil is to be used to fire an afterburner used to control emissions from a blowing still, the owner or operator may petition the Administrator in accordance with §60.11(e) of the General Provisions to establish an opacity standard for the blowing still that will be the opacity standard when fuel oil is used to fire the afterburner. To obtain this opacity standard, the owner or operator must request the Administrator to determine opacity during an initial, or subsequent, performance test when fuel oil is used to fire the afterburner. Upon receipt of the results of the performance test, the Administrator will make a finding concerning compliance with the mass standard for the blowing still. If the Administrator finds that the facility was in compliance with the mass standard during the performance test but failed to meet the zero opacity standard, the Administrator will establish and promulgate in the FEDERAL REGISTER an opacity standard for the blowing still that will be the opacity standard when fuel oil is used to fire the afterburner. When the afterburner is fired with natural gas, the zero percent opacity remains the applicable opacity standard.

[54 FR 6677, Feb. 14, 1989, as amended 54 FR 27016, June 27, 1989; 65 FR 61762, Oct. 17, 2000]

Attachment C.xiii

Part 70 Operating Permit No: T089-30396-00453

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart NNN—Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations

Source: 55 FR 26942, June 29, 1990, unless otherwise noted.

§60.660 Applicability and designation of affected facility.

(a) The provisions of this subpart apply to each affected facility designated in paragraph (b) of this section that is part of a process unit that produces any of the chemicals listed in §60.667 as a product, co-product, by-product, or intermediate, except as provided in paragraph (c).

(b) The affected facility is any of the following for which construction, modification, or reconstruction commenced after December 30, 1983:

(1) Each distillation unit not discharging its vent stream into a recovery system.

(2) Each combination of a distillation unit and the recovery system into which its vent stream is discharged.

(3) Each combination of two or more distillation units and the common recovery system into which their vent streams are discharged.

(c) Exemptions from the provisions of paragraph (a) of this section are as follows:

(1) Any distillation unit operating as part of a process unit which produces coal tar or beverage alcohols, or which uses, contains, and produces no VOC is not an affected facility.

(2) Any distillation unit that is subject to the provisions of subpart DDD is not an affected facility.

(3) Any distillation unit that is designed and operated as a batch operation is not an affected facility.

(4) Each affected facility that has a total resource effectiveness (TRE) index value greater than 8.0 is exempt from all provisions of this subpart except for §§60.662; 60.664 (e), (f), and (g); and 60.665 (h) and (l).

(5) Each affected facility in a process unit with a total design capacity for all chemicals produced within that unit of less than one gigagram per year is exempt from all provisions of this subpart except for the recordkeeping and reporting requirements in paragraphs (j), (l)(6), and (n) of §60.665.

(6) Each affected facility operated with a vent stream flow rate less than 0.008 scm/min is exempt from all provisions of this subpart except for the test method and procedure and the recordkeeping and reporting requirements in §60.664(g) and paragraphs (i), (l)(5), and (o) of §60.665.

(d) *Alternative means of compliance*—(1) *Option to comply with part 65.* Owners or operators of process vents that are subject to this subpart may choose to comply with the provisions of 40 CFR part 65, subpart D, to satisfy the requirements of §§60.662 through 60.665 and 60.668. The provisions of 40 CFR part 65 also satisfy the criteria of paragraphs (c)(4) and (6) of this section. Other provisions applying to an owner or operator who chooses to comply with 40 CFR part 65 are provided in 40 CFR 65.1.

(2) *Part 60, subpart A.* Owners or operators who choose to comply with 40 CFR part 65, subpart D, 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 those process vents. All sections and paragraphs of subpart A of this part that are not mentioned in this paragraph (d)(2) do not apply to owners or operators of process vents complying with 40 CFR part 65, subpart D, 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 D, must comply with 40 CFR part 65, subpart A.

(3) *Compliance date.* Owners or operators who choose to comply with 40 CFR part 65, subpart D, at initial startup shall comply with paragraphs (d)(1) and (2) of this section for each vent stream on and after the date on which the initial performance test 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 the initial startup, whichever date comes first.

(4) *Initial startup notification.* Each owner or operator subject to the provisions of this subpart that chooses to comply with 40 CFR part 65, subpart D, at initial startup shall notify the Administrator of the specific provisions of 40 CFR 65.63(a)(1), (2), or (3), with which the owner or operator has elected to comply. Notification shall be submitted with the notifications of initial startup required by 40 CFR 65.5(b).

[NOTE: The intent of these standards is to minimize the emissions of VOC through the application of best demonstrated technology (BDT). The numerical emission limits in these standards are expressed in terms of total organic compounds (TOC), measured as TOC less methane and ethane. This emission limit reflects the performance of BDT.]

[55 FR 26942, June 29, 2000, as amended at 65 FR 78279, Dec. 14, 2000; 79 FR 11251, Feb. 27, 2014]

§60.661 Definitions.

As used in this subpart, all terms not defined here shall have the meaning given them in the Act and in subpart A of part 60, and the following terms shall have the specific meanings given them.

Batch distillation operation means a noncontinuous distillation operation in which a discrete quantity or batch of liquid feed is charged into a distillation unit and distilled at one time. After the initial charging of the liquid feed, no additional liquid is added during the distillation operation.

Boiler means any enclosed combustion device that extracts useful energy in the form of steam.

By compound means by individual stream components, not carbon equivalents.

Continuous recorder means a data recording device recording an instantaneous data value at least once every 15 minutes.

Distillation operation means an operation separating one or more feed stream(s) into two or more exit stream(s), 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 vapor-phase as they approach equilibrium within the distillation unit.

Distillation unit means a device or vessel in which distillation operations occur, including all associated internals (such as trays or packing) and accessories (such as reboiler, condenser, vacuum pump, steam jet, etc.), plus any associated recovery system.

Flame zone means the portion of the combustion chamber in a boiler occupied by the flame envelope.

Flow indicator means a device which indicates whether gas flow is present in a vent stream.

Halogenated vent stream means any vent stream determined to have a total concentration (by volume) of compounds containing halogens of 20 ppmv (by compound) or greater.

Incinerator means any enclosed combustion device that is used for destroying organic compounds and does not extract energy in the form of steam or process heat.

Process heater means a device that transfers heat liberated by burning fuel to fluids contained in tubes, including all fluids except water that is heated to produce steam.

Process unit means equipment assembled and connected by pipes or ducts to produce, as intermediates or final products, one or more of the chemicals in §60.667. A process unit can operate independently if supplied with sufficient fuel or raw materials and sufficient product storage facilities.

Product means any compound or chemical listed in §60.667 that is produced for sale as a final product as that chemical, or for use in the production of other chemicals or compounds. By-products, co-products, and intermediates are considered to be products.

Recovery device means an individual unit of equipment, such as an absorber, carbon adsorber, or condenser, capable of and used for the purpose of recovering chemicals for use, reuse, or sale.

Recovery system means an individual recovery device or series of such devices applied to the same vent stream.

Total organic compounds (TOC) means those compounds measured according to the procedures in §60.664(b)(4). For the purposes of measuring molar composition as required in §60.664(d)(2)(i); hourly emissions rate as required in §60.664(d)(5) and §60.664(e); and TOC concentration as required in §60.665(b)(4) and §60.665(g)(4), those compounds which the Administrator has determined do not contribute appreciably to the formation of ozone are to be excluded. The compounds to be excluded are identified in Environmental Protection Agency's statements on ozone abatement policy for State Implementation Plans (SIP) revisions (42 FR 35314; 44 FR 32042; 45 FR 32424; 45 FR 48942).

TRE index value means a measure of the supplemental total resource requirement per unit reduction of TOC associated with an individual distillation vent stream, based on vent stream flow rate, emission rate of TOC net heating value, and corrosion properties (whether or not the vent stream is halogenated), as quantified by the equation given under §60.664(e).

Vent stream means any gas stream discharged directly from a distillation facility to the atmosphere or indirectly to the atmosphere after diversion through other process equipment. The vent stream excludes relief valve discharges and equipment leaks including, but not limited to, pumps, compressors, and valves.

§60.662 Standards.

Each owner or operator of any affected facility shall comply with paragraph (a), (b), or (c) of this section for each vent stream on and after the date on which the initial performance test required by §60.8 and §60.664 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 the initial start-up, whichever date comes first. Each owner or operator shall either:

(a) Reduce emissions of TOC (less methane and ethane) by 98 weight-percent, or to a TOC (less methane and ethane) concentration of 20 ppmv, on a dry basis corrected to 3 percent oxygen, whichever is less stringent. If a boiler or process heater is used to comply with this paragraph, then the vent stream shall be introduced into the flame zone of the boiler or process heater; or

(b) Combust the emissions in a flare that meets the requirements of §60.18; or

(c) Maintain a TRE index value greater than 1.0 without use of VOC emission control devices.

§60.663 Monitoring of emissions and operations.

(a) The owner or operator of an affected facility that uses an incinerator to seek to comply with the TOC emission limit specified under §60.662(a) shall install, calibrate, maintain, and operate according to manufacturer's specifications the following equipment:

(1) A temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater.

(i) Where an incinerator other than a catalytic incinerator is used, a temperature monitoring device shall be installed in the firebox.

(ii) Where a catalytic incinerator is used, temperature monitoring devices shall be installed in the gas stream immediately before and after the catalyst bed.

(2) A flow indicator that provides a record of vent stream flow to the incinerator at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each affected facility at a point closest to the inlet of each incinerator and before being joined with any other vent stream.

(b) The owner or operator of an affected facility that uses a flare to seek to comply with §60.662(b) shall install, calibrate, maintain and operate according to manufacturer's specifications the following equipment:

(1) A heat sensing device, such as an ultra-violet beam sensor or thermocouple, at the pilot light to indicate the continuous presence of a flame.

(2) A flow indicator that provides a record of vent stream flow to the flare at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each affected facility at a point closest to the flare and before being joined with any other vent stream.

(c) The owner or operator of an affected facility that uses a boiler or process heater to seek to comply with §60.662(a) shall install, calibrate, maintain and operate according to the manufacturer's specifications the following equipment:

(1) A flow indicator that provides a record of vent stream flow to the boiler or process heater at least once every hour for each affected facility. The flow indicator shall be installed in the vent stream from each distillation unit within an affected facility at a point closest to the inlet of each boiler or process heater and before being joined with any other vent stream.

(2) A temperature monitoring device in the firebox equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being measured expressed in degrees Celsius or ±0.5 °C, whichever is greater, for boilers or process heaters of less than 44 MW (150 million Btu/hr) heat input design capacity.

(d) Monitor and record the periods of operation of the boiler or process heater if the design heat input capacity of the boiler or process heater is 44 MW (150 million Btu/hr) or greater. The records must be readily available for inspection.

(e) The owner or operator of an affected facility that seeks to comply with the TRE index value limit specified under §60.662(c) 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:

(1) Where an absorber is the final recovery device in the recovery system:

(i) A scrubbing liquid temperature monitoring device having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater, and a specific gravity monitoring device having an accuracy of ±0.02 specific gravity units, each equipped with a continuous recorder, or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infrared, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(2) Where a condenser is the final recovery device in the recovery system:

(i) A condenser exit (product side) temperature monitoring device equipped with a continuous recorder and having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater, or

(ii) An organic monitoring device used to monitor organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(3) Where a carbon adsorber is the final recovery device unit in the recovery system:

(i) An integrating steam flow monitoring device having an accuracy of ±10 percent, and a carbon bed temperature monitoring device having an accuracy of ±1 percent of the temperature being monitored expressed in degrees Celsius or ±0.5 °C, whichever is greater, both equipped with a continuous recorder, or

(ii) An organic monitoring device used to indicate the concentration level of organic compounds exiting the recovery device based on a detection principle such as infra-red, photoionization, or thermal conductivity, each equipped with a continuous recorder.

(f) An owner or operator of an affected facility seeking to demonstrate compliance with the standards specified under §60.662 with control devices other than incinerator, boiler, process heater, or flare; or recovery device other than an absorber, condenser, or carbon adsorber shall provide to the Administrator information describing the operation of the control device or recovery device and the process parameter(s) which would indicate proper operation and maintenance of the device. The Administrator may request further information and will specify appropriate monitoring procedures or requirements.

[55 FR 26942, June 29, 1990, as amended at 65 FR 61774, Oct. 17, 2000]

§60.664 Test methods and procedures.

(a) For the purpose of demonstrating compliance with §60.662, all affected facilities shall be run at full operating conditions and flow rates during any performance test.

(b) The following methods in appendix A to this part, except as provided under §60.8(b), shall be used as reference methods to determine compliance with the emission limit or percent reduction efficiency specified under §60.662(a).

(1) Method 1 or 1A, as appropriate, for selection of the sampling sites. The control device inlet sampling site for determination of vent stream molar composition or TOC (less methane and ethane) reduction efficiency shall be prior to the inlet of the control device and after the recovery system.

(2) Method 2, 2A, 2C, or 2D, as appropriate, for determination of the gas volumetric flow rates.

(3) The emission rate correction factor, integrated sampling and analysis procedure of Method 3 shall be used to determine the oxygen concentration ($\%O_{2d}$) for the purposes of determining compliance with the 20 ppmv limit. The sampling site shall be the same as that of the TOC samples, and the samples shall be taken during the same time that the TOC samples are taken.

The TOC concentration corrected to 3 percent 0_2 (C_c) shall be computed using the following equation:

$$C_c = C_{TOC} \frac{17.9}{20.9 - \%O_{2d}}$$

where:

C_c = Concentration of TOC corrected to 3 percent O_2, dry basis, ppm by volume.

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

$\%O_{2d}$ = Concentration of O_2, dry basis, percent by volume.

(4) Method 18 to determine the concentration of TOC in the control device outlet and the concentration of TOC in the inlet when the reduction efficiency of the control device is to be determined.

(i) The 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 15-minute intervals.

(ii) The emission reduction (R) of TOC (minus methane and ethane) shall be determined using the following equation:

$$R = \frac{E_i - E_o}{E_i} \times 100$$

where:

R=Emission reduction, percent by weight.

E_i = Mass rate of TOC entering the control device, kg/hr (lb/hr).

E_o = Mass rate of TOC discharged to the atmosphere, kg/hr (lb/hr).

(iii) The mass rates of TOC (E_i, E_o) shall be computed using the following equations:

$$E_i = K_2 \left(\sum_{j=1}^{n} C_{ij} M_{ij} \right) Q_i$$

$$E_O = K_2 \left(\sum_{j=1}^{n} C_{oj} M_{oj} \right) Q_O$$

where:

C_{ij}, C_{oj} = Concentration of sample component “j” of the gas stream at the inlet and outlet of the control device, respectively, dry basis, ppm by volume.

M_{ij}, M_{oj} = Molecular weight of sample component “j” of the gas stream at the inlet and outlet of the control device, respectively, g/g-mole (lb/lb-mole).

Q_i, Q_o = Flow rate of gas stream at the inlet and outlet of the control device, respectively, dscm/min (dscf/min).

$K_2 = 2.494 \times 10^{-6}$ (1/ppm)(g-mole/scm) (kg/g) (min/hr) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.557×10^{-7} (1/ppm) (lb-mole/scf) (min/hr) (English units), where standard temperature for (lb-mole/scf) is 68 °F.

(iv) The TOC concentration (C_{TOC}) is the sum of the individual components and shall be computed for each run using the following equation:

$$C_{TOC} = \sum_{j=1}^{n} C_j$$

where:

C_{TOC} = Concentration of TOC (minus methane and ethane), dry basis, ppm by volume.

C_j = Concentration of sample components "j", dry basis, ppm by volume.

n=Number of components in the sample.

(c) When a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to seek to comply with §60.662(a), the requirement for an initial performance test is waived, in accordance with §60.8(b). However, the Administrator reserves the option to require testing at such other times as may be required, as provided for in section 114 of the Act.

(d) When a flare is used to seek to comply with §60.662(b), the flare shall comply with the requirements of §60.18.

(e) The following test methods in appendix A to this part, except as provided under §60.8(b), shall be used for determining the net heating value of the gas combusted to determine compliance under §60.662(b) and for determining the process vent stream TRE index value to determine compliance under §60.662(c).

(1)(i) Method 1 or 1A, as appropriate, for selection of the sampling site. The sampling site for the vent stream flow rate and molar composition determination prescribed in §60.664(e)(2) and (3) shall be, except for the situations outlined in paragraph (e)(1)(ii) of this section, prior to the inlet of any control device, prior to any post-distillation dilution of the stream with air, and prior to any post-distillation introduction of halogenated compounds into the process vent stream. No transverse site selection method is needed for vents smaller than 10 centimeters (4 inches) in diameter.

(ii) If any gas stream other than the distillation vent stream from the affected facility is normally conducted through the final recovery device.

(A) The sampling site for vent stream flow rate and molar composition shall be prior to the final recovery device and prior to the point at which the nondistillation stream is introduced.

(B) The efficiency of the final recovery device is determined by measuring the TOC concentration using Method 18 at the inlet to the final recovery device after the introduction of any nondistillation vent stream and at the outlet of the final recovery device.

(C) This efficiency is applied to the TOC concentration measured prior to the final recovery device and prior to the introduction of the nondistillation stream to determine the concentration of TOC in the distillation vent stream from the final recovery device. This concentration of TOC is then used to perform the calculations outlined in §60.664(e)(4) and (5).

(2) The molar composition of the process vent stream shall be determined as follows:

(i) Method 18 to measure the concentration of TOC including those containing halogens.

(ii) ASTM D1946-77 or 90 (Reapproved 1994) (incorporation by reference as specified in §60.17 of this part) to measure the concentration of carbon monoxide and hydrogen.

(iii) Method 4 to measure the content of water vapor.

(3) The volumetric flow rate shall be determined using Method 2, 2A, 2C, or 2D, as appropriate.

(4) The net heating value of the vent stream shall be calculated using the following equation:

$$H_T = K_1\left(\sum_{j=1}^{n} C_j H_j\right)$$

where:

H_T = Net heating value of the sample, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (77 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F).

K_1 = 1.74×10^{-7} (1/ppm) (g-mole/scm) (MJ/kcal) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.03×10^{-11} (1/ppm) (lb-mole/scf) (Btu/kcal) (English units) where standard temperature for (lb/mole/scf) is 68 °F.

C_j = Concentration on a wet basis of compound j in ppm, as measured for organics by Method 18 and measured for hydrogen and carbon monoxide by ASTM D1946-77 or 90 (Reapproved 1994) (incorporation by reference as specified in §60.17 of this part) as indicated in §60.664(e)(2).

H_j = Net heat of combustion of compound j, kcal/(g-mole) [kcal/(lb-mole)], based on combustion at 25 °C and 760 mm Hg (77 °F and 30 in. Hg).

The heats of combustion of vent stream components would be required to be determined using ASTM D2382-76 (incorporation by reference as specified in §60.17 of this part) if published values are not available or cannot be calculated.

(5) The emission rate of TOC in the vent stream shall be calculated using the following equation:

$$E_{TOC} = K_2\left[\sum_{j=1}^{n} C_j M_j\right] Q_s$$

where:

E_{TOC} = Measured emission rate of TOC, kg/hr (lb/hr).

K_2 = 2.494×10^{-6} (1/ppm) (g-mole/scm) (kg/g) (min/hr) (metric units), where standard temperature for (g-mole/scm) is 20 °C.

= 1.557×10^{-7} (1/ppm) (lb-mole/scf) (min/hr) (English units), where standard temperature for (lb-mole/scf) is 68 °F.

C_j = Concentration on a wet basis of compound j in ppm, as measured by Method 18 as indicated in §60.664(e)(2).

M_j = Molecular weight of sample j, g/g-mole (lb/lb-mole).

Q_s = Vent stream flow rate, scm/min (scf/min), at a temperature of 20 °C (68 °F).

(6) The total process vent stream concentration (by volume) of compounds containing halogens (ppmv, by compound) shall be summed from the individual concentrations of compounds containing halogens which were measured by Method 18.

(f) For purposes of complying with §60.662(c) the owner or operator of a facility affected by this subpart shall calculate the TRE index value of the vent stream using the equation for incineration in paragraph (e)(1) of this section for halogenated vent streams. The owner or operator of an affected facility with a nonhalogenated vent stream shall determine the TRE index value by calculating values using both the incinerator equation in (e)(1) and the flare equation in (e)(2) of this section and selecting the lower of the two values.

(1) The equation for calculating the TRE index value of a vent stream controlled by an incinerator is as follows:

$$TRE=\frac{1}{E_{TOC}}\left[a+b\left(Q_s\right)+c\left(Q_s\right)^{0.88}+d\left(Q_s\right)\left(H_T\right)+e\left(Q_s\right)^{0.88}\left(H_T\right)^{0.88}+f\left(Y_s\right)^{0.5}\right]$$

(i) Where for a vent stream flow rate that is greater than or equal to 14.2 scm/min (501 scf/min) at a standard temperature of 20 °C (68 °F):

TRE = TRE index value.

Q_s = Vent stream flow rate, scm/min (scf/min), at a temperature of 20 °C (68 °F).

H_T = Vent stream net heating value, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (68 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F) as in the definition of Q_s.

Y_s = Q_s for all vent stream categories listed in table 1 except for Category E vent streams where $Y_s = Q_sH_T/3.6$.

E_{TOC} = Hourly emissions of TOC, kg/hr (lb/hr).

a, b, c, d, e, and f are coefficients.

The set of coefficients that apply to a vent stream can be obtained from table 1.

TABLE 1. DISTILLATION NSPS TRE COEFFICIENTS FOR VENT STREAMS CONTROLLED BY AN INCINERATOR

DESIGN CATEGORY A1. FOR HALOGENATED PROCESS VENT STREAMS, IF 0 ≤ NET HEATING VALUE (MJ/scm) ≤ 3.5 OR IF 0 ≤ NET HEATING VALUE (Btu/scf) ≤ 94:

Q_s = Vent Stream Flow rate scm/min (scf/min)	a	b	c	d	e	f
14.2 ≤ Q_s ≤ 18.8	18.84466	0.26742	-0.20044	0	0	0.01025
(501 ≤ Q_s ≤ 664)	(41.54494)	(0.016896)	(-0.019194)	(0)	(0)	(0.003803)
18.8 < Q_s ≤ 699	19.66658	0.26742	-0.25332	0	0	0.01025
(664 < Q_s ≤ 24,700)	(43.35694)	(0.016696)	(-0.024258)	(0)	(0)	(0.003803)
699 < Q_s ≤ 1400	39.19213	0.29062	-0.25332	0	0	0.01449
(24,700 < Q_s ≤ 49,000)	(86.40297)	(0.018145)	(-0.024258)	(0)	(0)	(0.005376)
1400 < Q_s ≤ 2100	58.71768	0.30511	-0.25332	0	0	0.01775
(49,000 < Q_s ≤ 74,000)	(129.4490)	(0.019050)	(-0.024258)	(0)	(0)	(0.006585)
2100 < Q_s ≤ 2800	78.24323	0.31582	-0.25332	0	0	0.02049
(74,000 < Q_s ≤ 99,000)	(172.4950)	(0.019718)	(-0.024258)	(0)	(0)	(0.007602)
2800 < Q_s ≤ 3500	97.76879	0.32439	-0.25332	0	0	0.02291
(99,000 < Q_s ≤ 120,000)	(215.5411)	(0.020253)	(-0.024258)	(0)	(0)	(0.008500)

DESIGN CATEGORY A2. FOR HALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE < 3.5 (MJ/scm) OR IF NET HEATING VALUE < 94 (Btu/scf):

Q_s = Vent Stream Flow rate scm/min(scf/min)	a	b	c	d	e	f
$14.2 \le Q_s \le 18.8$	18.84466	0.26742	-0.20044	0	0	0.01025
$(501 \le Q_s \le 664)$	(41.54494)	(0.016696)	(-0.019194)	(0)	(0)	(0.003803)
$18.8 < Q_s \le 699$	19.66658	0.26742	-0.25332	0	0	0.01025
$(664 < Q_s \le 24,700)$	(43.35694)	(0.016696)	(-0.024258)	(0)	(0)	(0.003803)
$699 < Q_s \le 1400$	39.19213	0.29062	-0.25332	0	0	0.01449
$(24,700 < Q_s \le 49,000)$	(86.40297)	(0.018145)	(-0.024258)	(0)	(0)	(0.005376)
$1400 < Q_s \le 2100$	58.71768	0.30511	-0.25332	0	0	0.01775
$(49,000 < Q_s \le 74,000)$	(129.4490)	(0.019050)	(-0.024258)	(0)	(0)	(0.006585)
$2100 < Q_s \le 2800$	78.24323	0.31582	-0.25332	0	0	0.02049
$(74,000 < Q_s \le 99,000)$	(172.4950)	(0.019718)	(-0.024258)	(0)	(0)	(0.007602)
$2800 < Q_s \le 3500$	97.76879	0.32439	-0.25332	0	0	0.02291
$(99,000 < Q_s \le 120,000)$	(215.5411)	(0.020253)	(-0.024258)	(0)	(0)	(0.008500)

DESIGN CATEGORY B. FOR NONHALOGENATED PROCESS VENT STREAMS, IF 0 ≤ NET HEATING VALUE (MJ/scm) ≤ 0.48 OR IF 0 ≤ NET HEATING VALUE (Btu/scf) ≤ 13:

Q_s = Vent Stream Flow rate scm/min(scf/min)	a	b	c	d	e	f
$14.2 \le Q_s \le 1340$	8.54245	0.10555	0.09030	-0.17109	0	0.01025
$(501 \le Q_s \le 47,300)$	(18.83268)	(0.0065901)	(0.008647)	(-0.00039762)	(0)	(0.003803)
$1340 < Q_s \le 2690$	16.94386	0.11470	0.09030	-0.17109	0	0.01449
$(47,300 < Q_s \le 95,000)$	(37.35443)	(0.0071614)	(0.008647)	(-0.00039762)	(0)	(0.005376)
$2690 < Q_s \le 4040$	25.34528	0.12042	0.09030	-0.17109	0	0.01775
$(95,000 < Q_s \le 143,000)$	(55.87620)	(0.0075185)	(0.008647)	(-0.00039762)	(0)	(0.006585)

DESIGN CATEGORY C. FOR NONHALOGENTED PROCESS VENT STREAMS, IF 0.48 < NET HEATING VALUE (MJ/scm) ≤ 1.9 OR IF 13 < NET HEATING VALUE (Btu/scf) ≤ 51:

Q_s = Vent Stream Flow rate scm/min(scf/min)	a	b	c	d	e	f
$14.2 \le Q_s \le 1340$	9.25233	0.06105	0.31937	-0.16181	0	0.01025
$(501 \le Q_s \le 47,300)$	(20.39769)	(0.003812)	(0.030582)	(-0.00037605)	(0)	(0.003803)
$1340 < Q_s \le 2690$	18.36363	0.06635	0.31937	-0.16181	0	0.01449
$(47,300 < Q_s \le 95,000)$	(40.48446)	(0.004143)	(0.030582)	(-0.00037605)	(0)	(0.005376)
$2690 < Q_s \le 4040$	27.47492	0.06965	0.31937	-0.16181	0	0.01775
$(95,000 < Q_s \le 143,000)$	(60.57121)	(0.004349)	(0.030582)	(-0.00037605)	(0)	(0.006585)

DESIGN CATEGORY D. FOR NONHALOGENATED PROCESS VENT STREAMS, IF 1.9 < NET HEATING VALUE (MJ/scm) ≤ 3.6 OR IF 51 < NET HEATING VALUE (Btu/scf) ≤ 97:

Q_s = Vent Stream Flow rate scm/min(scf/min)	a	b	c	d	e	f
$14.2 \le Q_s \le 1180$	6.67868	0.06943	0.02582	0	0	0.01025
$(501 \le Q_s \le 41,700)$	(14.72382)	(0.004335)	(0.002472)	(0)	(0)	(0.003803)
$1180 < Q_s \le 2370$	13.21633	0.07546	0.02582	0	0	0.01449
$(41,700 < Q_s \le 83,700)$	(29.13672)	(0.004711)	(0.002472)	(0)	(0)	(0.005376)
$2370 < Q_s \le 3550$	19.75398	0.07922	0.02582	0	0	0.01775
$(83,700 < Q_s \le 125,000)$	(43.54962)	(0.004946)	(0.002472)	(0)	(0)	(0.006585)

DESIGN CATEGORY E. FOR NONHALOGENATED PROCESS VENT STREAMS, IF NET HEATING VALUE > 3.6 MJ/scm OR IF NET HEATING VALUE > 97 (Btu/scf):

Q_S = Vent Stream Flow rate scm/min(scf/min)	a	b	c	d	e	f
$14.2 \le Y_S \le 1180$	6.67868	0	0	-0.00707	0.02220	0.01025
$(501 \le Y_S \le 41{,}700)$	(14.72382)	(0)	(0)	(-0.0000164)	(0.0001174)	(0.003803)
$1180 < Y_S \le 2370$	13.21633	0	0	-0.00707	0.02412	0.01449
$(41{,}700 < Y_S \le 83{,}700)$	(29.13672)	(0)	(0)	(-0.0000164)	(0.0001276)	(0.005376)
$2370 < Y_S \le 3550$	19.75398	0	0	-0.00707	0.02533	0.01775
$(83{,}700 < Y_S \le 125{,}000)$	(43.54962)	(0)	(0)	(-0.0000164)	(0.0001340)	(0.006585)

(ii) Where for a vent stream flow rate that is less than 14.2 scm/min (501 scf/min) at a standard temperature of 20 °C (68 °F):

TRE = TRE index value.

Q_s = 14.2 scm/min (501 scf/min).

H_T = (FLOW) (HVAL)/Q_s.

Where the following inputs are used:

FLOW = Vent stream flow rate, scm/min (scf/min), at a temperature of 20 °C (68 °F).

HVAL = Vent stream net heating value, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (68 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F) as in the definition of Q_s.

$Y_s = Q_s$ for all vent stream categories listed in table 1 except for Category E vent streams where $Y_s = Q_s H_T/3.6$.

E_{TOC} = Hourly emissions of TOC, kg/hr (lb/hr).

a, b, c, d, e, and f are coefficients

The set of coefficients that apply to a vent stream can be obtained from table 1.

(2) The equation for calculating the TRE index value of a vent stream controlled by a flare is as follows:

$$TRE = \frac{1}{E_{TOC}}\left[a\left(Q_s\right)+b\left(Q_s\right)^{0.8}+c\left(Q_s\right)\left(H_T\right)+d\left(E_{TOC}\right)+e\right]$$

where:

TRE = TRE index value.

E_{TOC} = Hourly emissions of TOC, kg/hr (lb/hr).

Q_s = Vent stream flow rate, scm/min (scf/min), at a standard temperature of 20 °C (68 °F).

H_T = Vent stream net heating value, MJ/scm (Btu/scf), where the net enthalpy per mole of vent stream is based on combustion at 25 °C and 760 mm Hg (68 °F and 30 in. Hg), but the standard temperature for determining the volume corresponding to one mole is 20 °C (68 °F) as in the definition of Q_s.

a, b, c, d, and e are coefficients.

The set of coefficients that apply to a vent stream shall be obtained from table 2.

Table 2—Distillation NSPS TRE Coefficients for Vent Streams Controlled By a Flare

	a	b	c	d	e
H_T 11.2 MJ/scm	2.25	0.288	−0.193	−0.0051	2.08
(H_T 301 Btu/scf)	(0.140)	(0.0367)	(−0.000448)	(−0.0051)	(4.59)
H_T 11.2 MJ/scm	0.309	0.0619	−0.0043	−0.0034	2.08
(H_T 301 Btu/scf)	(0.0193)	(0.00788)	(−0.0000010)	(−0.0034)	(4.59)

(g) Each owner or operator of an affected facility seeking to comply with §60.660(c)(4) or §60.662(c) shall recalculate the TRE index value for that affected facility whenever process changes are made. Examples of process changes include changes in production capacity, feedstock type, or catalyst type, or whenever there is replacement, removal, or addition of recovery equipment. The TRE index value shall be recalculated based on test data, or on best engineering estimates of the effects of the change to the recovery system.

(1) Where the recalculated TRE index value is less than or equal to 1.0, the owner or operator shall notify the Administrator within 1 week of the recalculation and shall conduct a performance test according to the methods and procedures required by §60.664 in order to determine compliance with §60.662(a). Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(2) Where the initial TRE index value is greater than 8.0 and the recalculated TRE index value is less than or equal to 8.0 but greater than 1.0, the owner or operator shall conduct a performance test in accordance with §§60.8 and 60.664 and shall comply with §§60.663, 60.664 and 60.665. Performance tests must be conducted as soon as possible after the process change but no later than 180 days from the time of the process change.

(h) Any owner or operator subject to the provisions of this subpart seeking to demonstrate compliance with §60.660(c)(6) shall use Method 2, 2A, 2C, or 2D as appropriate, for determination of volumetric flow rate.

[55 FR 26942, June 29, 1990, as amended at 65 FR 61774, Oct. 17, 2000]

§60.665 Reporting and recordkeeping requirements.

(a) Each owner or operator subject to §60.662 shall notify the Administrator of the specific provisions of §60.662 (§60.662 (a), (b), or (c)) with which the owner or operator has elected to comply. Notification shall be submitted with the notification of initial start-up required by §60.7(a)(3). If an owner or operator elects at a later date to use an alternative provision of §60.662 with which he or she will comply, then the Administrator shall be notified by the owner or operator 90 days before implementing a change and, upon implementing the change, a performance test shall be performed as specified by §60.664 within 180 days.

(b) Each owner or operator subject to the provisions of this subpart shall keep an up-to-date, readily accessible record of the following data measured during each performance test, and also include the following data in the report of the initial performance test required under §60.8. Where a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater is used to comply with §60.662(a), a report containing performance test data need not be submitted, but a report containing the information in §60.665(b)(2)(i) is required. The same data specified in this section shall be submitted in the reports of all subsequently required performance tests where either the emission control efficiency of a control device, outlet concentration of TOC, or the TRE index value of a vent stream from a recovery system is determined.

(1) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(a) through use of either a thermal or catalytic incinerator:

(i) The average firebox temperature of the incinerator (or the average temperature upstream and downstream of the catalyst bed for a catalytic incinerator), measured at least every 15 minutes and averaged over the same time period of the performance testing, and

(ii) The percent reduction of TOC determined as specified in §60.664(b) achieved by the incinerator, or the concentration of TOC (ppmv, by compound) determined as specified in §60.664(b) at the outlet of the control device on a dry basis corrected to 3 percent oxygen.

(2) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(a) through use of a boiler or process heater:

(i) A description of the location at which the vent stream is introduced into the boiler or process heater, and

(ii) The average combustion temperature of the boiler or process heater with a design heat input capacity of less than 44 MW (150 million Btu/hr) measured at least every 15 minutes and averaged over the same time period of the performance testing.

(3) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(b) through use of a smokeless flare, flare design (i.e., steam-assisted, air-assisted or nonassisted), all visible emission readings, heat content determinations, flow rate measurements, and exit velocity determinations made during the performance test, continuous records of the flare pilot flame monitoring, and records of all periods of operations during which the pilot flame is absent.

(4) Where an owner or operator subject to the provisions of this subpart seeks to demonstrate compliance with §60.662(c):

(i) Where an absorber is the final recovery device in the recovery system, the exit specific gravity (or alternative parameter which is a measure of the degree of absorbing liquid saturation, if approved by the Administrator), and average exit temperature, of the absorbing liquid measured at least every 15 minutes and averaged over the same time period of the performance testing (both measured while the vent stream is normally routed and constituted), or

(ii) Where a condenser is the final recovery device in the recovery system, the average exit (product side) temperature measured at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is routed and constituted normally, or

(iii) Where a carbon adsorber is the final recovery device in the recovery system, the total steam mass flow measured at least every 15 minutes and averaged over the same time period of the performance test (full carbon bed cycle), temperature of the carbon bed after regeneration (and within 15 minutes of completion of any cooling cycle(s)), and duration of the carbon bed steaming cycle (all measured while the vent stream is routed and constituted normally), or

(iv) As an alternative to §60.665(b)(4) ((i), (ii) or (iii), the concentration level or reading indicated by the organics monitoring device at the outlet of the absorber, condenser, or carbon adsorber, measured at least every 15 minutes and averaged over the same time period of the performance testing while the vent stream is normally routed and constituted.

(v) All measurements and calculations performed to determine the TRE index value of the vent stream.

(c) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.663 (a) and (c) as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where a combustion device is used to comply with §60.662(a), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) For thermal incinerators, all 3-hour periods of operation during which the average combustion temperature was more than 28 °C (50 °F) below the average combustion temperature during the most recent performance test at which compliance with §60.662(a) was determined.

(2) For catalytic incinerators, all 3-hour periods of operation during which the average temperature of the vent stream immediately before the catalyst bed is more than 28 °C (50 °F) below the average temperature of the vent stream during the most recent performance test at which compliance with §60.662(a) was determined. The owner or operator also shall record all 3-hour periods of operation during which the average temperature difference across the catalyst bed is less than 80 percent of the average temperature difference of the device during the most recent performance test at which compliance with §60.662(a) was determined.

(3) All 3-hour periods of operation during which the average combustion temperature was more than 28 °C (50 °F) below the average combustion temperature during the most recent performance test at which compliance with §60.662(a) was determined for boilers or process heaters with a design heat input capacity of less than 44 MW (150 million Btu/hr).

(4) For boilers or process heaters, whenever there is a change in the location at which the vent stream is introduced into the flame zone as required under §60.662(a).

(d) Each owner or operator subject to the provisions of this subpart shall keep up to date, readily accessible continuous records of the flow indication specified under §60.663(a)(2), §60.663(b)(2) and §60.663(c)(1), as well as up-to-date, readily accessible records of all periods when the vent stream is diverted from the control device or has no flow rate.

(e) Each owner or operator subject to the provisions of this subpart who uses a boiler or process heater with a design heat input capacity of 44 MW (150 million Btu/hour) or greater to comply with §60.662(a) shall keep an up-to-date, readily accessible record of all periods of operation of the boiler or process heater. (Examples of such records could include records of steam use, fuel use, or monitoring data collected pursuant to other State or Federal regulatory requirements.)

(f) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the flare pilot flame monitoring specified under §60.663(b), as well as up-to-date, readily accessible records of all periods of operations in which the pilot flame is absent.

(g) Each owner or operator subject to the provisions of this subpart shall keep up-to-date, readily accessible continuous records of the equipment operating parameters specified to be monitored under §60.663(e), as well as up-to-date, readily accessible records of periods of operation during which the parameter boundaries established during the most recent performance test are exceeded. The Administrator may at any time require a report of these data. Where an owner or operator seeks to comply with §60.662(c), periods of operation during which the parameter boundaries established during the most recent performance tests are exceeded are defined as follows:

(1) Where an absorber is the final recovery device in a recovery system, and where an organic compound monitoring device is not used:

(i) All 3-hour periods of operation during which the average absorbing liquid temperature was more than 11 °C (20 °F) above the average absorbing liquid temperature during the most recent performance test, or

(ii) All 3-hour periods of operation during which the average absorbing liquid specific gravity was more than 0.1 unit above, or more than 0.1 unit below, the average absorbing liquid specific gravity during the most recent performance test (unless monitoring of an alternative parameter, which is a measure of the degree of absorbing liquid saturation, is approved by the Administrator, in which case he will define appropriate parameter boundaries and periods of operation during which they are exceeded).

(2) Where a condenser is the final recovery device in a system, and where an organic compound monitoring device is not used, all 3-hour periods of operation during which the average exit (product side) condenser operating temperature was more than 6 °C (1 1 °F) above the average exit (product side) operating temperature during the most recent performance test.

(3) Where a carbon adsorber is the final recovery device in a system, and where an organic compound monitoring device is not used:

(i) All carbon bed regeneration cycles during which the total mass steam flow was more than 10 percent below the total mass steam flow during the most recent performance test, or

(ii) All carbon bed regeneration cycles during which the temperature of the carbon bed after regeneration (and after completion of any cooling cycle(s)) was more than 10 percent greater than the carbon bed temperature (in degrees Celsius) during the most recent performance test.

(4) Where an absorber, condenser, or carbon adsorber is the final recovery device in the recovery system and where an organic compound monitoring device is used, all 3-hour periods of operation during which the average organic compound concentration level or reading of organic compounds in the exhaust gases is more than 20 percent greater than the exhaust gas organic compound concentration level or reading measured by the monitoring device during the most recent performance test.

(h) Each owner or operator of an affected facility subject to the provisions of this subpart and seeking to demonstrate compliance with §60.662(c) shall keep up-to-date, readily accessible records of:

(1) Any changes in production capacity, feedstock type, or catalyst type, or of any replacement, removal or addition of recovery equipment or a distillation unit;

(2) Any recalculation of the TRE index value performed pursuant to §60.664(g); and

(3) The results of any performance test performed pursuant to the methods and procedures required by §60.664(e).

(i) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the flow rate cutoff in §60.660(c)(6) shall keep up-to-date, readily accessible records to indicate that the vent stream flow rate is less than 0.008 scm/min (0.3 scf/min) and of any change in equipment or process operation that increases the operating vent stream flow rate, including a measurement of the new vent stream flow rate.

(j) Each owner or operator of an affected facility that seeks to comply with the requirements of this subpart by complying with the design production capacity provision in §60.660(c)(5) shall keep up-to-date, readily accessible records of any change in equipment or process operation that increases the design production capacity of the process unit in which the affected facility is located.

(k) Each owner and operator subject to the provisions of this subpart is exempt from the quarterly reporting requirements contained in §60.7(c) of the General Provisions.

(l) Each owner or operator that seeks to comply with the requirements of this subpart by complying with the requirements of §60.660 (c)(4), (c)(5), or (c)(6) or §60.662 shall submit to the Administrator semiannual reports of the following recorded information. The initial report shall be submitted within 6 months after the initial start-up date.

(1) Exceedances of monitored parameters recorded under §60.665 (c) and (g).

(2) All periods recorded under §60.665(d) when the vent stream is diverted from the control device or has no flow rate.

(3) All periods recorded under §60.665(e) when the boiler or process heater was not operating.

(4) All periods recorded under §60.665(f) in which the pilot flame of the flare was absent.

(5) Any change in equipment or process operation that increases the operating vent stream flow rate above the low flow exemption level in §60.660(c)(6), including a measurement of the new vent stream flow rate, as recorded under §60.665(i). These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed with the same time period to verify the recalculated flow value and to obtain the vent stream characteristics of heating value and $E_{TOC.}$ The performance test is subject to the requirements of

§60.8 of the General Provisions. Unless the facility qualifies for an exemption under the low capacity exemption status in §60.660(c)(5), the facility must begin compliance with the requirements set forth in §60.662.

(6) Any change in equipment or process operation, as recorded under paragraph (j) of this section, that increases the design production capacity above the low capacity exemption level in §60.660(c)(5) and the new capacity resulting from the change for the distillation process unit containing the affected facility. These must be reported as soon as possible after the change and no later than 180 days after the change. These reports may be submitted either in conjunction with semiannual reports or as a single separate report. A performance test must be completed within the same time period to obtain the vent stream flow rate, heating value, and E_{TOC}. The performance test is subject to the requirements of §60.8. The facility must begin compliance with the requirements set forth in §60.660(d) or §60.662. If the facility chooses to comply with §60.662, the facility may qualify for an exemption in §60.660(c)(4) or (6).

(7) Any recalculation of the TRE index value, as recorded under §60.665(h).

(m) The requirements of §60.665(l) remain in force until and unless EPA, in delegating enforcement authority to a State under section 111(c) of the Act, 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 §60.665(l), provided that they comply with the requirements established by the State.

(n) Each owner or operator that seeks to demonstrate compliance with §60.660(c)(5) must submit to the Administrator an initial report detailing the design production capacity of the process unit.

(o) Each owner or operator that seeks to demonstrate compliance with §60.660(c)(6) must submit to the Administrator an initial report including a flow rate measurement using the test methods specified in §60.664.

(p) The Administrator will specify appropriate reporting and recordkeeping requirements where the owner or operator of an affected facility complies with the standards specified under §60.662 other than as provided under §60.663(a), (b), (c) and (d).

[55 FR 26922, June 29, 1990; 55 FR 36932, Sept. 7, 1990, as amended at 60 FR 58237, Nov. 27, 1995; 65 FR 61778, Oct. 17, 2000; 65 FR 78279, Dec. 14, 2000; 79 FR 11251, Feb. 27, 2014]

§60.666 Reconstruction.

For purposes of this subpart "fixed capital cost of the new components," as used in §60.15, 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 December 30, 1983. 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.

§60.667 Chemicals affected by subpart NNN.

Chemical name	CAS No.*
Acetaldehyde	75-07-0
Acetaldol	107-89-1
Acetic acid	64-19-7
Acetic anhydride	108-24-7
Acetone	67-64-1
Acetone cyanohydrin	75-86-5
Acetylene	74-86-2
Acrylic acid	79-10-7
Acrylonitrile	107-13-1
Adipic acid	124-04-9

Chemical name	CAS No.*
Adiponitrile	111-69-3
Alcohols, C-11 or lower, mixtures	
Alcohols, C-12 or higher, mixtures	
Allyl chloride	107-05-1
Amylene	513-35-9
Amylenes, mixed	
Aniline	62-53-3
Benzene	71-43-2
Benzenesulfonic acid	98-11-3
Benzenesulfonic acid $C_{10\text{-}16}$-alkyl derivatives, sodium salts	68081-81-2
Benzoic acid, tech	65-85-0
Benzyl chloride	100-44-7
Biphenyl	92-52-4
Bisphenol A	80-05-7
Brometone	76-08-4
1,3-Butadiene	106-99-0
Butadiene and butene fractions	
n-Butane	106-97-8
1,4-Butanediol	110-63-4
Butanes, mixed	
1-Butene	106-98-9
2-Butene	25167-67-3
Butenes, mixed	
n-Butyl acetate	123-86-4
Butyl acrylate	141-32-2
n-Butyl alcohol	71-36-3
sec-Butyl alcohol	78-92-2
tert-Butyl alcohol	75-65-0
Butylbenzyl phthalate	85-68-7
Butylene glycol	107-88-0
tert-Butyl hydroperoxide	75-91-2
2-Butyne-1,4-diol	110-65-6
Butyraldehyde	123-72-8
Butyric anhydride	106-31-0
Caprolactam	105-60-2
Carbon disulfide	75-15-0
Carbon tetrabromide	558-13-4
Carbon tetrachloride	56-23-5
Chlorobenzene	108-90-7
2-Chloro-4-(ethylamino)-6-(isopropylamino)-s-triazine	1912-24-9
Chloroform	67-66-3
p-Chloronitrobenzene	100-00-5
Chloroprene	126-99-8
Citric acid	77-92-9

Chemical name	CAS No.*
Crotonaldehyde	4170-30-0
Crotonic acid	3724-65-0
Cumene	98-82-8
Cumene hydroperoxide	80-15-9
Cyanuric chloride	108-77-0
Cyclohexane	110-82-7
Cyclohexane, oxidized	68512-15-2
Cyclohexanol	108-93-0
Cyclohexanone	108-94-1
Cyclohexanone oxime	100-64-1
Cyclohexene	110-83-8
1,3-Cyclopentadiene	542-92-7
Cyclopropane	75-19-4
Diacetone alcohol	123-42-2
Dibutanized aromatic concentrate	
1,4-Dichlorobutene	110-57-6
3,4-Dichloro-1-butene	64037-54-3
Dichlorodifluoromethane	75-71-8
Dichlorodimethylsilane	75-78-5
Dichlorofluoromethane	75-43-4
-Dichlorohydrin	96-23-1
Diethanolamine	111-42-2
Diethylbenzene	25340-17-4
Diethylene glycol	111-46-6
Di-n-heptyl-n-nonyl undecyl phthalate	85-68-7
Di-isodecyl phthalate	26761-40-0
Diisononyl phthalate	28553-12-0
Dimethylamine	124-40-3
Dimethyl terephthalate	120-61-6
2,4-Dinitrotoluene	121-14-2
2,4-(and 2,6)-dinitrotoluene	121-14-2
	606-20-2
Dioctyl phthalate	117-81-7
Dodecene	25378-22-7
Dodecylbenzene, non linear	
Dodecylbenzenesulfonic acid	27176-87-0
Dodecylbenzenesulfonic acid, sodium salt	25155-30-0
Epichlorohydrin	106-89-8
Ethanol	64-17-5
Ethanolamine	141-43-5
Ethyl acetate	141-78-6
Ethyl acrylate	140-88-5
Ethylbenzene	100-41-4
Ethyl chloride	75-00-3

Chemical name	CAS No.*
Ethyl cyanide	107-12-0
Ethylene	74-85-1
Ethylene dibromide	106-93-4
Ethylene dichloride	107-06-2
Ethylene glycol	107-21-1
Ethylene glycol monobutyl	111-76-2
Ethylene glycol monoethyl ether	110-80-5
Ethylene glycol monoethyl ether acetate	111-15-9
Ethylene glycol monomethyl ether	109-86-4
Ethylene oxide	75-21-8
2-Ethylhexanal	26266-68-2
2-Ethylhexyl alcohol	104-76-7
(2-Ethylhexyl) amine	104-75-6
Ethylmethylbenzene	25550-14-5
6-Ethyl-1,2,3,4-tetrahydro 9,10-anthracenedione	15547-17-8
Formaldehyde	50-00-0
Glycerol	56-81-5
n-Heptane	142-82-5
Heptenes (mixed)	
Hexadecyl chloride	
Hexamethylene diamine	124-09-4
Hexamethylene diamine adipate	3323-53-3
Hexamethylenetetramine	100-97-0
Hexane	110-54-3
2-Hexenedinitrile	13042-02-9
3-Hexenedinitrile	1119-85-3
Hydrogen cyanide	74-90-8
Isobutane	75-28-5
Isobutanol	78-83-1
Isobutylene	115-11-7
Isobutyraldehyde	78-84-2
Isodecyl alcohol	25339-17-7
Isooctyl alcohol	26952-21-6
Isopentane	78-78-4
Isophthalic acid	121-91-5
Isoprene	78-79-5
Isopropanol	67-63-0
Ketene	463-51-4
Linear alcohols, ethoxylated, mixed	
Linear alcohols, ethoxylated, and sulfated, sodium salt, mixed	
Linear alcohols, sulfated, sodium salt, mixed	
Linear alkylbenzene	123-01-3
Magnesium acetate	142-72-3
Maleic anhydride	108-31-6

Chemical name	CAS No.*
Melamine	108-78-1
Mesityl oxide	141-79-7
Methacrylonitrile	126-98-7
Methanol	67-56-1
Methylamine	74-89-5
ar-Methylbenzenediamine	25376-45-8
Methyl chloride	74-87-3
Methylene chloride	75-09-2
Methyl ethyl ketone	78-93-3
Methyl iodide	74-88-4
Methyl isobutyl ketone	108-10-1
Methyl methacrylate	80-62-6
2-Methylpentane	107-83-5
1-Methyl-2-pyrrolidone	872-50-4
Methyl tert-butyl ether	
Naphthalene	91-20-3
Nitrobenzene	98-95-3
1-Nonene	27215-95-8
Nonyl alcohol	143-08-8
Nonylphenol	25154-52-3
Nonylphenol, ethoxylated	9016-45-9
Octene	25377-83-7
Oil-soluble petroleum sulfonate, calcium salt	
Oil-soluble petroleum sulfonate, sodium salt	
Pentaerythritol	115-77-5
n-Pentane	109-66-0
3-Pentenenitrile	4635-87-4
Pentenes, mixed	109-67-1
Perchloroethylene	127-18-4
Phenol	108-95-2
1-Phenylethyl hydroperoxide	3071-32-7
Phenylpropane	103-65-1
Phosgene	75-44-5
Phthalic anhydride	85-44-9
Propane	74-98-6
Propionaldehyde	123-38-6
Propionic acid	79-09-4
Propyl alcohol	71-23-8
Propylene	115-07-1
Propylene chlorohydrin	78-89-7
Propylene glycol	57-55-6
Propylene oxide	75-56-9
Sodium cyanide	143-33-9
Sorbitol	50-70-4

Chemical name	CAS No.*
Styrene	100-42-5
Terephthalic acid	100-21-0
1,1,2,2-Tetrachloroethane	79-34-5
Tetraethyl lead	78-00-2
Tetrahydrofuran	109-99-9
Tetra (methyl-ethyl) lead	
Tetramethyl lead	75-74-1
Toluene	108-88-3
Toluene-2,4-diamine	95-80-7
Toluene-2,4-(and, 2,6)-diisocyanate (80/20 mixture)	26471-62-5
Tribromomethane	75-25-2
1,1,1-Trichloroethane	71-55-6
1,1,2-Trichloroethane	79-00-5
Trichloroethylene	79-01-6
Trichlorofluoromethane	75-69-4
1,1,2-Trichloro-1,2,2-trifluoroethane	76-13-1
Triethanolamine	102-71-6
Triethylene glycol	112-27-6
Vinyl acetate	108-05-4
Vinyl chloride	75-01-4
Vinylidene chloride	75-35-4
m-Xylene	108-38-3
o-Xylene	95-47-6
p-Xylene	106-42-3
Xylenes (mixed)	1330-20-7
m-Xylenol	576-26-1

*CAS numbers refer to the Chemical Abstracts Registry numbers assigned to specific chemicals, isomers, or mixtures of chemicals. Some isomers or mixtures that are covered by the standards do not have CAS numbers assigned to them. The standards apply to all of the chemicals listed, whether CAS numbers have been assigned or not.

[55 FR 26942, June 29, 1990, as amended at 60 FR 58237, 58238, Nov. 27, 1995]

§60.668 Delegation of authority.

(a) In delegating implementation and enforcement authority to a State under §111(c) of the Act, the authorities contained in paragraph (b) of this section shall be retained by the Administrator and not transferred to a State.

(b) Authorities which will not be delegated to States: §60.663(e).

Attachment C.xvi

Part 70 Operating Permit No: T089-30396-00453

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

SOURCE: 71 FR 39172, July 11, 2006, unless otherwise noted.

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) and other persons as specified in paragraphs (a)(1) through (4) 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.

(1) Manufacturers of stationary CI ICE with a displacement of less than 30 liters per cylinder where the model year is:

(i) 2007 or later, for engines that are not fire pump engines;

(ii) The model year listed in Table 3 to this subpart or later model year, for fire pump engines.

(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.

(3) Owners and operators of any stationary CI ICE that are modified or reconstructed after July 11, 2005 and any person that modifies or reconstructs any stationary CI ICE after July 11, 2005.

(4) The provisions of §60.4208 of this subpart are applicable to all owners and operators of stationary CI ICE that commence construction after July 11, 2005.

(b) The provisions of this subpart are not applicable to stationary CI ICE being tested at a stationary CI ICE test cell/stand.

(c) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not required to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a) for a reason other than your status as an area source under this subpart. Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart applicable to area sources.

(d) Stationary CI ICE may be eligible for exemption from the requirements of this subpart as described in 40 CFR part 1068, subpart C (or the exemptions described in 40 CFR part 89, subpart J and 40 CFR part 94, subpart J, for engines that would need to be certified to standards in those parts), except that owners and operators, as well as manufacturers, may be eligible to request an exemption for national security.

(e) Owners and operators of facilities with CI ICE that are acting as temporary replacement units and that are located at a stationary source for less than 1 year and that have been properly certified as meeting the standards that would be applicable to such engine under the appropriate nonroad engine provisions, are not required to meet any other provisions under this subpart with regard to such engines.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

Emission Standards for Manufacturers

§60.4201 What emission standards must I meet for non-emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 through 2010 model year non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(c) Stationary CI internal combustion engine manufacturers must certify their 2011 model year and later non-emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same maximum engine power.

(d) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(3) Their 2013 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(e) Stationary CI internal combustion engine manufacturers must certify the following non-emergency stationary CI ICE to the certification emission standards and other requirements for new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.110, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year non-emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(f) Notwithstanding the requirements in paragraphs (a) through (c) of this section, stationary non-emergency CI ICE identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 1 to 40 CFR 1042.1 identifies 40 CFR part 1042 as being applicable, 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the Federal Aid Highway System (FAHS); and

(2) Marine offshore installations.

(g) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (e) of this section that are applicable to the model year, maximum engine power, and displacement of the reconstructed stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37967, June 28, 2011]

§60.4202 What emission standards must I meet for emergency engines if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (a)(1) through (2) of this section.

(1) For engines with a maximum engine power less than 37 KW (50 HP):

(i) The certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants for model year 2007 engines, and

(ii) The certification emission standards for new nonroad CI engines in 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, 40 CFR 1039.115, and table 2 to this subpart, for 2008 model year and later engines.

(2) For engines with a maximum engine power greater than or equal to 37 KW (50 HP), the certification emission standards for new nonroad CI engines for the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants beginning in model year 2007.

(b) Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later emergency stationary CI ICE with a maximum engine power greater than 2,237 KW (3,000 HP) and a displacement of less than 10 liters per cylinder that are not fire pump engines to the emission standards specified in paragraphs (b)(1) through (2) of this section.

(1) For 2007 through 2010 model years, the emission standards in table 1 to this subpart, for all pollutants, for the same maximum engine power.

(2) For 2011 model year and later, the certification emission standards for new nonroad CI engines for engines of the same model year and maximum engine power in 40 CFR 89.112 and 40 CFR 89.113 for all pollutants.

(c) [Reserved]

(d) Beginning with the model years in table 3 to this subpart, stationary CI internal combustion engine manufacturers must certify their fire pump stationary CI ICE to the emission standards in table 4 to this subpart, for all pollutants, for the same model year and NFPA nameplate power.

(e) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE that are not fire pump engines to the certification emission standards for new marine CI engines in 40 CFR 94.8, as applicable, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2007 model year through 2012 emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder;

(2) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder;

(3) Their 2013 model year emergency stationary CI ICE with a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder; and

(4) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power greater than or equal to 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(f) Stationary CI internal combustion engine manufacturers must certify the following emergency stationary CI ICE to the certification emission standards and other requirements applicable to Tier 3 new marine CI engines in 40 CFR 1042.101, 40 CFR 1042.107, 40 CFR 1042.115, 40 CFR 1042.120, and 40 CFR 1042.145, for all pollutants, for the same displacement and maximum engine power:

(1) Their 2013 model year and later emergency stationary CI ICE with a maximum engine power less than 3,700 KW (4,958 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 15 liters per cylinder; and

(2) Their 2014 model year and later emergency stationary CI ICE with a maximum engine power less than 2,000 KW (2,682 HP) and a displacement of greater than or equal to 15 liters per cylinder and less than 30 liters per cylinder.

(g) Notwithstanding the requirements in paragraphs (a) through (d) of this section, stationary emergency CI internal combustion engines identified in paragraphs (a) and (c) may be certified to the provisions of 40 CFR part 94 or, if Table 2 to 40 CFR 1042.101 identifies Tier 3 standards as being applicable, the requirements applicable to Tier 3 engines in 40 CFR part 1042, if the engines will be used solely in either or both of the following locations:

(1) Areas of Alaska not accessible by the FAHS; and

(2) Marine offshore installations.

(h) Notwithstanding the requirements in paragraphs (a) through (f) of this section, stationary CI internal combustion engine manufacturers are not required to certify reconstructed engines; however manufacturers may elect to do so. The reconstructed engine must be certified to the emission standards specified in paragraphs (a) through (f) of this section that are applicable to the model year, maximum engine power and displacement of the reconstructed emergency stationary CI ICE.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§60.4203 How long must my engines meet the emission standards if I am a manufacturer of stationary CI internal combustion engines?

Engines manufactured by stationary CI internal combustion engine manufacturers must meet the emission standards as required in §§60.4201 and 60.4202 during the certified emissions life of the engines.

[76 FR 37968, June 28, 2011]

Emission Standards for Owners and Operators

§60.4204 What emission standards must I meet for non-emergency engines if I am an owner or operator of a stationary CI internal combustion engine?

(a) Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of less than 10 liters per cylinder must comply with the emission standards in table 1 to this subpart. Owners and operators of pre-2007 model year non-emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder must comply with the emission standards for new CI engines in §60.4201 for their 2007 model year and later stationary CI ICE, as applicable.

(c) Owners and operators of non-emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the following requirements:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 grams per kilowatt-hour (g/KW-hr) (12.7 grams per horsepower-hr (g/HP-hr)) when maximum engine speed is less than 130 revolutions per minute (rpm);

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012 and before January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) For engines installed on or after January 1, 2016, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 3.4 g/KW-hr (2.5 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $9.0 \cdot n^{-0.20}$ g/KW-hr ($6.7 \cdot n^{-0.20}$ g/HP-hr) where n (maximum engine speed) is 130 or more but less than 2,000 rpm; and

(iii) 2.0 g/KW-hr (1.5 g/HP-hr) where maximum engine speed is greater than or equal to 2,000 rpm.

(4) Reduce particulate matter (PM) emissions by 60 percent or more, or limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.15 g/KW-hr (0.11 g/HP-hr).

(d) Owners and operators of non-emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the not-to-exceed (NTE) standards as indicated in §60.4212.

(e) Owners and operators of any modified or reconstructed non-emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed non-emergency stationary CI ICE that are specified in paragraphs (a) through (d) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37968, June 28, 2011]

§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?

(a) Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of less than 10 liters per cylinder that are not fire pump engines must comply with the emission standards in Table 1 to this subpart. Owners and operators of pre-2007 model year emergency stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards in 40 CFR 94.8(a)(1).

(b) Owners and operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with the emission standards for new nonroad CI engines in §60.4202, for all pollutants, for the same model year and maximum engine power for their 2007 model year and later emergency stationary CI ICE.

(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.

(d) Owners and operators of emergency stationary CI engines with a displacement of greater than or equal to 30 liters per cylinder must meet the requirements in this section.

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/kW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

(e) Owners and operators of emergency stationary CI ICE with a displacement of less than 30 liters per cylinder who conduct performance tests in-use must meet the NTE standards as indicated in §60.4212.

(f) Owners and operators of any modified or reconstructed emergency stationary CI ICE subject to this subpart must meet the emission standards applicable to the model year, maximum engine power, and displacement of the modified or reconstructed CI ICE that are specified in paragraphs (a) through (e) of this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§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 over the entire life of the engine.

[76 FR 37969, June 28, 2011]

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, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.

(c) [Reserved]

(d) Beginning June 1, 2012, owners and operators of stationary CI ICE subject to this subpart with a displacement of greater than or equal to 30 liters per cylinder are no longer subject to the requirements of paragraph (a) of this section, and must use fuel that meets a maximum per-gallon sulfur content of 1,000 parts per million (ppm).

(e) Stationary CI ICE that have a national security exemption under §60.4200(d) are also exempt from the fuel requirements in this section.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

Other Requirements for Owners and Operators

§60.4208 What is the deadline for importing or installing stationary CI ICE produced in previous model years?

(a) After December 31, 2008, owners and operators may not install stationary CI ICE (excluding fire pump engines) that do not meet the applicable requirements for 2007 model year engines.

(b) After December 31, 2009, owners and operators may not install stationary CI ICE with a maximum engine power of less than 19 KW (25 HP) (excluding fire pump engines) that do not meet the applicable requirements for 2008 model year engines.

(c) After December 31, 2014, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 19 KW (25 HP) and less than 56 KW (75 HP) that do not meet the applicable requirements for 2013 model year non-emergency engines.

(d) After December 31, 2013, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 56 KW (75 HP) and less than 130 KW (175 HP) that do not meet the applicable requirements for 2012 model year non-emergency engines.

(e) After December 31, 2012, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 130 KW (175 HP), including those above 560 KW (750 HP), that do not meet the applicable requirements for 2011 model year non-emergency engines.

(f) After December 31, 2016, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power of greater than or equal to 560 KW (750 HP) that do not meet the applicable requirements for 2015 model year non-emergency engines.

(g) After December 31, 2018, owners and operators may not install non-emergency stationary CI ICE with a maximum engine power greater than or equal to 600 KW (804 HP) and less than 2,000 KW (2,680 HP) and a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder that do not meet the applicable requirements for 2017 model year non-emergency engines.

(h) In addition to the requirements specified in §§60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.

(i) The requirements of this section do not apply to owners or operators of stationary CI ICE that have been modified, reconstructed, and do not apply to engines that were removed from one existing location and reinstalled at a new location.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§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 that does not meet the standards applicable to non-emergency engines, 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.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

Compliance Requirements

§60.4210 What are my compliance requirements if I am a stationary CI internal combustion engine manufacturer?

(a) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of less than 10 liters per cylinder to the emission standards specified in §60.4201(a) through (c) and §60.4202(a), (b) and (d) using the certification procedures required in 40 CFR part 89, subpart B, or 40 CFR part 1039, subpart C, as applicable, and must test their engines as specified in those parts. For the purposes of this subpart, engines certified to the standards in table 1 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89. For the purposes of this subpart, engines certified to the standards in table 4 to this subpart shall be subject to the same requirements as engines certified to the standards in 40 CFR part 89, except that engines with NFPA nameplate power of less than 37 KW (50 HP) certified to model year 2011 or later standards shall be subject to the same requirements as engines certified to the standards in 40 CFR part 1039.

(b) Stationary CI internal combustion engine manufacturers must certify their stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder to the emission standards specified in §60.4201(d) and (e) and §60.4202(e) and (f) using the certification procedures required in 40 CFR part 94, subpart C, or 40 CFR part 1042, subpart C, as applicable, and must test their engines as specified in 40 CFR part 94 or 1042, as applicable.

(c) Stationary CI internal combustion engine manufacturers must meet the requirements of 40 CFR 1039.120, 1039.125, 1039.130, and 1039.135, and 40 CFR part 1068 for engines that are certified to the emission standards in 40 CFR part 1039. Stationary CI internal combustion engine manufacturers must meet the corresponding provisions of 40 CFR part 89, 40 CFR part 94 or 40 CFR part 1042 for engines that would be covered by that part if they were nonroad (including marine) engines. Labels on such engines must refer to stationary engines, rather than or in addition to nonroad or marine engines, as appropriate. Stationary CI internal combustion engine manufacturers must label their engines according to paragraphs (c)(1) through (3) of this section.

(1) Stationary CI internal combustion engines manufactured from January 1, 2006 to March 31, 2006 (January 1, 2006 to June 30, 2006 for fire pump engines), other than those that are part of certified engine families under the nonroad CI engine regulations, must be labeled according to 40 CFR 1039.20.

(2) Stationary CI internal combustion engines manufactured from April 1, 2006 to December 31, 2006 (or, for fire pump engines, July 1, 2006 to December 31 of the year preceding the year listed in table 3 to this subpart) must be labeled according to paragraphs (c)(2)(i) through (iii) of this section:

(i) Stationary CI internal combustion engines that are part of certified engine families under the nonroad regulations must meet the labeling requirements for nonroad CI engines, but do not have to meet the labeling requirements in 40 CFR 1039.20.

(ii) Stationary CI internal combustion engines that meet Tier 1 requirements (or requirements for fire pumps) under this subpart, but do not meet the requirements applicable to nonroad CI engines must be labeled according to 40 CFR 1039.20. The engine manufacturer may add language to the label clarifying that the engine meets Tier 1 requirements (or requirements for fire pumps) of this subpart.

(iii) Stationary CI internal combustion engines manufactured after April 1, 2006 that do not meet Tier 1 requirements of this subpart, or fire pumps engines manufactured after July 1, 2006 that do not meet the requirements for fire pumps under this subpart, may not be used in the U.S. If any such engines are manufactured in the U.S. after April 1, 2006 (July 1, 2006 for fire pump engines), they must be exported or must be brought into compliance with the appropriate standards prior to initial operation. The export provisions of 40 CFR 1068.230 would apply to engines for export and the manufacturers must label such engines according to 40 CFR 1068.230.

(3) Stationary CI internal combustion engines manufactured after January 1, 2007 (for fire pump engines, after January 1 of the year listed in table 3 to this subpart, as applicable) must be labeled according to paragraphs (c)(3)(i) through (iii) of this section.

(i) Stationary CI internal combustion engines that meet the requirements of this subpart and the corresponding requirements for nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate.

(ii) Stationary CI internal combustion engines that meet the requirements of this subpart, but are not certified to the standards applicable to nonroad (including marine) engines of the same model year and HP must be labeled according to the provisions in 40 CFR parts 89, 94, 1039 or 1042, as appropriate, but the words “stationary” must be included instead of “nonroad” or “marine” on the label. In addition, such engines must be labeled according to 40 CFR 1039.20.

(iii) Stationary CI internal combustion engines that do not meet the requirements of this subpart must be labeled according to 40 CFR 1068.230 and must be exported under the provisions of 40 CFR 1068.230.

(d) An engine manufacturer certifying an engine family or families to standards under this subpart that are identical to standards applicable under 40 CFR parts 89, 94, 1039 or 1042 for that model year may certify any such family that contains both nonroad (including marine) and stationary engines as a single engine family and/or may include any such family containing stationary engines in the averaging, banking and trading provisions applicable for such engines under those parts.

(e) Manufacturers of engine families discussed in paragraph (d) of this section may meet the labeling requirements referred to in paragraph (c) of this section for stationary CI ICE by either adding a separate label containing the information required in paragraph (c) of this section or by adding the words “and stationary” after the word “nonroad” or “marine,” as appropriate, to the label.

(f) Starting with the model years shown in table 5 to this subpart, stationary CI internal combustion engine manufacturers must add a permanent label stating that the engine is for stationary emergency use only to each new emergency stationary CI internal combustion engine greater than or equal to 19 KW (25 HP) that meets all the emission standards for emergency engines in §60.4202 but does not meet all the emission standards for non-emergency engines in §60.4201. The label must be added according to the labeling requirements specified in 40 CFR 1039.135(b). Engine manufacturers must specify in the owner's manual that operation of emergency engines is limited to emergency operations and required maintenance and testing.

(g) Manufacturers of fire pump engines may use the test cycle in table 6 to this subpart for testing fire pump engines and may test at the NFPA certified nameplate HP, provided that the engine is labeled as “Fire Pump Applications Only”.

(h) Engine manufacturers, including importers, may introduce into commerce uncertified engines or engines certified to earlier standards that were manufactured before the new or changed standards took effect until inventories are depleted, as long as such engines are part of normal inventory. For example, if the engine manufacturers' normal industry practice is to keep on hand a one-month supply of engines based on its projected sales, and a new tier of standards starts to apply for the 2009 model year, the engine manufacturer may manufacture engines based on the normal inventory requirements late in the 2008 model year, and sell those engines for installation. The engine manufacturer may not circumvent the provisions of §§60.4201 or 60.4202 by stockpiling engines that are built before new or changed standards take effect. Stockpiling of such engines beyond normal industry practice is a violation of this subpart.

(i) The replacement engine provisions of 40 CFR 89.1003(b)(7), 40 CFR 94.1103(b)(3), 40 CFR 94.1103(b)(4) and 40 CFR 1068.240 are applicable to stationary CI engines replacing existing equipment that is less than 15 years old.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37969, June 28, 2011]

§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 do all of the following, except as permitted under paragraph (g) of this section:

(1) Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions;

(2) Change only those emission-related settings that are permitted by the manufacturer; and

(3) 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 emission-related specifications, except as permitted in paragraph (g) of this section.

(d) If you are an owner or operator and must comply with the emission standards specified in §60.4204(c) or §60.4205(d), you must demonstrate compliance according to the requirements specified in paragraphs (d)(1) through (3) of this section.

(1) Conducting an initial performance test to demonstrate initial compliance with the emission standards as specified in §60.4213.

(2) Establishing operating parameters to be monitored continuously to ensure the stationary internal combustion engine continues to meet the emission standards. The owner or operator must petition the Administrator for approval of operating parameters to be monitored continuously. The petition must include the information described in paragraphs (d)(2)(i) through (v) of this section.

(i) Identification of the specific parameters you propose to monitor continuously;

(ii) A discussion of the relationship between these parameters and NO_X and PM emissions, identifying how the emissions of these pollutants change with changes in these parameters, and how limitations on these parameters will serve to limit NO_X and PM emissions;

(iii) A discussion of how you will establish the upper and/or lower values for these parameters which will establish the limits on these parameters in the operating limitations;

(iv) A discussion identifying the methods and the instruments you will use to monitor these parameters, as well as the relative accuracy and precision of these methods and instruments; and

(v) A discussion identifying the frequency and methods for recalibrating the instruments you will use for monitoring these parameters.

(3) For non-emergency engines with a displacement of greater than or equal to 30 liters per cylinder, conducting annual performance tests to demonstrate continuous compliance with the emission standards as specified in §60.4213.

(e) If you are an owner or operator of a modified or reconstructed stationary CI internal combustion engine and must comply with the emission standards specified in §60.4204(e) or §60.4205(f), you must demonstrate compliance according to one of the methods specified in paragraphs (e)(1) or (2) of this section.

(1) Purchasing, or otherwise owning or operating, an engine certified to the emission standards in §60.4204(e) or §60.4205(f), as applicable.

(2) Conducting a performance test to demonstrate initial compliance with the emission standards according to the requirements specified in §60.4212 or §60.4213, as appropriate. The test must be conducted within 60 days after the engine commences operation after the modification or reconstruction.

(f) If you own or operate an emergency stationary ICE, you must operate the emergency stationary ICE according to the requirements in paragraphs (f)(1) through (3) of this section. In order for the engine to be considered an emergency stationary ICE under this subpart, any operation other than emergency operation, maintenance and testing, emergency demand response, and operation in non-emergency situations for 50 hours per year, as described in paragraphs (f)(1) through (3) of this section, is prohibited. If you do not operate the engine according to the requirements in paragraphs (f)(1) through (3) of this section, the engine will not be considered an emergency engine under this subpart and must meet all requirements for non-emergency engines.

(1) There is no time limit on the use of emergency stationary ICE in emergency situations.

(2) You may operate your emergency stationary ICE for any combination of the purposes specified in paragraphs (f)(2)(i) through (iii) of this section for a maximum of 100 hours per calendar year. Any operation for non-emergency situations as allowed by paragraph (f)(3) of this section counts as part of the 100 hours per calendar year allowed by this paragraph (f)(2).

(i) Emergency stationary ICE may be operated for maintenance checks and readiness testing, provided that the tests are recommended by federal, state or local government, the manufacturer, the vendor, the regional transmission organization or equivalent balancing authority and transmission operator, or the insurance company associated with the engine. The owner or operator 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 calendar year.

(ii) Emergency stationary ICE may be operated for emergency demand response for periods in which the Reliability Coordinator under the North American Electric Reliability Corporation (NERC) Reliability Standard EOP-002-3, Capacity and Energy Emergencies (incorporated by reference, see §60.17), or other authorized entity as determined by the Reliability Coordinator, has declared an Energy Emergency Alert Level 2 as defined in the NERC Reliability Standard EOP-002-3.

(iii) Emergency stationary ICE may be operated for periods where there is a deviation of voltage or frequency of 5 percent or greater below standard voltage or frequency.

(3) Emergency stationary ICE may be operated for up to 50 hours per calendar year in non-emergency situations. The 50 hours of operation in non-emergency situations are counted as part of the 100 hours per calendar year for maintenance and testing and emergency demand response provided in paragraph (f)(2) of this section. Except as provided in paragraph (f)(3)(i) of this section, the 50 hours per calendar year for non-emergency situations cannot be used for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity.

(i) The 50 hours per year for non-emergency situations can be used to supply power as part of a financial arrangement with another entity if all of the following conditions are met:

(A) The engine is dispatched by the local balancing authority or local transmission and distribution system operator;

(B) The dispatch is intended to mitigate local transmission and/or distribution limitations so as to avert potential voltage collapse or line overloads that could lead to the interruption of power supply in a local area or region.

(C) The dispatch follows reliability, emergency operation or similar protocols that follow specific NERC, regional, state, public utility commission or local standards or guidelines.

(D) The power is provided only to the facility itself or to support the local transmission and distribution system.

(E) The owner or operator identifies and records the entity that dispatches the engine and the specific NERC, regional, state, public utility commission or local standards or guidelines that are being followed for dispatching the engine. The local balancing authority or local transmission and distribution system operator may keep these records on behalf of the engine owner or operator.

(ii) [Reserved]

(g) If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must demonstrate compliance as follows:

(1) If you are an owner or operator of a stationary CI internal combustion engine with maximum engine power less than 100 HP, you must keep a maintenance plan and records of conducted maintenance to demonstrate compliance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, if you do not install and configure the engine and control device according to the manufacturer's emission-related written instructions, or you change the emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of such action.

(2) If you are an owner or operator of a stationary CI internal combustion engine greater than or equal to 100 HP and less than or equal to 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.

(3) If you are an owner or operator of a stationary CI internal combustion engine greater than 500 HP, you must keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions. In addition, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer. You must conduct subsequent performance testing every 8,760 hours of engine operation or 3 years, whichever comes first, thereafter to demonstrate compliance with the applicable emission standards.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37970, June 28, 2011; 78 FR 6695, Jan. 30, 2013]

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 (e) of this section.

(a) The performance test must be conducted according to the in-use testing procedures in 40 CFR part 1039, subpart F, for stationary CI ICE with a displacement of less than 10 liters per cylinder, and according to 40 CFR part 1042, subpart F, for stationary CI ICE with a displacement of greater than or equal to 10 liters per cylinder and less than 30 liters per cylinder.

(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.

(d) Exhaust emissions from stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) must not exceed the NTE numerical requirements, rounded to the same number of decimal places as the applicable standard in §60.4204(a), §60.4205(a), or §60.4205(c), determined from the equation in paragraph (c) of this section.

Where:

STD = The standard specified for that pollutant in §60.4204(a), §60.4205(a), or §60.4205(c).

Alternatively, stationary CI ICE that are complying with the emission standards for pre-2007 model year engines in §60.4204(a), §60.4205(a), or §60.4205(c) may follow the testing procedures specified in §60.4213, as appropriate.

(e) Exhaust emissions from stationary CI ICE that are complying with the emission standards for new CI engines in 40 CFR part 1042 must not exceed the NTE standards for the same model year and maximum engine power as required in 40 CFR 1042.101(c).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§60.4213 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 greater than or equal to 30 liters per cylinder?

Owners and operators of stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder must conduct performance tests according to paragraphs (a) through (f) of this section.

(a) Each performance test must be conducted according to the requirements in §60.8 and under the specific conditions that this subpart specifies in table 7. The test must be conducted within 10 percent of 100 percent peak (or the highest achievable) load.

(b) You may not conduct performance tests during periods of startup, shutdown, or malfunction, as specified in §60.8(c).

(c) You must conduct three separate test runs for each performance test required in this section, as specified in §60.8(f). Each test run must last at least 1 hour.

(d) To determine compliance with the percent reduction requirement, you must follow the requirements as specified in paragraphs (d)(1) through (3) of this section.

(1) You must use Equation 2 of this section to determine compliance with the percent reduction requirement:

$$\frac{C_i - C_o}{C_i} \times 100 = R \qquad \text{(Eq. 2)}$$

Where:

C_i = concentration of NO_X or PM at the control device inlet,

C_o = concentration of NO_X or PM at the control device outlet, and

R = percent reduction of NO_X or PM emissions.

(2) You must normalize the NO_X or PM concentrations at the inlet and outlet of the control device to a dry basis and to 15 percent oxygen (O_2) using Equation 3 of this section, or an equivalent percent carbon dioxide (CO_2) using the procedures described in paragraph (d)(3) of this section.

$$C_{adj} = C_d \frac{5.9}{20.9 - \%\,O_2} \qquad \text{(Eq. 3)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

$\%O_2$ = Measured O_2 concentration, dry basis, percent.

(3) If pollutant concentrations are to be corrected to 15 percent O_2 and CO_2 concentration is measured in lieu of O_2 concentration measurement, a CO_2 correction factor is needed. Calculate the CO_2 correction factor as described in paragraphs (d)(3)(i) through (iii) of this section.

(i) Calculate the fuel-specific F_o value for the fuel burned during the test using values obtained from Method 19, Section 5.2, and the following equation:

$$F_o = \frac{0.209_{F_d}}{F_c} \qquad \text{(Eq. 4)}$$

Where:

F_o = Fuel factor based on the ratio of O_2 volume to the ultimate CO_2 volume produced by the fuel at zero percent excess air.

0.209 = Fraction of air that is O_2, percent/100.

F_d = Ratio of the volume of dry effluent gas to the gross calorific value of the fuel from Method 19, dsm3/J (dscf/106 Btu).

F_c = Ratio of the volume of CO_2 produced to the gross calorific value of the fuel from Method 19, dsm3/J (dscf/106 Btu).

(ii) Calculate the CO_2 correction factor for correcting measurement data to 15 percent O_2, as follows:

$$X_{CO_2} = \frac{5.9}{F_o} \qquad \text{(Eq. 5)}$$

Where:

X_{CO2} = CO_2 correction factor, percent.

5.9 = 20.9 percent O_2−15 percent O_2, the defined O_2 correction value, percent.

(iii) Calculate the NO_X and PM gas concentrations adjusted to 15 percent O_2 using CO_2 as follows:

$$C_{adj} = C_d \frac{X_{CO_2}}{\%CO_2} \qquad \text{(Eq. 6)}$$

Where:

C_{adj} = Calculated NO_X or PM concentration adjusted to 15 percent O_2.

C_d = Measured concentration of NO_X or PM, uncorrected.

$\%CO_2$ = Measured CO_2 concentration, dry basis, percent.

(e) To determine compliance with the NO_X mass per unit output emission limitation, convert the concentration of NO_X in the engine exhaust using Equation 7 of this section:

$$ER = \frac{C_d \times 1.912 \times 10^{-3} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 7)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_d = Measured NO_X concentration in ppm.

$1.912\text{x}10^{-3}$ = Conversion constant for ppm NO_X to grams per standard cubic meter at 25 degrees Celsius.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Brake work of the engine, in KW-hour.

(f) To determine compliance with the PM mass per unit output emission limitation, convert the concentration of PM in the engine exhaust using Equation 8 of this section:

$$ER = \frac{C_{adj} \times Q \times T}{\text{KW-hour}} \qquad \text{(Eq. 8)}$$

Where:

ER = Emission rate in grams per KW-hour.

C_{adj} = Calculated PM concentration in grams per standard cubic meter.

Q = Stack gas volumetric flow rate, in standard cubic meter per hour.

T = Time of test run, in hours.

KW-hour = Energy output of the engine, in KW.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

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?

(a) Owners and operators of non-emergency stationary CI ICE that are greater than 2,237 KW (3,000 HP), or have a displacement of greater than or equal to 10 liters per cylinder, or are pre-2007 model year engines that are greater than 130 KW (175 HP) and not certified, must meet the requirements of paragraphs (a)(1) and (2) of this section.

(1) Submit an initial notification as required in §60.7(a)(1). The notification must include the information in paragraphs (a)(1)(i) through (v) of this section.

(i) Name and address of the owner or operator;

(ii) The address of the affected source;

(iii) Engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement;

(iv) Emission control equipment; and

(v) Fuel used.

(2) Keep records of the information in paragraphs (a)(2)(i) through (iv) of this section.

(i) All notifications submitted to comply with this subpart and all documentation supporting any notification.

(ii) Maintenance conducted on the engine.

(iii) If the stationary CI internal combustion is a certified engine, documentation from the manufacturer that the engine is certified to meet the emission standards.

(iv) If the stationary CI internal combustion is not a certified engine, documentation that the engine meets the emission standards.

(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.

(d) If you own or operate an emergency stationary CI ICE with a maximum engine power more than 100 HP that operates or is contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in §60.4211(f)(2)(ii) and (iii) or that operates for the purposes specified in §60.4211(f)(3)(i), you must submit an annual report according to the requirements in paragraphs (d)(1) through (3) of this section.

(1) The report must contain the following information:

(i) Company name and address where the engine is located.

(ii) Date of the report and beginning and ending dates of the reporting period.

(iii) Engine site rating and model year.

(iv) Latitude and longitude of the engine in decimal degrees reported to the fifth decimal place.

(v) Hours operated for the purposes specified in §60.4211(f)(2)(ii) and (iii), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vi) Number of hours the engine is contractually obligated to be available for the purposes specified in §60.4211(f)(2)(ii) and (iii).

(vii) Hours spent for operation for the purposes specified in §60.4211(f)(3)(i), including the date, start time, and end time for engine operation for the purposes specified in §60.4211(f)(3)(i). The report must also identify the entity that dispatched the engine and the situation that necessitated the dispatch of the engine.

(2) The first annual report must cover the calendar year 2015 and must be submitted no later than March 31, 2016. Subsequent annual reports for each calendar year must be submitted no later than March 31 of the following calendar year.

(3) The annual report must be submitted electronically using the subpart specific reporting form in the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (*www.epa.gov/cdx*). However, if the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the written report must be submitted to the Administrator at the appropriate address listed in §60.4.

[71 FR 39172, July 11, 2006, as amended at 78 FR 6696, Jan. 30, 2013]

Special Requirements

§60.4215 What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(a) Stationary CI ICE with a displacement of less than 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the applicable emission standards in §§60.4202 and 60.4205.

(b) Stationary CI ICE that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are not required to meet the fuel requirements in §60.4207.

(c) Stationary CI ICE with a displacement of greater than or equal to 30 liters per cylinder that are used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands are required to meet the following emission standards:

(1) For engines installed prior to January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 17.0 g/KW-hr (12.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $45 \cdot n^{-0.2}$ g/KW-hr ($34 \cdot n^{-0.2}$ g/HP-hr) when maximum engine speed is 130 or more but less than 2,000 rpm, where n is maximum engine speed; and

(iii) 9.8 g/KW-hr (7.3 g/HP-hr) when maximum engine speed is 2,000 rpm or more.

(2) For engines installed on or after January 1, 2012, limit the emissions of NO_X in the stationary CI internal combustion engine exhaust to the following:

(i) 14.4 g/KW-hr (10.7 g/HP-hr) when maximum engine speed is less than 130 rpm;

(ii) $44 \cdot n^{-0.23}$ g/KW-hr ($33 \cdot n^{-0.23}$ g/HP-hr) when maximum engine speed is greater than or equal to 130 but less than 2,000 rpm and where n is maximum engine speed; and

(iii) 7.7 g/KW-hr (5.7 g/HP-hr) when maximum engine speed is greater than or equal to 2,000 rpm.

(3) Limit the emissions of PM in the stationary CI internal combustion engine exhaust to 0.40 g/KW-hr (0.30 g/HP-hr).

[71 FR 39172, July 11, 2006, as amended at 76 FR 37971, June 28, 2011]

§60.4216 What requirements must I meet for engines used in Alaska?

(a) Prior to December 1, 2010, owners and operators of stationary CI ICE with a displacement of less than 30 liters per cylinder located in areas of Alaska not accessible by the FAHS should refer to 40 CFR part 69 to determine the diesel fuel requirements applicable to such engines.

(b) Except as indicated in paragraph (c) of this section, manufacturers, owners and operators of stationary CI ICE with a displacement of less than 10 liters per cylinder located in areas of Alaska not accessible by the FAHS may meet the requirements of this subpart by manufacturing and installing engines meeting the requirements of 40 CFR parts 94 or 1042, as appropriate, rather than the otherwise applicable requirements of 40 CFR parts 89 and 1039, as indicated in sections §§60.4201(f) and 60.4202(g) of this subpart.

(c) Manufacturers, owners and operators of stationary CI ICE that are located in areas of Alaska not accessible by the FAHS may choose to meet the applicable emission standards for emergency engines in §60.4202 and §60.4205, and not those for non-emergency engines in §60.4201 and §60.4204, except that for 2014 model year and later non-emergency CI ICE, the owner or operator of any such engine that was not certified as meeting Tier 4 PM standards, must meet the applicable requirements for PM in §60.4201 and §60.4204 or install a PM emission control device that achieves PM emission reductions of 85 percent, or 60 percent for engines with a displacement of greater than or equal to 30 liters per cylinder, compared to engine-out emissions.

(d) The provisions of §60.4207 do not apply to owners and operators of pre-2014 model year stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS.

(e) The provisions of §60.4208(a) do not apply to owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS until after December 31, 2009.

(f) The provisions of this section and §60.4207 do not prevent owners and operators of stationary CI ICE subject to this subpart that are located in areas of Alaska not accessible by the FAHS from using fuels mixed with used lubricating oil, in volumes of up to 1.75 percent of the total fuel. The sulfur content of the used lubricating oil must be less than 200 parts per million. The used lubricating oil must meet the on-specification levels and properties for used oil in 40 CFR 279.11.

[76 FR 37971, June 28, 2011]

§60.4217 What emission standards must I meet if I am an owner or operator of a stationary internal combustion engine using special fuels?

Owners and operators of stationary CI ICE that do not use diesel fuel 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 §60.4204 or §60.4205 using such fuels and that use of such fuel is appropriate and reasonably necessary, considering cost, energy, technical feasibility, human health and environmental, and other factors, for the operation of the engine.

[76 FR 37972, June 28, 2011]

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.

Certified emissions 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 certified emissions 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 certified emissions 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).

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.

Date of manufacture means one of the following things:

(1) For freshly manufactured engines and modified engines, date of manufacture means the date the engine is originally produced.

(2) For reconstructed engines, date of manufacture means the date the engine was originally produced, except as specified in paragraph (3) of this definition.

(3) Reconstructed engines are assigned a new date of manufacture if the fixed capital cost of the new and refurbished components exceeds 75 percent of the fixed capital cost of a comparable entirely new facility. An engine that is produced from a previously used engine block does not retain the date of manufacture of the engine in which the engine block was previously used if the engine is produced using all new components except for the engine block. In these cases, the date of manufacture is the date of reconstruction or the date the new engine is produced.

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 reciprocating internal combustion engine that meets all of the criteria in paragraphs (1) through (3) of this definition. All emergency stationary ICE must comply with the requirements specified in §60.4211(f) in order to be considered emergency stationary ICE. If the engine does not comply with the requirements specified in §60.4211(f), then it is not considered to be an emergency stationary ICE under this subpart.

(1) The stationary ICE is operated to provide electrical power or mechanical work during an emergency situation. 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.

(2) The stationary ICE is operated under limited circumstances for situations not included in paragraph (1) of this definition, as specified in §60.4211(f).

(3) The stationary ICE operates as part of a financial arrangement with another entity in situations not included in paragraph (1) of this definition only as allowed in §60.4211(f)(2)(ii) or (iii) and §60.4211(f)(3)(i).

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.

Freshly manufactured engine means an engine that has not been placed into service. An engine becomes freshly manufactured when it is originally produced.

Installed means the engine is placed and secured at the location where it is intended to be operated.

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 the calendar year in which an engine is manufactured (see “date of manufacture”), except as follows:

(1) Model year means the annual new model production period of the engine manufacturer in which an engine is manufactured (see “date of manufacture”), if the annual new model production period is different than the calendar year and includes 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.

(2) 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 manufactured (see “date of manufacture”).

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, aircraft, 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.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011; 78 FR 6696, Jan. 30, 2013]

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
KW<8 (HP<11)	10.5 (7.8)			8.0 (6.0)	1.0 (0.75)
8≤KW<19 (11≤HP<25)	9.5 (7.1)			6.6 (4.9)	0.80 (0.60)
19≤KW<37 (25≤HP<50)	9.5 (7.1)			5.5 (4.1)	0.80 (0.60)
37≤KW<56 (50≤HP<75)			9.2 (6.9)		
56≤KW<75 (75≤HP<100)			9.2 (6.9)		
75≤KW<130 (100≤HP<175)			9.2 (6.9)		
130≤KW<225 (175≤HP<300)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
225≤KW<450 (300≤HP<600)		1.3 (1.0)	9.2 (6.9)	11.4 (8.5)	0.54 (0.40)
450≤KW≤560 (600≤HP≤750)		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 2 to Subpart IIII of Part 60—Emission Standards for 2008 Model Year and Later Emergency Stationary CI ICE <37 KW (50 HP) With a Displacement of <10 Liters per Cylinder

[As stated in §60.4202(a)(1), you must comply with the following emission standards]

Engine power	Emission standards for 2008 model year and later emergency stationary CI ICE <37 KW (50 HP) with a displacement of <10 liters per cylinder in g/KW-hr (g/HP-hr)			
	Model year(s)	NO_X + NMHC	CO	PM
KW<8 (HP<11)	2008+	7.5 (5.6)	8.0 (6.0)	0.40 (0.30)
8≤KW<19 (11≤HP<25)	2008+	7.5 (5.6)	6.6 (4.9)	0.40 (0.30)
19≤KW<37 (25≤HP<50)	2008+	7.5 (5.6)	5.5 (4.1)	0.30 (0.22)

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)[1]
KW<75 (HP<100)	2011
75≤KW<130 (100≤HP<175)	2010
130≤KW≤560 (175≤HP≤750)	2009
KW>560 (HP>750)	2008

[1]Manufacturers of fire pump stationary CI ICE with a maximum engine power greater than or equal to 37 kW (50 HP) and less than 450 KW (600 HP) and a rated speed of greater than 2,650 revolutions per minute (rpm) are not required to certify such engines until three model years following the model year indicated in this Table 3 for engines in the applicable engine power category.

[71 FR 39172, July 11, 2006, as amended at 76 FR 37972, June 28, 2011]

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
KW<8 (HP<11)	2010 and earlier	10.5 (7.8)	8.0 (6.0)	1.0 (0.75)
	2011+	7.5 (5.6)		0.40 (0.30)
8≤KW<19 (11≤HP<25)	2010 and earlier	9.5 (7.1)	6.6 (4.9)	0.80 (0.60)
	2011+	7.5 (5.6)		0.40 (0.30)
19≤KW<37 (25≤HP<50)	2010 and earlier	9.5 (7.1)	5.5 (4.1)	0.80 (0.60)

Maximum engine power	Model year(s)	NMHC + NO_X	CO	PM
	2011+	7.5 (5.6)		0.30 (0.22)
37≤KW<56 (50≤HP<75)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
56≤KW<75 (75≤HP<100)	2010 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2011+[1]	4.7 (3.5)		0.40 (0.30)
75≤KW<130 (100≤HP<175)	2009 and earlier	10.5 (7.8)	5.0 (3.7)	0.80 (0.60)
	2010+[2]	4.0 (3.0)		0.30 (0.22)
130≤KW<225 (175≤HP<300)	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)
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)
450≤KW≤560 (600≤HP≤750)	2008 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2009+	4.0 (3.0)		0.20 (0.15)
KW>560 (HP>750)	2007 and earlier	10.5 (7.8)	3.5 (2.6)	0.54 (0.40)
	2008+	6.4 (4.8)		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
19≤KW<56 (25≤HP<75)	2013
56≤KW<130 (75≤HP<175)	2012
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:

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 number/location of traverse points at the inlet and outlet of the control device;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Measure O_2 at the inlet and outlet of the control device;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(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	(2) Method 4 of 40 CFR part 60, appendix A-3, 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_X concentration.

Each	Complying with the requirement to	You must	Using	According to the following requirements
		iv. Measure NO_X at the inlet and outlet of the control device.	(3) Method 7E of 40 CFR part 60, appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO_X 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.
	b. Limit the concentration of NO_X in the stationary CI internal combustion engine exhaust.	i. Select the sampling port location and number/location of traverse points at the exhaust of the stationary internal combustion engine;		(a) For NO_X, O_2, and moisture measurement, ducts ≤6 inches in diameter may be sampled at a single point located at the duct centroid and ducts >6 and ≤12 inches in diameter may be sampled at 3 traverse points located at 16.7, 50.0, and 83.3% of the measurement line ('3-point long line'). If the duct is >12 inches in diameter *and* the sampling port location meets the two and half-diameter criterion of Section 11.1.1 of Method 1 of 40 CFR part 60, appendix A-1, the duct may be sampled at '3-point long line'; otherwise, conduct the stratification testing and select sampling points according to Section 8.1.2 of Method 7E of 40 CFR part 60, appendix A-4.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(1) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration must be made at the same time as the measurement for NO_X concentration.
		iii. If necessary, measure moisture content of the stationary internal combustion engine exhaust at the sampling port location; and	(2) Method 4 of 40 CFR part 60, appendix A-3, 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_X concentration.
		iv. Measure NO_X at the exhaust of the stationary internal combustion engine; if using a control device, the sampling site must be located at the outlet of the control device.	(3) Method 7E of 40 CFR part 60, Appendix A-4, Method 320 of 40 CFR part 63, appendix A, or ASTM D 6348-03 (incorporated by reference, see §60.17)	(d) NO_X 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.

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-1	(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-2	(b) Measurements to determine O_2 concentration 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-3	(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-3	(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-1	(a) If using a control device, the sampling site must be located at the outlet of the control device.
		ii. Determine the O_2 concentration of the stationary internal combustion engine exhaust at the sampling port location;	(2) Method 3, 3A, or 3B of 40 CFR part 60, appendix A-2	(b) Measurements to determine O_2 concentration 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-3	(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-3.	(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.

[79 FR 11251, Feb. 27, 2014]

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	
§60.18	General control device requirements	No	
§60.19	General notification and reporting requirements	Yes	

Attachment E.ii

Part 70 Operating Permit No: T089-30396-00453

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart Y—National Emission Standards for Marine Tank Vessel Loading Operations

Source: 60 FR 48399, Sept. 19, 1995, unless otherwise noted.

§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.

(4) Existing sources with emissions less than 10 and 25 tons must meet the submerged fill standards of 46 CFR 153.282. This submerged fill requirement does not apply to petroleum refineries.

(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).

(c) *General Provisions applicability.* Owners or operators of affected sources, as that term is defined in §63.561, of this subpart must comply with the requirements of subpart A of this part in accordance with the provisions for applicability of subpart A to this subpart in Table 1 of this section.

(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, however existing offshore loading terminals must meet the submerged fill standards of 46 CFR 153.282.

(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.* (i) A new or existing source with emissions of 10 or 25 tons, except the VMT source, and a new source with emissions less than 10 and 25 tons, except the VMT source, that has an initial startup date on or before September 20, 1999 shall comply with the provisions of this subpart pertaining to the MACT standards in §63.562(b) no later than 4 years after the effective date.

(ii) A new source with emissions of 10 or 25 tons, except the VMT source, and a new source with emissions less than 10 and 25 tons, except the VMT source, that has an initial startup date after September 20, 1999 shall comply with provisions of this subpart pertaining to the MACT standards in §63.562(b) immediately upon startup.

(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.

(iv) Existing sources with emissions less than 10 and 25 tons, and existing offshore loading terminals, shall comply with the submerged fill requirements in paragraph (a)(4) and (d)(6) of this section by April 23, 2012.

(2) *RACT standards compliance dates, except the VMT source.* (i) A source with throughput of 10 M barrels or 200 M barrels, except the VMT source, with an initial startup date on or before September 21, 1998 shall comply with §63.562(c)(1) no later than 2 years after the effective date.

(ii) A source with throughput of 10 M barrels or 200 M barrels, except the VMT source, with an initial startup date on or before September 21, 1998 shall comply with the provisions of this subpart pertaining to the RACT standards in §63.562(c) other than §63.562(c)(1), no later than 3 years after the effective date.

(iii) A source with throughput of 10 M barrels or 200 M barrels, except the VMT source, with an initial startup date after September 21, 1998 shall comply with the provisions of this subpart pertaining to the RACT standards in §63.562(c) immediately upon startup.

(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.

(3) *MACT and RACT compliance dates for the VMT source.* The VMT source, as that term is defined in §63.561, shall comply with the provisions of this subpart pertaining to the MACT and RACT standards in §63.562(d) no later than 30 months after the effective date.

Table 1 to §63.560—General Provisions Applicability to Subpart Y

Reference	Applies to affected sources in subpart Y	Comment
63.1(a)(1)	Yes	Additional terms are defined in §63.561; when overlap between subparts A and Y occurs, subpart Y takes precedence.
63.1(a)(2)	Yes	
63.1(a)(3)	Yes	
63.1(a)(4)	Yes	Subpart Y clarifies the applicability of each paragraph in subpart A to sources subject to subpart Y in this table.
.63.1(a)(5)	No	Reserved.
63.1(a)(6)	Yes	
63.1(a)(7)	Yes	
63.1(a)(8)	Yes	
63.1(a)(9)	No	Reserved.
63.1(a)(10)	Yes	
63.1(a)(11)	Yes	§63.567(a) also allows report submissions via facsimile and on electronic media.
63.1(a)(12)	Yes	
63.1(a)(13)	Yes	
63.1(a)(14)	Yes	
63.1(b)(1)	Yes	
63.1(b)(2)	Yes	
63.1(b)(3)	No	§63.560 specifies applicability.
63.1(c)(1)	Yes	Subpart Y clarifies the applicability of each paragraph in subpart A to sources subject to subpart Y in this table.
63.1(c)(2)	Yes	Subpart Y is not applicable to area sources.
63.1(c)(3)	No	Reserved.
63.1(c)(4)	Yes	
63.1(c)(5)	No	§63.560 specifies applicability.
63.1(d)	No	Reserved.
63.1(e)	Yes	
63.2	Yes	Additional terms are defined in §63.561; when overlap between subparts A and Y occurs, subpart Y takes precedence.
63.3	Yes	Other units used in subpart Y are defined in the text of subpart Y.
63.4(a)(1)	Yes	
63.4(a)(2)	Yes	
63.4(a)(3)	Yes	
63.4(a)(4)	No	Reserved.
63.4(a)(5)	Yes	

Reference	Applies to affected sources in subpart Y	Comment
63.4(b)	Yes	
63.4(c)	Yes	
63.5(a)	Yes	
63.5(b)(1)(i)	Yes	
63.5(b)(1)(ii)	No	
63.5(b)(2)	No	Reserved.
63.5(b)(3)	Yes	
63.5(b)(4)-(5)	No	
63.5(b)(6)	Yes	
63.5(c)	No	Reserved.
63.5(d)(1)(i)	No	See §63.566(b)(2).
63.5(d)(1)(ii)(A)(H)	Yes	
63.5(d)(1)(ii)(I)	No	Reserved.
63.5(d)(1)(ii)(J)	Yes	
63.5(d)(1)(iii)	Yes	
63.5(d)(2)-(4)	Yes	
63.5(e)	Yes	
63.5(f)(1)(i) and (ii)	Yes	
63.5(f)(1)(iii) and (iv)	No	
63.5(f)(2)	No	See §63.566(c).
63.6(a)(1)	Yes	
63.6(a)(2)	No	§63.560 specifies applicability.
63.6(b)(1)-(5)	No	§63.560(e) specifies compliance dates for sources.
63.6(b)(6)	No	Reserved.
63.6(b)(7)	No	§63.560(e) specifies compliance dates for sources.
63.6(c)(1)	No	§63.560(e) specifies compliance dates for sources.
63.6(c)(2)	No	
63.6(c)(3)-(4)	No	Reserved.
63.6(c)(5)	No	§63.560(e) specifies compliance dates for sources.
63.6(d)	No	Reserved.
63.6(e)	No	See §63.562(e).
63.6(f)(1)	No.	
63.6(f)(2)(i)	Yes	
63.6(f)(2)(ii)	No	
63.6(f)(2)(iii)	Yes	
63.6(f)(2)(iv)	Yes	
63.6(f)(2)(v)	No	See §63.562(e)(1).
63.6(f)(3)	Yes	
63.6(g)	Yes	
63.6(h)	No	No opacity monitoring is required under subpart Y.
63.6(i)(1)-(3)	Yes	
63.6(i)(4)(i)(A)	No	

Reference	Applies to affected sources in subpart Y	Comment
63.6(i)(4)(i)(B)	Yes	
63.6(i)(4)(ii)	No	
63.6(i)(5)-(12)	Yes	
63.6(i)(13)	No	
63.6(i)(14)	Yes	
63.6(i)(15)	No	Reserved.
63.6(i)(16)	Yes	
63.6(j)	Yes	
63.7(a)(1)	Yes	
63.7(a)(2)(i)-(iv)	No	See §63.563(b)(1).
63.7(a)(2)(v)	Yes	
63.7(a)(2)(vi)	No	
63.7(a)(2)(vii)-(viii)	No	Reserved.
63.7(a)(2)(ix)	No	
63.7(a)(3)	Yes	
63.7(b)	Yes	
63.7(c)(1)-(2)	Yes	The site-specific test plan must be submitted only if requested by the Administrator.
63.7(c)(3)(i)-(ii)(A)	Yes	
63.7(c)(3)(ii)(B)	No	See §63.565(m)(2).
63.7(c)(3)(iii)	Yes	
63.7(c)(4)	Yes	
63.7(d)	Yes	
63.7(e)(1)	No	See 63.563(b)(1). Any cross reference to 63.7(e)(1) in any other general provision incorporated by reference shall be treated as a cross-reference to 63.563(b)(1).
63.7(e)(2)-(4)	Yes.	
63.7(f)	Yes	
63.7(g)(1)	Yes	
63.7(g)(2)	No	Reserved.
63.7(g)(3)	Yes	
63.7(h)	Yes	
63.8(a)(1)-(2)	Yes	
63.8(a)(3)	No	Reserved.
63.8(a)(4)	Yes	
63.8(b)(1)	Yes	
63.8(b)(2)	No	
63.8(b)(3)	Yes	
63.8(c)(1)	No.	
63.8(c)(2)	Yes	
63.8(c)(3)	Yes	
63.8(c)(4)	No	See §63.564(a)(3).
63.8(c)(5)	No	

Reference	Applies to affected sources in subpart Y	Comment
63.8(c)(6)	Yes	See also performance specifications for continuous monitoring systems §63.564(a)(4).
63.8(c)(7)(i)(A)-(B)	Yes	See also §63.564(a)(5).
63.8(c)(7)(i)(C)	No	
63.8(c)(7)(ii)	Yes	
63.8(c)(8)	No	See §63.564(a)(5).
63.8(d)	No	See §63.562(e)(2)(iv).
63.8(e)(1)-(4)	Yes	
63.8(e)(5)(i)	Yes	
63.8(e)(5)(ii)	No	
63.8(f)(1)	Yes	
63.8(f)(2)(i)-(vii)	Yes	
63.8(f)(2)(viii)	No	
63.8(f)(2)(ix)	Yes	
63.8(f)(3)-(6)	Yes	
63.8(g)	Yes	
63.9(a)(1)	Yes	
63.9(a)(2)	Yes	
63.9(a)(3)	Yes	
63.9(a)(4)	Yes	
63.9(b)(1)(i)	Yes	
63.9(b)(1)(ii)	No	See §63.567(b)(1)
63.9(b)(1)(iii)	Yes	
63.9(b)(2)	No	See §63.567(b)(2).
63.9(b)(3)	No	See §63.567(b)(3).
63.9(b)(4)	No	See §63.567(b)(4).
63.9(b)(5)	No	See §63.567(b)(4).
63.9(c)	No	See §63.567(c).
63.9(d)	No	
63.9(e)	Yes	
63.9(f)	No	
63.9(g)(1)	Yes	
63.9(g)(2)	No	
63.9(g)(3)	Yes	
63.9(h)(1)-(3)	Yes	
63.9(h)(4)	No	Reserved.
63.9(h)(5)-(6)	Yes	
63.9(i)	Yes	
63.9(j)	Yes	
63.10(a)	Yes	
63.10(b)(1)	Yes	
63.10(b)(2)(i)-(ii)	No	See 63.567(m).
63.10(b)(2)(iii)	Yes.	

Reference	Applies to affected sources in subpart Y	Comment
63.10(b)(2)(iv)	No	
63.10(b)(2)(v)	No	
63.10(b)(2)(vi)-(xiv)	Yes	
63.10(b)(3)	No	See §63.567(j)(4).
63.10(c)(1)	Yes	
63.10(c)(2)-(4)	No	Reserved.
63.10(c)(5)	Yes	
63.10(c)(6)	No	See §63.564(a)(5).
63.10(c)(7)	No	
63.10(c)(8)	Yes	
63.10(c)(9)	No	Reserved.
63.10(c)(10)-(11)	No	See 63.567(m) for reporting malfunctions. Any cross-reference to 63.10(c)(10) or 63.10(c)(11) in any other general provision incorporated by reference shall be treated as a cross-reference to 63.567(m).
63.10(c)(12)-(13)	Yes.	
63.10(c)(14)	No	See §63.562(d)(2)(iv).
63.10(c)(15)	No	
63.10(d)(1)-(2)	Yes	
63.10(d)(3)	No	See §63.567(d).
63.10(d)(4)	Yes	
63.10(d)(5)	No	
63.(10)(e)(1)	Yes	
63.10(e)(2)(i)	Yes	
63.10(e)(2)(ii)	No	
63.10(e)(3)(i)-(v)	No	See §63.567(e)
63.10(e)(3)(vi).	Yes	
63.10(e)(3)(vii)-(viii)	No	See §63.567(e)
63.10(e)(4)	No	
63.10(f)	Yes	
63.11	Yes	
63.12-63.15	Yes	

[60 FR 48399, Sept. 19, 1995, as amended at 76 FR 22595, Apr. 21, 2011]

§63.561 Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Clean Air Act or in subpart A of this part.

Affected source means a source with emissions of 10 or 25 tons, a new source with emissions less than 10 and 25 tons, a new major source offshore loading terminal, a source with throughput of 10 M barrels or 200 M barrels, or the VMT source, that is subject to the emissions standards in §63.562.

Affirmative defense means, in the context of an enforcement proceeding, a response or a defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Air pollution control device or *control device* means a combustion device or vapor recovery device.

Ballasting operations means the introduction of ballast water into a cargo tank of a tankship or oceangoing barge.

Baseline operating parameter means a minimum or maximum value of a process parameter, established for a control device during a performance test where the control device is meeting the required emissions reduction or established as the manufacturer recommended operating parameter, that, if achieved by itself or in combination with one or more other operating parameters, determines if a control device is operating properly.

Boiler means a device that combusts any fuel and produces steam or heats water or any other heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system.

Car-seal means a seal that is placed on a device used to change the position of a valve (e.g., from open to closed) in such a way that the position of the valve cannot be changed without breaking the seal.

Combustion device means all equipment, including, but not limited to, thermal incinerators, catalytic incinerators, flares, boilers, and process heaters used for combustion or destruction of organic vapors.

Commenced means, with respect to construction of an air pollution control device, that an owner or operator has undertaken a continuous program of construction or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction.

Commodity means a distinct product that a source loads onto marine tank vessels.

Continuous means, with respect to monitoring, reading and recording (either in hard copy or computer readable form) of data values measured at least once every 15 minutes.

Crude oil means a naturally occurring mixture consisting predominantly of hydrocarbons and/or sulfur, nitrogen, and oxygen derivatives of hydrocarbons that is removed from the earth in a liquid state or is capable of being so removed.

Exceedance or *Variance* means, with respect to parametric monitoring, the operating parameter of the air pollution control device that is monitored as an indication of proper operation of the control device is outside the acceptable range or limits for the baseline parameter given in §63.563(b)(4) through (9).

Excess emissions means, with respect to emissions monitoring, the concentration of the outlet stream of the air pollution control device is outside the acceptable range or limits for the baseline concentration given in §63.563(b)(4) through (9).

Flow indicator means a device that indicates whether gas flow is present in a line or vent system.

Gasoline means any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kPa (4.0 psia) or greater, that is used as a fuel for internal combustion engines.

Impurity means HAP substances that are present in a commodity or that are produced in a process coincidentally with the primary product or commodity and that are 0.5 percent total HAP by weight or less. An impurity does not serve a useful purpose in the production or use of the primary product or commodity and is not isolated.

Leak means a reading of 10,000 parts per million volume (ppmv) or greater as methane that is determined using the test methods in Method 21, appendix A of part 60 of this chapter.

Lightering or *Lightering operation* means the offshore transfer of a bulk liquid cargo from one marine tank vessel to another vessel.

Loading berth means the loading arms, pumps, meters, shutoff valves, relief valves, and other piping and valves necessary to fill marine tank vessels. The loading berth includes those items necessary for an offshore loading terminal.

Loading cycle means the time period from the beginning of filling a single marine tank vessel until commodity flow to the marine tank vessel ceases.

Maintenance allowance means a period of time that an affected source is allowed to perform maintenance on the loading berth without controlling emissions from marine tank vessel loading operations.

Marine tank vessel loading operation means any operation under which a commodity is bulk loaded onto a marine tank vessel from a terminal, which may include the loading of multiple marine tank vessels during one loading operation. Marine tank vessel loading operations do not include refueling of marine tank vessels.

Marine vessel or *Marine tank vessel* means any tank ship or tank barge that transports liquid product such as gasoline or crude oil in bulk.

Nonvapor-tight means any marine tank vessel that does not pass the required vapor-tightness test.

Offshore loading terminal means a location that has at least one loading berth that is 0.81 km (0.5 miles) or more from the shore that is used for mooring a marine tank vessel and loading liquids from shore.

Primary fuel means the fuel that provides the principal heat input to the device. To be considered primary, the fuel must be able to sustain operation of the device without the addition of other fuels.

Process heater means a device that transfers heat liberated by burning fuel to fluids contained in tubes, including all fluids except water that are heated to produce steam.

Recovery device means an individual unit of equipment, including, but not limited to, a carbon adsorber, condenser/refrigeration unit, or absorber that is capable of and used for the purpose of removing vapors and recovering liquids or chemicals.

Routine loading means, with respect to the VMT source, marine tank vessel loading operations that occur as part of normal facility operation over a loading berth when no loading berths are inoperable due to maintenance.

Secondary fuel means any fuel other than the primary fuel. The secondary fuel provides supplementary heat in addition to the heat provided by the primary fuel and is generally fired through a burner other than the primary burner.

Source(s) means any location where at least one dock or loading berth is bulk loading onto marine tank vessels, except offshore drilling platforms and lightering operations.

Source(s) with emissions less than 10 and 25 tons means major source(s) having aggregate actual HAP emissions from marine tank vessel loading operations at all loading berths as follows:

(1) Prior to the compliance date, of less than 9.1 Mg (10 tons) of each individual HAP calculated on a 24-month annual average basis after September 19, 1997 and less than 22.7 Mg (25 tons) of all HAP combined calculated on a 24-month annual average basis after September 19, 1997, as determined by emission estimation in §63.565(l) of this subpart; and

(2) After the compliance date, of less than 9.1 Mg (10 tons) of each individual HAP calculated annually after September 20, 1999 and less than 22.7 Mg (25 tons) of all HAP combined calculated annually after September 20, 1999, as determined by emission estimation in §63.565(l) of this subpart.

Source(s) with emissions of 10 or 25 tons means major source(s) having aggregate actual HAP emissions from marine tank vessels loading operations at all loading berths as follows:

(1) Prior to the compliance date, emissions of 9.1 Mg (10 tons) or more of each individual HAP calculated on a 24-month annual average basis after September 19, 1997 or of 22.7 Mg (25 tons) or more of all HAP combined calculated on a 24-month annual average basis after September 19, 1997, as determined by emission estimation in §63.565(l); or

(2) After the compliance date, emissions of 9.1 Mg (10 tons) or more of each individual HAP calculated annually after September 20, 1999 or of 22.7 Mg (25 tons) or more of all HAP combined calculated annually after September 20, 1999, as determined by emission estimation in §63.565(l).

Source(s) with throughput less than 10 M barrels and 200 M barrels means source(s) having aggregate loading from marine tank vessel loading operations at all loading berths as follows:

(1) Prior to the compliance date, of less than 1.6 billion liters (10 million (M) barrels) of gasoline on a 24-month annual average basis and of less than 32 billion liters (200 M barrels) of crude oil on a 24-month annual average basis after September 19, 1996; and

(2) After the compliance date, of less than 1.6 billion liters (10 M barrels) of gasoline annually and of less than 32 billion liters (200 M barrels) of crude oil annually after September 21, 1998.

Source(s) with throughput of 10 M barrels or 200 M barrels means source(s) having aggregate loading from marine tank vessel loading operations at all loading berths as follows:

(1) Prior to the compliance date, of 1.6 billion liters (10 M barrels) or more of gasoline on a 24-month annual average basis or of 32 billion liters (200 M barrels) or more of crude oil on a 24-month annual average basis after September 19, 1996; or

(2) After the compliance date, of 1.6 billion liters (10 M barrels) or more of gasoline annually or of 32 billion liters (200 M barrels) or more of crude oil annually after September 21, 1998.

Terminal means all loading berths at any land or sea based structure(s) that loads liquids in bulk onto marine tank vessels.

Twenty-four-month (24-month) annual average basis means annual HAP emissions, with respect to MACT standards, or annual loading throughput, with respect to RACT standards, from marine tank vessel loading operations averaged over a 24-month period.

Valdez Marine Terminal (VMT) source means the major source that is permitted under the Trans-Alaska Pipeline Authorization Act (TAPAA) (43 U.S.C. §1651 *et seq.*). The source is located in Valdez, Alaska in Prince William Sound.

Vapor balancing system means a vapor collection system or piping system that is designed to collect organic HAP vapors displaced from marine tank vessels during marine tank vessel loading operations and that is designed to route the collected organic HAP vapors to the storage vessel from which the liquid being loaded originated or to compress collected organic HAP vapors and commingle with the raw feed of a process unit.

Vapor collection system means any equipment located at the source, i.e., at the terminal, that is not open to the atmosphere, that is composed of piping, connections, and flow inducing devices, and that is used for containing and transporting vapors displaced during the loading of marine tank vessels to a control device or for vapor balancing. This does not include the vapor collection system that is part of any marine vessel vapor collection manifold system.

Vapor-tight marine vessel means a marine tank vessel that has demonstrated within the preceding 12 months to have no leaks. A marine tank vessel loaded at less than atmospheric pressure is assumed to be vapor tight for the purpose of this standard.

Volatile organic compounds or *VOC* is as defined in 40 CFR 51.100(s) of this chapter.

[60 FR 48399, Sept. 19, 1995, as amended at 76 FR 22596, Apr. 21, 2011]

§63.562 Standards.

(a) The emissions limitations in paragraphs (b), (c), and (d) of this section apply during marine tank vessel loading operations.

(b) *MACT standards, except for the VMT source*—(1)(i) *Vapor collection system of the terminal.* The owner or operator of a new source with emissions less than 10 and 25 tons and an existing or new source with emissions of 10 or 25 tons shall equip each terminal with a vapor collection system that is designed to collect HAP vapors displaced from marine tank vessels during marine tank vessel loading operations and to prevent HAP vapors collected at one loading berth from passing through another loading berth to the atmosphere, except for those commodities exempted under §63.560(d).

(ii) *Ship-to-shore compatibility.* The owner or operator of a new source with emissions less than 10 and 25 tons and an existing or new source with emissions of 10 or 25 tons shall limit marine tank vessel loading operations to those vessels that are equipped with vapor collection equipment that is compatible with the terminal's vapor collection system, except for those commodities exempted under §63.560(d).

(iii) *Vapor tightness of marine vessels.* The owner or operator of a new source with emissions less than 10 and 25 tons and an existing or new source with emissions of 10 or 25 tons shall limit marine tank vessel loading operations to those vessels that are vapor tight and to those vessels that are connected to the vapor collection system, except for those commodities exempted under §63.560(d).

(2) *MACT standards for existing sources with emissions of 10 or 25 tons.* The owner or operator of an existing source with emissions of 10 or 25 tons, except offshore loading terminals and the VMT source, shall reduce captured HAP emissions from marine tank vessel loading operations by 97 weight-percent, as determined using methods in §63.565 (d) and (l).

(3) *MACT standards for new sources.* The owner or operator of a new source with emissions less than 10 and 25 tons or a new source with emissions of 10 or 25 tons, except offshore loading terminals and the VMT source, shall reduce HAP emissions from marine tank vessel loading operations by 98 weight-percent, as determined using methods in §63.565 (d) and (l).

(4) *MACT standards for new major source offshore loading terminals.* The owner or operator of a new major source offshore loading terminal shall reduce HAP emissions from marine tank vessel loading operations by 95 weight-percent, as determined using methods in §63.565 (d) and (l).

(5) *Prevention of carbon adsorber emissions during regeneration.* The owner or operator of a source subject to paragraph (b)(2), (3), or (4) shall prevent HAP emissions from escaping to the atmosphere from the regeneration of the carbon bed when using a carbon adsorber to control HAP emissions from marine tank vessel loading operations.

(6) *Maintenance allowance for loading berths.* The owner or operator of a source subject to paragraph (b)(2), (3) or (4), may apply for approval to the Administrator for a maintenance allowance for loading berths based on a percent of annual throughput or annual marine tank vessel loading operation time for commodities not exempted in §63.560(d). The owner or operator shall maintain records for all maintenance performed on the air pollution control equipment. The Administrator will consider the following in approving the maintenance allowance:

(i) The owner or operator expects to be in violation of the emissions standards due to maintenance;

(ii) Due to conditions beyond the reasonable control of the owner or operator, compliance with the emissions standards during maintenance would result in unreasonable economic hardship;

(iii) The economic hardship cannot be justified by the resulting air quality benefit;

(iv) The owner or operator has given due consideration to curtailing marine vessel loading operations during maintenance;

(v) During the maintenance allowance, the owner or operator will endeavor to reduce emissions from other loading berths that are controlled as well as from the loading berth the owner or operator is seeking the maintenance allowance; and

(vi) During the maintenance allowance, the owner or operator will monitor and report emissions from the loading berth to which the maintenance allowance applies.

(c) *RACT standards, except the VMT source*—(1) *Commencement of construction.* The owner or operator of a source with throughput of 10 M barrels or 200 M barrels, except the VMT source, with an initial startup date on or before September 21, 1998 shall provide the Agency no later than 2 years after the effective date with proof that it has commenced construction of its vapor collection system and air pollution control device.

(2)(i) *Vapor collection system of the terminal.* The owner or operator of a source with throughput of 10 M barrels or 200 M barrels shall equip each terminal with a vapor collection system that is designed to collect VOC vapors displaced from marine tank vessels during loading and to prevent VOC vapors collected at one loading berth from passing through another loading berth to the atmosphere, except for those commodities exempted under §63.560(d).

(ii) *Ship-to-shore compatibility.* The owner or operator of a source with throughput of 10 M barrels or 200 M barrels shall limit marine tank vessel loading operations to those vessels that are equipped with vapor collection equipment that is compatible with the terminal's vapor collection system, except for those commodities exempted under §63.560(d).

(iii) *Vapor tightness of marine vessels.* The owner or operator of a source with throughput of 10 M barrels or 200 M barrels shall limit marine tank vessel loading operations to those vessels that are vapor-tight and to those vessels that are connected to the vapor collection system, except for those commodities exempted under §63.560(d).

(3) *RACT standard for sources with throughput of 10 M or 200 M barrels, except the VMT source.* The owner or operator of a source with throughput of 10 M barrels or 200 M barrels, except the VMT source, shall reduce captured VOC emissions from marine tank vessel loading operations by 98 weight-percent when using a combustion device or reduce captured VOC emissions by 95 weight-percent when using a recovery device, as determined using methods in §63.565(d) and (l).

(4) The owner or operator of a source with throughput of 10 M barrels or 200 M barrels, except the VMT source, may meet the requirements of paragraph (c)(3) by reducing gasoline loading emissions to, at most, 1,000 ppmv outlet VOC concentration.

(5) *Prevention of carbon adsorber emissions during regeneration.* The owner or operator of a source with throughput of 10 M barrels or 200 M barrels shall prevent HAP emissions from escaping to the atmosphere from the regeneration of the carbon bed when using a carbon adsorber to control HAP emissions from marine tank vessel loading operations.

(6) *Maintenance allowance for loading berths.* The owner or operator of a source with throughput of 10 M barrels or 200 M barrels may apply for approval to the Administrator for a maintenance allowance for loading berths based on a percent of annual throughput or annual marine tank vessel loading operation time for commodities not exempted in §63.560(d). The owner or operator shall maintain records for all maintenance performed on the air pollution control equipment. The Administrator will consider the following in approving the maintenance allowance:

(i) The owner or operator expects to be in violation of the emissions standards due to maintenance;

(ii) Due to conditions beyond the reasonable control of the owner or operator, compliance with the emissions standards during maintenance would result in unreasonable economic hardship;

(iii) The economic hardship cannot be justified by the resulting air quality benefit;

(iv) The owner or operator has given due consideration to curtailing marine vessel loading operations during maintenance;

(v) During the maintenance allowance, the owner or operator will endeavor to reduce emissions from other loading berths that are controlled as well as from the loading berth the owner or operator is seeking the maintenance allowance; and

(vi) During the maintenance allowance, the owner or operator will monitor and report emissions from the loading berth to which the maintenance allowance applies.

(d) *MACT and RACT standards for the VMT source*—(1)(i) *Vapor collection system of the terminal.* The owner or operator of the VMT source shall equip each terminal subject under paragraph (d)(2) with a vapor collection system that is designed to collect HAP vapors displaced from marine tank vessels during marine tank vessel loading operations and to prevent HAP vapors collected at one loading berth from passing through another loading berth to the atmosphere, except for those commodities exempted under §63.560(d).

(ii) *Ship-to-shore compatibility.* The owner or operator of the VMT source shall limit marine tank vessel loading operations at berths subject under paragraph (d)(2) of this section to those vessels that are equipped with vapor collection equipment that is compatible with the terminal's vapor collection system, except for those commodities exempted under §63.560(d).

(iii) *Vapor tightness of marine vessels.* The owner or operator of the VMT source shall limit marine tank vessel loading operations at berths subject under paragraph (d)(2) of this section to those vessels that are vapor-tight and to those vessels that are connected to the vapor collection system, except for those commodities exempted under §63.560(d).

(2) The owner or operator of the VMT source shall reduce captured HAP and VOC emissions by 98 weight-percent, as determined using methods in §63.565(d) and (l) for loading berths subject under this paragraph according to paragraphs (d)(2)(i), (ii), (iii), and (iv):

(i) The owner or operator of the VMT source shall equip at least two loading berths and any additional berths indicated pursuant to paragraph (d)(2)(iii) with a vapor collection system and air pollution control device and shall load marine tank vessels over loading berths equipped with a vapor collection system and control device to the maximum extent practicable. The owner or operator shall equip all loading berths that will be used for routine loading after March 19, 1998 with a vapor collection system and control device if the annual average daily loading rate for all loading berths exceeds the limits in paragraphs (d)(2)(i)(A), (B), and (C) of this section.

(A) For 1995, 1,630,000 barrels per day; and

(B) For 1996, 1,546,000 barrels per day; and

(C) For 1997, 1,445,000 barrels per day.

(ii) Maximum extent practicable means that the total annual average daily loading over all loading berths not equipped with a vapor collection system and control device shall not exceed the totals in paragraphs (d)(2)(ii)(A) and (B):

(A) *Loading allowances for marine tank vessel loading operations at loading berths not equipped with control devices.* The following maximum annual average daily loading rate for routine loading at loading berths not equipped with control devices in any of the following years shall not exceed:

(*1*) For 1998, 275,000 barrels per day;

(*2*) For 1999, 205,000 barrels per day;

(*3*) For 2000, 118,000 barrels per day;

(*4*) For 2001, 39,000 barrels per day; and

(*5*) For 2002 and subsequent years, no marine tank vessel loading operations shall be performed at berths not equipped with a vapor collection system and control device, except as allowed for maintenance under paragraph (B).

(B) *Maintenance allowances for loading berths subject under paragraph (d)(2)(i).* Beginning in the year 2000, the owner or operator of the VMT source may have a maximum of 40 calendar days per calendar year use of loading berths not equipped with a vapor collection system and control device, in accordance with the limits in paragraph (d)(2)(ii)(B)(*a*), (*b*), or (*c*), to allow for maintenance of loading berths subject to paragraph (d)(2)(i). Beginning in the year 2002, the total annual average daily loading of crude oil over all loading berths not equipped with a vapor collection system and control device shall not exceed the amount stated in paragraph (d)(2)(ii)(B)(*b*). The 40 days allowed for maintenance shall be converted into a compliance measure of annual average daily loading over the loading berths not equipped with a vapor collection system and control device as follows:

(*1*) If the total annual average daily volume of crude oil loaded at the facility was greater than or equal to 1,100,000 barrels per day in the prior calendar year, the maintenance allowance shall not exceed an annual average daily loading of 60,000 barrels per day.

(*2*) If the total annual average daily volume of crude oil loaded at the facility was less than 1,100,000 barrels per day and greater than or equal to 550,000 barrels per day in the prior calendar year, the maintenance allowance for the calendar year shall not exceed Q_m:

$$Q_m = \frac{(P - 550,000) \times 40}{365}$$

Where:

Q_m = maintenance allowance, barrels per day

P = prior calendar year's average daily volume of crude oil loaded at the facility, barrels per day.

(*3*) If the total annual average daily volume of crude oil loaded at the facility was less than 550,000 barrels per day in the prior calendar year, there shall be no maintenance allowance.

(iii) If the average daily loading rate for the loading berths not equipped with a vapor collection system and control device is greater than the combined amounts in any year listed in paragraphs (d)(2)(i)(A), (B), and (C) and (d)(2)(ii)(A) and (B), then the owner or operator of the VMT source shall equip all loading berths used for routine loading with a vapor collection system and control device within 2 years of the exceedance except that in an emergency situation the Administrator may, instead of requiring controls, approve an alternative plan to reduce loading over the unequipped berth(s) to a level which will ensure compliance with the applicable limit. Beginning in the year 2002, the owner or operator of the VMT source shall equip all uncontrolled loading berths used for marine tank vessel loading operations beyond the maintenance allowance in paragraph (d)(2)(ii)(B) with a vapor collection system and control device.

(iv) The owner or operator of the VMT source shall develop a program to communicate to relevant facility operations and marine transportation personnel and engage their active and consistent participation in honoring the intent and goal of minimizing loaded volumes over the unequipped berths and maximizing the loaded volumes at the berths equipped with a vapor collection system and control device to prevent exceedance of the load volume limits in paragraphs (d)(2)(ii)(A) and (B). This program is to be presented semi-annually during the first year of compliance and annually thereafter until the use of unequipped berths for routine loading is no longer required.

(e) Operation and maintenance requirements for air pollution control equipment and monitoring equipment for affected sources. At all times, owners or operators of affected sources shall operate and maintain a source, including associated air pollution control equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether acceptable operation and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(1) The Administrator will determine compliance with design, equipment, work practice, or operational emission standards by evaluating an owner or operator's conformance with operation and maintenance requirements.

(2) The owner or operator of an affected source shall develop a written operation and maintenance plan that describes in detail a program of corrective action for varying (i.e., exceeding baseline parameters) air pollution control equipment and monitoring equipment, based on monitoring requirements in §63.564, used to comply with these emissions standards. The plan shall also identify all routine or otherwise predictable continuous monitoring system (thermocouples, pressure transducers, continuous emissions monitors (CEMS), etc.) variances.

(i) The plan shall specify procedures (preventive maintenance) to be followed to ensure that pollution control equipment and monitoring equipment functions properly and variances of the control equipment and monitoring equipment are minimal.

(ii) The plan shall identify all operating parameters to be monitored and recorded for the air pollution control device as indicators of proper operation and shall establish the frequency at which the parameters will be monitored (see §63.564).

(iii) Owners or operators of affected sources shall incorporate a standardized inspection schedule for each component of the control device used to comply with the emissions standards in §63.562(b), (c), and (d). To satisfy the requirements of this paragraph, the owner or operator may use the inspection schedule recommended by the vendor of the control system or any other technical publication regarding the operation of the control system.

(iv) Owners or operators shall develop and implement a continuous monitoring system (CMS) quality control program. The owner or operator shall develop and submit to the Administrator for approval upon request a site-specific performance evaluation test plan for the CMS performance evaluation required in §63.8(e) of subpart A of this part. Each quality control program shall include, at a minimum, a written protocol that describes procedures for initial and any subsequent calibration of the CMS; determination and adjustment of the calibration drift of the CMS; preventive maintenance of the CMS, including spare parts inventory; data recording, calculations, and reporting; and accuracy audit procedures, including sampling and analysis methods. The owner or operation shall maintain records of the procedures that are part of the quality control program developed and implemented for CMS.

(3) Based on the results of the determination made under paragraph (e)(2), the Administrator may require that an owner or operator of an affected source make changes to the operation and maintenance plan for that source. Revisions may be required if the plan:

(i) Does not address a variance of the air pollution control equipment or monitoring equipment that has occurred that increases emissions;

(ii) Fails to provide for operation during a variance of the air pollution control equipment or the monitoring equipment in a manner consistent with safety and good air pollution control practices; or

(iii) Does not provide adequate procedures for correcting a variance of the air pollution control equipment or monitoring equipment as soon as reasonable.

(4) If the operation and maintenance plan fails to address or inadequately addresses a variance event at the time the plan was initially developed, the owner or operator shall revise the operation and maintenance plan within 45 working days after such an event occurs. The revised plan shall include procedures for operating and maintaining the air pollution control equipment or monitoring equipment during similar variance events and a program for corrective action for such events.

(5) The operation and maintenance plan shall be developed by the source's compliance date. The owner or operator shall keep the written operation and maintenance plan on record to be made available for inspection, upon request, by the Administrator for the life of the source. In addition, if the operation and maintenance plan is revised, the owner or operator shall keep previous (i.e., superseded) versions of the plan on record to be made available for inspection upon request by the Administrator for a period of 5 years after each revision to the plan.

(6) To satisfy the requirements of the operation and maintenance plan, the owner or operator may use the source's standard operating procedures (SOP) manual, an Occupational Safety and Health Administration (OSHA) plan, or

other existing plans provided the alternative plans meet the requirements of this section and are made available for inspection when requested by the Administrator.

(7) In response to an action to enforce the standards set forth in this subpart, you may assert an affirmative defense to a claim for civil penalties for exceedances of such standards that are caused by a malfunction, as defined in §63.2. Appropriate penalties may be assessed, however, if the respondent fails to meet its burden of proving all the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(i) To establish the affirmative defense in any action to enforce such a limit, the owners or operators of a facility must timely meet the notification requirements of paragraph (e)(7)(ii) of this section, and must prove by a preponderance of evidence that:

(A) The excess emissions were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, or a process to operate in a normal and usual manner; and could not have been prevented through careful planning, proper design or better operation and maintenance practices; and did not stem from any activity or event that could have been foreseen and avoided, or planned for; and were not part of a recurring pattern indicative of inadequate design, operation, or maintenance;

(B) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs;

(C) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions;

(D) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage;

(E) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment, and human health;

(F) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices;

(G) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs;

(H) At all times, the affected facility was operated in a manner consistent with good practices for minimizing emissions; and

(I) The owner or operator has prepared a written root cause analysis, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using the best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(ii) *Notification.* The owner or operator of the facility experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in this subpart to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (e)(7)(i) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

[60 FR 48399, Sept. 19, 1995, as amended at 68 FR 37350, June 23, 2003; 71 FR 20457, Apr. 20, 2006; 76 FR 22596, Apr. 21, 2011]

§63.563 Compliance and performance testing.

(a) The following procedures shall be used to determine compliance with the emissions limits under §63.562(b)(1), (c)(2), and (d)(1):

(1) *Vent stream by-pass requirements for the terminal's vapor collection system.* (i) In accordance with §63.562(b)(1)(i), (c)(2)(i), and (d)(1)(i), each valve in the terminal's vapor collection system that would route displaced vapors to the atmosphere, either directly or indirectly, shall be secured closed during marine tank vessel loading operations either by using a car-seal or a lock-and-key type configuration, or the by-pass line from the valve shall be equipped with a flow indicator, except for those valves used for pressure/vacuum relief, analyzers, instrumentation devices, sampling, and venting for maintenance. Marine tank vessel loading operations shall not be performed with open by-pass lines.

(ii) Repairs shall be made to valves, car-seals, or closure mechanisms no later than 15 days after a change in the position of the valve or a break in the car-seal or closure mechanism is detected or no later than prior to the next marine tank vessel loading operation, whichever is later.

(2) *Ship-to-shore compatibility of vapor collection systems.* Following the date on which the initial performance test is completed, marine tank vessel loading operations must be performed only if the marine tank vessel's vapor collection equipment is compatible to the terminal's vapor collection system; marine tank vessel loading operations must be performed only when the marine tank vessel's vapor collection equipment is connected to the terminal's vapor collection system, as required in §63.562(b)(1)(ii), (c)(2)(ii), and (d)(1)(ii).

(3) *Pressure/vacuum settings for the marine tank vessel's vapor collection equipment.* During the initial performance test required in paragraph (b)(1) of this section, the owner or operator of an affected source shall demonstrate compliance with operating pressure requirements of 33 CFR 154.814 using the procedures in §63.565(b).

(4) *Vapor-tightness requirements of the marine vessel.* The owner or operator of an affected source shall use the procedures in paragraph (a)(4)(i), (ii), (iii), or (iv) of this section to ensure that marine tank vessels are vapor tight, as required in §63.562(b)(1)(iii), (c)(2)(iii), and (d)(1)(iii).

(i) *Pressure test documentation for determining vapor tightness of the marine vessel.* The owner or operator of a marine tank vessel, who loads commodities containing HAP not determined to be exempt under §63.560(d) at an affected source, shall provide a copy of the vapor-tightness pressure test documentation described in §63.567(i) for each marine tank vessel prior to loading. The date of the test listed in the documentation must be within the preceding 12 months, and the test must be conducted in accordance with the procedures in §63.565(c)(1). Following the date on which the initial performance test is completed, the affected source must check vapor-tightness pressure test documentation for marine tank vessels loaded at positive pressure.

(ii) *Leak test documentation for determining vapor tightness of the marine vessel.* If no documentation of the vapor tightness pressure test as described in paragraph (a)(4)(i) of this section is available, the owner or operator of a marine tank vessel, who loads commodities containing HAP not determined to be exempt under §63.560(d) at an affected source, shall provide the leak test documentation described in §63.567(i) for each marine tank vessel prior to loading. The date of the test listed in the documentation must be within the preceding 12 months, and the test must be conducted in accordance with the procedures in §63.565(c)(2). If the marine tank vessel has failed its most recent vapor-tightness leak test at that terminal, the owner or operator of the non-vapor-tight marine tank vessel shall provide documentation that the leaks detected during the previous vapor-tightness test have been repaired and documented with a successful vapor-tightness leak test described in §63.565(c)(2) conducted during loading. If the owner or operator of the marine tank vessel can document that repair is technically infeasible without cleaning and gas freeing or dry-docking the vessel, the owner or operator of the affected source may load the marine tank vessel. Following the date on which the initial performance test is completed, an affected source must check the vapor-tightness leak test documentation for marine tank vessels loaded at positive pressure.

(iii) *Leak test performed during loading using Method 21 for determining vapor tightness of the marine vessel.* If no documentation of vapor tightness as described in paragraphs (a)(4)(i) or (ii) of this section is available, the owner or operator of a marine tank vessel, who loads commodities containing HAP not determined to be exempt under §63.560(d) at an affected source, shall perform a leak test of the marine tank vessel during marine tank vessel loading operation using the procedures described in §63.565(c)(2).

(A) If no leak is detected, the owner or operator of a marine tank vessel shall complete the documentation described in §63.567(i) prior to departure of the vessel.

(B) If a leak is detected, the owner or operator of the marine tank vessel shall document the vapor-tightness failure for the marine tank vessel prior to departure of the vessel. The leaking component shall be repaired prior to the next marine tank vessel loading operation at a controlled terminal unless the repair is technically infeasible without cleaning and gas freeing or dry-docking the vessel. If the owner or operator of the vessel provides documentation that repair of such equipment is technically infeasible without cleaning and gas freeing or dry-docking the vessel, the equipment responsible for the leak will be excluded from future Method 21 tests until repairs are effected. A copy of this documentation shall be maintained by the owner or operator of the affected source. Repair of the equipment responsible for the leak shall occur the next time the vessel is cleaned and gas freed or dry-docked. For repairs that are technically feasible without dry-docking the vessel, the owner or operator of the affected source shall not load the vessel again unless the marine tank vessel owner or operator can document that the equipment responsible for the leak has been repaired.

(iv) *Negative pressure loading.* The owner or operator of an affected source shall ensure that a marine tank vessel is loaded with the product tank below atmospheric pressure (i.e., at negative gauge pressure). The pressure shall be measured between the facility's vapor connection and its manual isolation valve, and the measured pressure must be below atmospheric pressure. Following the date on which the initial performance test is completed, marine tank vessel loading operations for nonvapor-tight vessels must be performed below atmospheric pressure (i.e., at negative gauge pressure) in the product tank.

(b) *Compliance determination for affected sources.* The following procedures shall be used to determine compliance with the emissions limits under §63.562(b), (c), and (d).

(1) *Initial performance test.* An initial performance test shall be conducted using the procedures listed in §63.7 of subpart A of this part according to the applicability in Table 1 of §63.560, the procedures listed in this section, and the test methods listed in §63.565. The initial performance test shall be conducted within 180 days after the compliance date for the specific affected source. During this performance test, sources subject to MACT standards under §63.562(b)(2), (3), (4), and (5), and (d)(2) shall determine the reduction of HAP emissions, as VOC, for all combustion or recovery devices other than flares. Performance tests shall be conducted under such conditions as the Administrator specifies to the owner or operator based on representative performance of the affected source for the period being tested. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests. Sources subject to RACT standards under §63.562(c)(3), (4), and (5), and (d)(2) shall determine the reduction of VOC emissions for all combustion or recovery devices other than flares.

(2) *Performance test exemptions.* An initial performance test required in this section and in §63.565(d) and the continuous monitoring in §63.564(e) is not required in the following cases:

(i) When a boiler or process heater with a design heat input capacity of 44 Megawatts or less is used to comply with §63.562(b)(2), (3), or (4), (c)(3) or (4), or (d)(2) and the vent stream is used as the primary fuel or with the primary fuel;

(ii) When a boiler or process heater with a design heat input capacity of 44 Megawatts or greater is used to comply with §63.562(b)(2), (3) or (4), (c)(3) or (4), or (d)(2); or

(iii) When a boiler subject to 40 CFR part 266, subpart H, “Hazardous Waste Burned in Industrial Furnaces,” that has demonstrated 99.99 percent destruction or recovery efficiency is used to comply with §63.562(b)(2), (3), or (4), (c)(3) or (4), or (d)(2).

(3) *Operation and maintenance inspections.* If the 3-hour or 3-cycle block average operating parameters in paragraphs (b)(4) through (9) of this section, outside the acceptable operating ranges, are measured and recorded, i.e., variances of the pollution control device or monitoring equipment, the owner or operator of the affected source shall perform an unscheduled inspection of the control device and monitoring equipment and review of the parameter monitoring data. The owner or operator of the affected source shall perform an inspection and review when total parameter variance time for the control device is greater than 10 percent of the operating time for marine tank vessel loading operations on a 30-day, rolling-average basis. The inspection and review shall be conducted within 24 hours after passing the allowable variance time of 10 percent. The inspection checklist from the requirements of

§63.562(e)(2)(iii) and the monitoring data from requirements in §§63.562(e)(2)(ii) and 63.564 should be used to identify any maintenance problems that may be associated with the variance. The unscheduled inspection should encompass all components of the control device and monitoring equipment that can be inspected while in operation. If any maintenance problem is identified during the inspection, the owner or operator of the affected source must take corrective action (e.g., adjustments to operating controls, etc.) as soon as practicable. If no immediate maintenance problems are identified from the inspection performed while the equipment is operating, a complete inspection in accordance with §63.562(e)(2) must be conducted prior to the next marine tank vessel loading operation and corrective action (e.g., replacement of defective parts) must be taken as soon as practicable for any maintenance problem identified during the complete inspection.

(4) *Combustion device, except flare.* During the initial performance test required in paragraph (b)(1) of this section, the owner or operator shall determine the efficiency of and/or the outlet VOC concentration from the combustion device used to comply with §63.562(b)(2), (3), and (4), (c)(3) and (4), and (d)(2) using the test methods in §63.565(d). The owner or operator shall comply with paragraph (b)(4)(i) or (ii) of this section.

(i) *Outlet VOC concentration limit for required percent combustion efficiency.* The owner or operator shall establish as an operating parameter the baseline VOC concentration using the procedures described in §63.565(g). Following the date on which the initial performance test is completed, the facility shall be operated with a block average outlet VOC concentration as determined in §63.564(e)(1) no more than 20 percent above the baseline VOC concentration.

(ii) *Baseline temperature for required percent combustion efficiency.* The owner or operator shall establish as an operating parameter the baseline temperature using the procedures described in §63.565(f). Following the date on which the initial performance test is completed, the facility shall be operated with the block average temperature as determined in §63.564(e)(2) or (3) no more than 28 °C (50 °F) below the baseline temperature.

(5) *Flare.* During the initial performance test required in paragraph (b)(1) of this section, the owner or operator shall establish that the flare used to comply with the emissions standards in §63.562(b)(2), (3), and (4), (c)(3) and (4), and (d)(2) is in compliance with the design requirements for flares cited in §63.565(e). Following the date on which the initial determination of compliance is established, the facility shall operate with the presence of a pilot flame in the flare, as determined in §63.564(f).

(6) *Carbon adsorber.* During the initial performance test required in paragraph (b)(1) of this section, the owner or operator shall determine the efficiency of and/or the outlet VOC concentration from the recovery device used to comply with §63.562(b)(2), (3), (4), and (5), (c)(3), (4), and (5), and (d)(2) using the test methods in §63.565(d). The owner or operator shall comply with paragraph (b)(6)(i) as well as either paragraph (b)(6)(ii) or (iii) of this section. The owner or operator of affected sources complying with paragraph (b)(6)(ii)(B) or (C) of this section shall conduct a performance test once each year.

(i) *Compliance determination for carbon bed regeneration.* Desorbed hydrocarbons from regeneration of the off-line carbon bed shall be vented to the on-line carbon bed.

(ii) *Baseline parameters for required percent recovery efficiency.* The owner or operator shall comply with paragraph (b)(6)(ii)(A), (B), or (C) of this section.

(A) *Outlet VOC concentration limit for required percent recovery efficiency.* The owner or operator shall establish as an operating parameter the baseline VOC concentration using the procedures described in §63.565(g). Following the date on which the initial performance test is completed, the facility shall be operated with a block average outlet VOC concentration as determined in §63.564(g)(1) no more than 20 percent above the baseline VOC concentration.

(B) *Carbon adsorbers with vacuum regeneration.* The owner or operator shall establish as operating parameters the baseline regeneration time for the vacuum stage of carbon bed regeneration using the procedures described in §63.565(h) and shall establish the baseline vacuum pressure (negative gauge pressure) using the procedures described in §63.565(i). Following the date on which the initial performance test is completed, the facility shall be operated with block average regeneration time of the vacuum stage of carbon bed regeneration as determined in §63.564(g)(2) no more than 20 percent below the baseline regeneration time, and the facility shall be operated with the block average vacuum pressure (negative gauge pressure) as determined in §63.564(g)(2) no more than 20 percent above the baseline vacuum pressure.

(C) *Carbon adsorbers with steam regeneration.* The owner or operator shall establish as operating parameters the baseline total stream flow using the procedures described in §63.565(j) and a baseline carbon bed temperature after cooling of the bed using the procedures in §63.565(f)(2). Following the date on which the initial performance test is completed, the facility shall be operated with the total stream flow, as determined in §63.564(g)(3), no more than 20 percent below the baseline stream flow and with the carbon bed temperature (measured within 15 minutes after completion of the cooling cycle), as determined in §63.564(g)(3), no more than 10 percent or 5.6 °C (10 °F) above the baseline carbon bed temperature, whichever is less stringent.

(iii) *Outlet VOC concentration of 1,000 ppmv for gasoline loading.* Following the date on which the initial performance test is completed, the facility shall operate with a block average outlet VOC concentration as determined in §63.564(g)(1) of no more than 1,200 ppmv VOC.

(7) *Condenser/refrigeration unit.* During the initial performance test required in paragraph (b)(1) of this section, the owner or operator shall determine the efficiency of and/or the outlet VOC concentration from the recovery device used to comply with §63.562(b)(2), (3), and (4), (c)(3) and (4), and (d)(2) using the test methods in §63.565(d). The owner or operator shall comply with either paragraph (b)(7)(i), (ii), or (iii) of this section.

(i) *VOC outlet concentration limit for required percent recovery efficiency.* The owner or operator shall establish as an operating parameter the baseline VOC concentration using the procedures described in §63.565(g). Following the date on which the initial performance test is completed, the facility shall be operated with a block average outlet VOC concentration as determined in §63.564(h)(2) no more than 20 percent above the baseline VOC concentration.

(ii) *Baseline temperature for required percent recovery efficiency.* The owner or operator shall establish as an operating parameter the baseline temperature using the procedures described in §63.565(f). Following the date on which the initial performance test is completed, the facility shall operate with a block average temperature, as determined in §63.564(h)(1), no more than 28 °C (50 °F) above the baseline temperature.

(iii) *Baseline parameters for 1,000 ppmv VOC concentration limit for gasoline loading.* The owner or operator shall monitor either the outlet VOC concentration or the outlet temperature of the unit. For sources monitoring temperature, the owner or operator shall establish as an operating parameter the baseline temperature using the procedures described in §63.565(f). Following the date on which the initial performance test is completed, the facility shall operate with a block average outlet VOC concentration, as determined in §63.564(h)(2), of no more than 1,200 ppmv VOC or with a block average temperature, as determined in §63.564(h)(1), no more than 28 °C (50 °F) above the baseline temperature.

(8) *Absorber.* During the initial performance test required in paragraph (b)(1) of this section, the owner or operator shall determine the efficiency of the absorber and/or the outlet VOC concentration from the recovery device used to comply with §63.562(b)(2), (3), and (4), (c)(3) and (4), and (d)(2) using the test methods in §63.565(d). The owner or operator shall comply with either paragraph (b)(8)(i) or (ii) of this section.

(i) *VOC outlet concentration limit for required percent recovery efficiency.* The owner or operator shall establish as an operating parameter the baseline VOC concentration using the procedures described in §63.565(g). Following the date on which the initial performance test is completed, the facility shall be operated with a block average outlet VOC concentration as determined in §63.564(i)(1) no more than 20 percent above the baseline VOC concentration.

(ii) *Baseline liquid-to-vapor ratio for required percent recovery efficiency.* The owner or operator shall establish as an operating parameter the baseline liquid flow to vapor flow (L/V) ratio using the procedures described in §63.565(k). Following the date on which the initial performance test is completed, the facility shall operate with a block average L/V ratio, as determined in §63.564(i)(2), no more than 20 percent below the baseline L/V ratio.

(9) *Alternative control devices.* For sources complying with §63.562(b)(2), (3), and (4), (c)(3) and (4), and (d)(2) with the use of a control technology other than the devices discussed in paragraphs (b)(4) through (8) of this section, the owner or operator of an affected source shall provide to the Administrator information describing the design and operation of the air pollution control system, including recommendations for the operating parameter(s) to be monitored to indicate proper operation and maintenance of the air pollution control system. Based on this information, the Administrator shall determine the operating parameter(s) to be established during the performance test. During the initial performance test required in paragraph (b)(1) of this section, the owner or operator shall determine the efficiency of the air pollution control system using the test methods in §63.565(d). The device shall achieve at least the percent destruction efficiency or recovery efficiency required under §63.562(b)(2), (3), and (4), (c)(3) and (4), and

(d)(2). The owner or operator shall establish the operating parameter(s) approved by the Administrator. Following the date on which the initial performance test is complete, the facility shall operate either above or below a maximum or minimum operating parameter, as appropriate.

(10) *Emission estimation.* The owner or operator of a source subject to §63.562(b)(2), (3), and (4) shall use the emission estimation procedures in §63.565(l) to calculate HAP emissions.

(c) *Leak detection and repair for vapor collection systems and control devices.* The following procedures are required for all sources subject to §63.562(b), (c), or (d).

(1) *Annual leak detection and repair for vapor collection systems and control devices.* The owner or operator of an affected source shall inspect and monitor all ductwork and piping and connections to vapor collection systems and control devices once each calendar year using Method 21.

(2) *Ongoing leak detection and repair for vapor collection systems and control devices.* If evidence of a potential leak is found by visual, audible, olfactory, or any other detection method, all ductwork and piping and connections to vapor collection systems and control devices shall be inspected to the extent necessary to positively identify the potential leak and any potential leaks shall be monitored within 5 days by Method 21. Each detection of a leak shall be recorded, and the leak shall be tagged until repaired.

(3) When a leak is detected, a first effort to repair the vapor collection system and control device shall be made within 15 days or prior to the next marine tank vessel loading operation, whichever is later.

[60 FR 48399, Sept. 19, 1995, as amended at 76 FR 22597, Apr. 21, 2011]

§63.564 Monitoring requirements.

(a)(1) The owner or operator of an affected source shall comply with the monitoring requirements in §63.8 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 the monitoring requirements in this section.

(2) Each owner or operator of an affected source shall monitor the parameters specified in this section. All monitoring equipment shall be installed such that representative measurements of emissions or process parameters from the source are obtained. For monitoring equipment purchased from a vendor, verification of the operational status of the monitoring equipment shall include completion of the manufacturer's written specifications or recommendations for installation, operation, and calibration of the system.

(3) Except for system breakdowns, out-of-control periods, repairs, maintenance periods, calibration checks, and zero (low-level) and high-level calibration drift adjustments, all continuous parametric monitoring systems (CPMS) and CEMS shall be in continuous operation while marine tank vessel loading operations are occuring and shall meet minimum frequency of operation requirements. Sources monitoring by use of CEMS and CPMS shall complete a minimum of one cycle of operation (sampling, analyzing, and/or data recording) for each successive 15-minute period.

(4) The owner or operator of a CMS installed in accordance with these emissions standards shall comply with the performance specifications either in performance specification (PS) 8 in 40 CFR part 60, appendix B for CEMS or in §63.7(c)(6) of subpart A of this part for CPMS.

(5) A CEMS is out of control when the measured values (i.e., daily calibrations, multipoint calibrations, and performance audits) exceed the limits specified in either PS 8 or in §63.8(c)(7) of subpart A of this part. The owner or operator of a CEMS that is out of control shall submit all information concerning out of control periods, including start and end dates and hours and descriptions of corrective actions taken, in the excess emissions and continuous monitoring system performance report required in §63.567(e).

(b) *Vapor collection system of terminal.* Owners or operators of a source complying with §63.563(a)(1) that uses a vapor collection system that contains valves that could divert a vent stream from a control device used to comply with the provisions of this subpart shall comply with paragraph (b)(1), (2), or (3) of this section.

(1) Measure and record the vent stream flowrate of each by-pass line once every 15 minutes. The owner or operator shall install, calibrate, maintain, and operate a flow indicator and data recorder. The flow indicator shall be installed immediately downstream of any valve (i.e., entrance to by-pass line) that could divert the vent stream from the control device to the atmosphere.

(2) Measure the vent stream flowrate of each by-pass line once every 15 minutes. The owner or operator shall install, calibrate, maintain, and operate a flow indicator with either an audio or visual alarm. The flow indicator and alarm shall be installed immediately downstream of any valve (i.e., entrance to by-pass line) that could divert the vent stream from the control device to the atmosphere. The alarm shall be checked every 6 months to demonstrate that it is functioning properly.

(3) Visually inspect the seal or closure mechanism once during each marine tank vessel loading operation and at least once every month to ensure that the valve is maintained in the closed position and that the vent stream is not diverted through the by-pass line; record all times when the car seals have been broken and the valve position has been changed. Each by-pass line valve shall be secured in the closed position with a car-seal or a lock-and-key type configuration.

(c) *Pressure/vacuum settings for the marine tank vessel's vapor collection equipment.* Owners or operators of a source complying with §63.563(a)(3) shall measure continuously the operating pressure of the marine tank vessel during loading.

(d) *Loading at negative pressure.* Owners or operators of a source complying with §63.563(a)(4)(iv) that load vessels at less than atmospheric pressure (i.e., negative gauge pressure) shall measure and record the loading pressure. The owner or operator shall install, calibrate, maintain, and operate a recording pressure measurement device (magnehelic gauge or equivalent device) and an audible and visible alarm system that is activated when the pressure vacuum specified in §63.563(a)(4)(iv) is not attained. The owner or operator shall place the alarm system so that it can be seen and heard where cargo transfer is controlled. The owner or operator shall verify the accuracy of the pressure device once each calendar year with a reference pressure monitor (traceable to National Institute of Standards and Technology (NIST) standards or an independent pressure measurement device dedicated for this purpose).

(e) *Combustion device, except flare.* For sources complying with §63.563(b)(4), use of a combustion device except a flare, the owner or operator shall comply with paragraph (e)(1), (2), or (3) of this section. Owners or operators complying with paragraphs (e)(2) or (3) shall also comply with paragraph (e)(4) of this section.

(1) *Outlet VOC concentration.* Monitor the VOC concentrations at the exhaust point of the combustion device and record the output from the system. For sources monitoring the outlet VOC concentration established during the performance test, a data acquisition system shall record a concentration every 15 minutes and shall compute and record an average concentration each cycle (same time period or cycle as the performance test) and a 3-cycle block average concentration every third cycle. For sources monitoring the 1,000 ppmv VOC concentration for gasoline loading, a data acquisition system shall record a concentration every 15 minutes and shall compute and record an average concentration each hour and a 3-hour block average concentration every third hour. The owner or operator will install, calibrate, operate, and maintain a CEMS consistent with the requirements of PS 8 to measure the VOC concentration. The daily calibration requirements are required only on days when marine tank vessel loading operations occur.

(2) *Operating temperature determined during performance testing.* If the baseline temperature was established during the performance test, the data acquisition system shall record the temperature every 15 minutes and shall compute and record an average temperature each cycle (same time period or cycle of the performance test) and a 3-cycle block average every third cycle.

(3) *Manufacturer's recommended operating temperature.* If the baseline temperature is based on the manufacturer recommended operating temperature, the data acquisition system shall record the temperature every 15 minutes and shall compute and record an average temperature each hour and a 3-hour block average every third hour.

(4) *Temperature monitor.* The owner or operator shall install, calibrate, operate, and maintain a temperature monitor accurate to within ±5.6 °C (±10 °F) or within 1 percent of the baseline temperature, whichever is less stringent, to measure the temperature. The monitor shall be installed at the exhaust point of the combustion device but not within the combustion zone. The owner or operator shall verify the accuracy of the temperature monitor once each calendar

year with a reference temperature monitor (traceable to National Institute of Standards and Technology (NIST) standards or an independent temperature measurement device dedicated for this purpose). During accuracy checking, the probe of the reference device shall be at the same location as that of the temperature monitor being tested.

(f) *Flare.* For sources complying with §63.563(b)(5), use of a flare, the owner or operator shall monitor and record continuously the presence of the flare pilot flame. The owner or operator shall install, calibrate, maintain, and operate a heat sensing device (an ultraviolet beam sensor or thermocouple) at the pilot light to indicate the presence of a flame during the entire loading cycle.

(g) *Carbon adsorber.* For sources complying with §63.563(b)(6), use of a carbon adsorber, the owner or operator shall comply with paragraph (g)(1), (2), or (3) of this section.

(1) *Outlet VOC concentration.* Monitor the VOC concentrations at the exhaust point of each carbon adsorber unit and record the output from the system. For sources monitoring the outlet VOC concentration established during the performance test, a data acquisition system shall record a concentration every 15 minutes and shall compute and record an average concentration each cycle (same time period or cycle as the performance test) and a 3-cycle block average concentration every third cycle. For sources monitoring the 1,000 ppmv VOC concentration for gasoline loading, a data acquisition system shall record a concentration every 15 minutes and shall compute and record an average concentration each hour and a 3-hour block average concentration every third hour. The owner or operator will install, calibrate, operate, and maintain a CEMS consistent with the requirements of PS 8 to measure the VOC concentration. The daily calibration requirements are required only on days when marine tank vessel loading operations occur.

(2) *Carbon adsorbers with vacuum regeneration.* Monitor and record the regeneration time for carbon bed regeneration and monitor and record continuously the vacuum pressure of the carbon bed regeneration cycle. The owner or operator will record the time when the carbon bed regeneration cycle begins and when the cycle ends for a single carbon bed and will calculate a 3-cycle block average every third cycle. The owner or operator shall install, calibrate, maintain, and operate a recording pressure measurement device (magnehelic gauge or equivalent device). A data acquisition system shall record and compute a 3-cycle (carbon bed regeneration cycle) block average vacuum pressure every third cycle. The owner or operator shall verify the accuracy of the pressure device once each calendar year with a reference pressure monitor (traceable to National Institute of Standards and Technology (NIST) standards or an independent pressure measurement device dedicated for this purpose). During accuracy checking, the probe of the reference device shall be at the same location as that of the pressure monitor being tested.

(3) *Carbon adsorbers with steam regeneration.* Monitor and record the total stream mass flow and monitor and record the carbon bed temperature after regeneration (but within 15 minutes of completion of the cooling cycle). The owner or operator will install, calibrate, maintain, and operate an integrating stream flow monitoring device that is accurate within ±10 percent and that is capable of recording the total stream mass flow for each regeneration cycle. The owner or operator will install, calibrate, maintain, and operate a temperature monitor accurate to within ±5.6 °C (10 °F) or within 1 percent of the baseline carbon bed temperature, whichever is less stringent, to measure the carbon bed temperature. The monitor shall be installed at the exhaust point of the carbon bed. The data acquisition system shall record the carbon bed temperature after each cooling cycle (measured within 15 minutes of completion of the cooling cycle). The owner or operator shall verify the accuracy of the temperature monitor once each calendar year with a reference temperature monitor (traceable to National Institute of Standards and Technology (NIST) standards or an independent temperature measurement device dedicated for this purpose). During accuracy checking, the probe of the reference device shall be at the same location as that of the temperature monitor being tested.

(h) *Condenser/refrigeration unit.* For sources complying with §63.563(b)(7), use of a condenser/refrigeration unit, the owner or operator shall comply with either paragraph (h)(1) or (2) of this section.

(1) *Baseline temperature.* Monitor and record the temperature at the outlet of the unit. The owner or operator shall install, calibrate, operate, and maintain a temperature monitor accurate to within ±5.6 °C (±10 °F) or within 1 percent of the baseline temperature, whichever is less stringent, to measure the temperature. The monitor shall be installed at the exhaust point of the condenser/refrigeration unit. For sources monitoring the temperature established during the performance test, the data acquisition system shall record the temperature every 15 minutes and shall compute and record an average temperature each cycle (same time period or cycle of the performance test) and a 3-hour block average every third cycle. For sources monitoring the manufacturer recommended temperature, the data acquisition system shall record the temperature every 15 minutes and shall compute and record an average temperature each hour and a 3-hour block average every third hour. The owner or operator shall verify the accuracy of the temperature

monitor once each calendar year with a reference temperature monitor (traceable to National Institute of Standards and Technology (NIST) standards or an independent temperature measurement device dedicated for this purpose). During accuracy checking, the probe of the reference device shall be at the same location as that of the temperature monitor being tested.

(2) *Outlet VOC concentration.* Monitor the VOC concentrations at the outlet of the unit and record the output from the system. For sources monitoring the outlet VOC concentration established during the performance test, a data acquisition system shall record a concentration every 15 minutes and shall compute and record an average concentration each cycle (same time period or cycle as the performance test) and a 3-cycle block average concentration every third cycle. For sources monitoring the 1,000 ppmv VOC concentration for gasoline loading, a data acquisition system shall record a concentration every 15 minutes and shall compute and record an average concentration each hour and a 3-hour block average concentration every third hour. The owner or operator will install, calibrate, operate, and maintain a VOC CEMS consistent with the requirements of PS 8 to measure the VOC concentration. The daily calibration requirements are required only on days when marine tank vessel loading operations occur.

(i) *Absorber.* For sources complying with §63.563(b)(8), use of an absorber, the owner or operator shall comply with either paragraph (i)(1) or (2) of this section.

(1) *Outlet VOC concentration.* Monitor the VOC concentrations at the outlet of the absorber and record the output from the system. For sources monitoring the outlet VOC concentration established during the performance test, a data acquisition system shall record a concentration every 15 minutes and shall compute and record an average concentration each cycle (same time period or cycle as the performance test) and a 3-cycle block average concentration every third cycle. For sources monitoring the 1,000 ppmv VOC concentration for gasoline loading, a data acquisition system shall record a concentration every 15 minutes and shall compute and record an average concentration each hour and a 3-hour block average concentration every third hour. The owner or operator will install, calibrate, operate, and maintain a VOC CEMS consistent with the requirements of PS 8. The daily calibration requirements are required only on days when marine tank vessel loading operations occur.

(2) *L/V ratio.* Monitor and record the inlet liquid flowrate and the inlet gas flowrate to the absorber and record the calculated L/V ratio. The owner or operator shall install, calibrate, maintain, and operate liquid and gas flow indicators. For sources monitoring the L/V ratio established during the performance test, a data acquisition system shall record the flowrates and calculated ratio every 15 minutes and shall compute and record an average ratio each cycle (same time period or cycle as the performance test) and a 3-cycle block average ratio every third cycle. For sources monitoring the manufacturer recommended L/V ratio, a data acquisition system shall record the flowrates and calculated ratio every 15 minutes and shall compute and record an average ratio each hour and a 3-hour average ratio every third hour. The liquid and gas flow indicators shall be installed immediately upstream of the respective inlet lines to the absorber.

(j) *Alternate monitoring procedures.* Alternate procedures to those described in this section may be used upon application to, and approval by, the Administrator. The owner or operator shall comply with the procedures for use of an alternative monitoring method in §63.8(f).

§63.565 Test methods and procedures.

(a) *Performance testing.* The owner or operator of an affected source in §63.562 shall comply with the performance testing requirements in §63.7 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 the performance testing requirements in this section.

(b) *Pressure/vacuum settings of marine tank vessel's vapor collection equipment.* For the purpose of determining compliance with §63.563(a)(3), the following procedures shall be used:

(1) Calibrate and install a pressure measurement device (liquid manometer, magnehelic gauge, or equivalent instrument) capable of measuring up to the maximum relief set pressure of the pressure-vacuum vents;

(2) Connect the pressure measurement device to a pressure tap in the terminal's vapor collection system, located as close as possible to the connection with the marine tank vessel; and

(3) During the performance test required in §63.563(b)(1), record the pressure every 5 minutes while a marine tank vessel is being loaded and record the highest instantaneous pressure and vacuum that occurs during each loading cycle.

(c) *Vapor-tightness test procedures for the marine tank vessel.* When testing a vessel for vapor tightness to comply with the marine vessel vapor-tightness requirements of §63.563(a)(4)(i), the owner or operator of a source shall use the methods in either paragraph (c)(1) or (2) in this section.

(1) *Pressure test for the marine tank vessel.* (i) Each product tank shall be pressurized with dry air or inert gas to no more than the pressure of the lowest pressure relief valve setting.

(ii) Once the pressure is obtained, the dry air or inert gas source shall be shut off.

(iii) At the end of one-half hour, the pressure in the product tank and piping shall be measured. The change in pressure shall be calculated using the following formula:

$P=P_i-P_f$

Where:

P=change in pressure, inches of water.

P_i = pressure in tank when air/gas source is shut off, inches of water.

P_f = pressure in tank at the end of one-half hour after air/gas source is shut off, inches of water.

(iv) The change in pressure, P, shall be compared to the pressure drop calculated using the following formula:

$PM=0.861\ P_{ia}\ L/V$

Where:

PM=maximum allowable pressure change, inches of water.

P_{ia} = pressure in tank when air/gas source is shut off, psia.

L=maximum permitted loading rate of vessel, barrels per hour.

V=total volume of product tank, barrels.

(v) If $P \leq PM$, the vessel is vapor tight.

(vi) If $P<PM$, the vessel is not vapor tight and the source of the leak must be identified and repaired prior to retesting.

(2) *Leak test for the marine tank vessel.* Each owner or operator of a source complying with §§63.563(a)(4)(ii) or (iii) shall use Method 21 as the vapor-tightness leak test for marine tank vessels. The test shall be conducted during the final 20 percent of loading of each product tank of the marine vessel, and it shall be applied to any potential sources of vapor leaks on the vessel.

(d) *Combustion (except flare) and recovery control device performance test procedures.* (1) All testing equipment shall be prepared and installed as specified in the appropriate test methods.

(2) All testing shall be performed during the last 20 percent of loading of a tank or compartment.

(3) All emission testing intervals shall consist of each 5 minute period during the performance test. For each interval, the following shall be performed:

(i) *Readings.* The reading from each measurement instrument shall be recorded.

(ii) *Sampling Sites.* Method 1 or 1A of appendix A of part 60 of this chapter, as appropriate, shall be used for selection of sampling sites. Sampling sites shall be located at the inlet and outlet of the combustion device or recovery device except for owners or operators complying with the 1,000 ppmv VOC emissions limit for gasoline vapors under §63.563(b)(6) or (7), where the sampling site shall be located at the outlet of the recovery device.

(iii) *Volume exhausted.* The volume exhausted shall be determined using Method 2, 2A, 2C, or 2D of appendix A of part 60 of this chapter, as appropriate.

(4) *Combustion devices, except flares.* The average VOC concentration in the vent upstream and downstream of the control device shall be determined using Method 25 of appendix A of part 60 of this chapter for combustion devices, except flares. The average VOC concentration shall correspond to the volume measurement by taking into account the sampling system response time.

(5) *Recovery devices.* The average VOC concentration in the vent upstream and downstream of the control device shall be determined using Method 25A or 25B of appendix A-7 to part 60 of this chapter for recovery devices. The average VOC concentration shall correspond to the volume measurement by taking into account the sampling system response time.

(6) The VOC mass at the inlet and outlet of the combustion or recovery device during each testing interval shall be calculated as follows:

$$M_j = FKV_s\, C_{VOC}$$

Where:

M_j = mass of VOC at the inlet and outlet of the combustion or recovery device during testing interval j, kilograms (kg).

$F=10^{-6}$ = conversion factor, (cubic meters VOC/cubic meters air)(1/ppmv) (m3 VOC/m3 air)(1/ppmv).

K=density, kilograms per cubic meter (kg/m3 VOC), standard conditions, 20 °C and 760 mm Hg.

V_s = volume of air-vapor mixture at the inlet and outlet of the combustion or recovery device, cubic meters (m3) at standard conditions, 20 °C and 760 mm Hg.

C_{VOC} = VOC concentration (as measured) at the inlet and outlet of the combustion or recovery device, ppmv, dry basis.

s=standard conditions, 20 °C and 760 mm Hg.

(7) The VOC mass emission rates at the inlet and outlet of the recovery or combustion device shall be calculated as follows:

$$E_i = \frac{\sum_{j=1}^{n} M_{ij}}{T}$$

$$E_o = \frac{\sum_{j=1}^{n} M_{oj}}{T}$$

Where:

E_i, E_o = mass flow rate of VOC at the inlet (i) and outlet (o) of the recovery or combustion device, kilogram per hour (kg/hr).

M_{ij}, M_{oj} = mass of VOC at the inlet (i) or outlet (o) during testing interval j, kg.

T=Total time of all testing intervals, hour.

n=number of testing intervals.

(8) Where Method 25, 25A, or 25B is used to measure the percent reduction in VOC, the percent reduction across the combustion or recovery device shall be calculated as follows:

$$R = \frac{E_i - E_o}{E_i} (100\%)$$

Where:

R = control efficiency of control device, percent.

E_i = mass flow rate of VOC at the inlet to the combustion or recovery device as calculated under paragraph (c)(7) of this section, kg/hr.

E_o = mass flow rate of VOC at the outlet of the combustion or recovery device, as calculated under paragraph (c)(7) of this section, kg/hr.

(9) Repeat the procedures in paragraph (d)(1) through (d)(8) of this section 3 times. The arithmetic average percent efficiency of the three runs shall determine the overall efficiency of the control device.

(10) Use of methods other than Method 25, 25A, or 25B shall be validated pursuant to Method 301 of appendix A to part 63 of this chapter.

(e) *Performance test for flares.* When a flare is used to comply with §63.562(b)(2), (3), and (4), (c)(3) and (4), and (d)(2), the source must demonstrate that the flare meets the requirements of §63.11 of subpart A of this part. In addition, a performance test according to Method 22 of appendix A of part 63 shall be performed to determine visible emissions. The observation period shall be at least 2 hours and shall be conducted according to Method 22. Performance testing shall be conducted during three complete loading cycles with a separate test run for each loading cycle. The observation period for detecting visible emissions shall encompass each loading cycle. Integrated sampling to measure process vent stream flow rate shall be performed continuously during each loading cycle. The owner or operator shall record all visible emission readings, heat content determinations, flow rate measurements, maximum permitted velocity calculations, and exit velocity determinations made during the performance test.

(f) *Baseline temperature.* The procedures in this paragraph shall be used to determine the baseline temperature required in §63.563(b)(4), (6), and (7) for combustion devices, carbon adsorber beds, and condenser/refrigeration units, respectively, and to monitor the temperature as required in §63.564(e), (g), and (h). The owner or operator shall comply with either paragraph (f)(1) or (2) of this section.

(1) *Baseline temperature from performance testing.* The owner or operator shall establish the baseline temperature as the temperature at the outlet point of the unit averaged over three test runs from paragraph (d) of this section. Temperature shall be measured every 15 minutes.

(2) *Baseline temperature from manufacturer.* The owner or operator shall establish the baseline temperature as the manufacturer recommended minimum operating temperature for combustion devices, maximum operating temperature for condenser units, and maximum operating temperature for carbon beds of carbon adsorbers.

(g) *Baseline outlet VOC concentration.* The procedures in this paragraph shall be used to determine the outlet VOC concentration required in §63.563(b)(4), (6), (7), and (8) for combustion devices except flare, carbon adsorbers, condenser/refrigeration units, and absorbers, respectively, and to monitor the VOC concentration as required in §63.564(e), (g), (h), and (i). The owner or operator shall use the procedures outlined in Method 25A or 25B. For the baseline VOC concentration, the arithmetic average of the outlet VOC concentration from three test runs from paragraph (d) of this section shall be calculated for the control device. The VOC concentration shall be measured at least every 15 minutes. Compliance testing of VOC CEMS shall be performed using PS 8.

(h) *Baseline regeneration time for carbon bed regeneration.* The procedures in this paragraph shall be used to demonstrate the baseline regeneration time for the vacuum stage of carbon bed regeneration required in §63.563(b)(6) for a carbon adsorber and to monitor the regeneration time for the vacuum regeneration as required in §63.564(g). The owner or operator shall comply with paragraph (h)(1) or (2).

(1) *Baseline regeneration time from performance testing.* The owner or operator shall establish the baseline regeneration time as the length of time for the vacuum stage of carbon bed regeneration averaged over three test runs from paragraph (d) of this section.

(2) *Baseline regeneration time from manufacturer recommendation.* The owner or operator shall establish the baseline regeneration time as the manufacturer recommended minimum regeneration time for the vacuum stage of carbon bed regeneration.

(i) *Baseline vacuum pressure for carbon bed regeneration.* The procedures in this paragraph shall be used to demonstrate the baseline vacuum pressure for the vacuum stage of carbon bed regeneration required in §63.563(b)(6) for a carbon adsorber and to monitor the vacuum pressure as required in §63.564(g). The owner or operator shall establish the baseline vacuum pressure as the manufacturer recommended minimum vacuum for carbon bed regeneration.

(j) *Baseline total stream flow.* The procedures in this paragraph shall be used to demonstrate the baseline total stream flow for steam regeneration required in §63.563(b)(6) for a carbon adsorber and to monitor the total stream flow as required in §63.564(g). The owner or operator shall establish the baseline stream flow as the manufacturer recommended minimum total stream flow for carbon bed regeneration.

(k) *Baseline L/V ratio.* The procedures in this paragraph shall be used to determine the baseline L/V ratio required in §63.563(b)(8) for an absorber and to monitor the L/V ratio as required in §63.564(i). The owner or operator shall comply with either paragraph (k)(1) or (2) of this section.

(1) *Baseline L/V ratio from performance test.* The owner or operator shall establish the baseline L/V ratio as the calculated value of the inlet liquid flow divided by the inlet gas flow to the absorber averaged over three test runs using the procedures in paragraph (d) of this section.

(2) *Baseline L/V ratio from manufacturer.* The owner or operator shall establish the baseline L/V ratio as the manufacturer recommended minimum L/V ratio for absorber operation.

(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.

(m) *Alternate test procedures.* (1) Alternate test procedures to those described in this section may be used upon application to, and approval by, the Administrator.

(2) If the owner or operator intends to demonstrate compliance by using an alternative to any test method specified, the owner or operator shall refrain from conducting the performance test until the Administrator approves the use of the alternative method when the Administrator approves the site-specific test plan (if review of the site-specific test plan is requested) or until after the alternative method is approved (see §63.7(f) of subpart A of this part). If the Administrator does not approve the site-specific test plan (if review is requested) or the use of the alternative method within 30 days before the test is scheduled to begin, the performance test dates specified in §63.563(b)(1) shall be extended such that the owner or operator shall conduct the performance test within 60 calendar days after the Administrator approves the site-specific test plan or after use of the alternative method is approved. Notwithstanding the requirements in the preceding two sentences, the owner or operator may proceed to conduct the performance test as required in this section (without the Administrator's prior approval of the site-specific test plan) if he/she subsequently chooses to use the specified testing and monitoring methods instead of an alternative.

[60 FR 48399, Sept. 19, 1995, as amended at 79 FR 11283, Feb. 27, 2014]

§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.

(a) The owner or operator of an affected source shall fulfill all reporting and recordkeeping requirements in §§63.9 and 63.10 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 fulfill all reporting and recordkeeping requirements in this section. These reports will be made to the Administrator at the appropriate address identified in §63.13 of subpart A of this part.

(1) Reports required by subpart A and this section may be sent by U.S. mail, facsimile (fax), or by another courier.

(i) Submittals sent by U.S. mail shall be postmarked on or before the specified date.

(ii) Submittals sent by other methods shall be received by the Administrator on or before the specified date.

(2) If acceptable to both the Administrator and the owner or operator of a source, reports may be submitted on electronic media.

(b) *Notification requirements.* The owner or operator of an affected source shall fulfill all notification requirements in §63.9 of subpart A of this part in accordance with the provisions for applicability of that section to this subpart in Table 1 of §63.560 and the notification requirements in this paragraph.

(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.

(2) *Initial notification for sources with startup before the effective date.* The owner or operator of a source with initial startup before the effective date shall notify the Administrator in writing that the source is subject to the relevant standard. The notification shall be submitted not later than 365 days after the effective date of the emissions standards and shall provide the following information:

(i) The name and address of the owner or operator;

(ii) The address (i.e., physical location) of the source;

(iii) An identification of this emissions standard that is the basis of the notification and the source's compliance date;

(iv) A brief description of the nature, size, design, and method of operation of the source;

(v) A statement that the source is a major source.

(3) *Initial notification for sources with startup after the effective date.* The owner or operator of a new or reconstructed source or a source that has been reconstructed such that it is subject to the emissions standards that has an initial startup after the effective date but before the compliance date, and for which an application for approval of construction or reconstruction is not required under §63.5(d) of subpart A of this part and §63.566 of this subpart, shall notify the Administrator in writing that the source is subject to the standard no later than 365 days or 120 days after initial startup, whichever occurs before notification of the initial performance test in §63.9(e) of subpart A of this part. The notification shall provide all the information required in paragraph (b)(2) of this section, delivered or postmarked with the notification required in paragraph (b)(4) of this section.

(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.

(5) *Additional initial notification requirements.* (i) The owner or operator of sources subject to §63.562(b)(2), (3), and (4), MACT standards, shall also include in the initial notification report required by paragraph (b)(2) and (3) the 24-month annual average or the annual actual HAP emissions from marine tank vessel loading operations, as appropriate, at all loading berths, as calculated according to the procedures in §63.565(l). Emissions will be reported by commodity and type of marine tank vessel (barge or tanker) loaded.

(ii) As an alternative to reporting the information in paragraph (b)(5)(i) of this section, the source may submit documentation showing that all HAP-containing marine tank vessel loading operations, not exempt by §63.560(d), occurred using vapor tight vessels that comply with the procedures of §63.563(a) and that the emissions were routed to control devices meeting the requirements specified in §63.563(b).

(c) *Request for extension of compliance.* If the owner or operator has installed BACT or technology to meet LAER consistent with §63.6(i)(5) of subpart A of this part, he/she may submit to the Administrator (or State with an approved permit program) a request for an extension of compliance as specified in §63.6(i)(4)(i)(B), (i)(5), and (i)(6) of subpart A of this part.

(d) *Reporting for performance testing of flares.* The owner or operator of a source required to conduct an opacity performance test shall report the opacity results and other information required by §63.565(e) and §63.11 of subpart A of this part with the notification of compliance status.

(e) *Summary reports and excess emissions and monitoring system performance reports*—(1) *Schedule for summary report and excess emissions and monitoring system performance reports.* Excess emissions and parameter monitoring exceedances are defined in §63.563(b). The owner or operator of a source subject to these emissions standards that is required to install a CMS shall submit an excess emissions and continuous monitoring system performance report and/or a summary report to the Administrator once each year, except, when the source experiences excess emissions, the source shall comply with a semi-annual reporting format until a request to reduce reporting frequency under paragraph (e)(2) of this section is approved.

(2) *Request to reduce frequency of excess emissions and continuous monitoring system performance reports.* An owner or operator who is required to submit excess emissions and continuous monitoring system performance and summary reports on a semi-annual basis may reduce the frequency of reporting to annual if the following conditions are met:

(i) For 1 full year the sources's excess emissions and continuous monitoring system performance reports continually demonstrate that the source is in compliance; and

(ii) The owner or operator continues to comply with all recordkeeping and monitoring requirements specified in this subpart and subpart A of this part.

(3) The frequency of reporting of excess emissions and continuous monitoring system performance and summary reports required may be reduced only after the owner or operator notifies the Administrator in writing of his or her intention to make such a change and the Administrator does not object to the intended change. In deciding whether to approve a reduced frequency of reporting, the Administrator may review information concerning the source's entire previous performance history during the 5-year recordkeeping prior to the intended change, including performance test results, monitoring data, and evaluations of an owner or operator's conformance with operation maintenance requirements. Such information may be used by the Administrator to make a judgement about the source's potential for noncompliance in the future. If the Administrator will notify the owner or operator in writing within 45 days after receiving notice of the owner or operator's intention. The notification from the Administrator to the owner or operator will specify the grounds on which the disapproval is based. In the absence of a notice of disapproval within 45 days, approval is automatically granted.

(4) *Content and submittal dates for excess emissions and monitoring system performance reports.* All excess emissions and monitoring system performance reports and all summary reports, if required per paragraph (e)(5) and (6) of this section, shall be delivered or postmarked within 30 days following the end of each calendar year, or within 30 days following the end of each six month period, if appropriate. Written reports of excess emissions or exceedances of process or control system parameters shall include all information required in §63.10(c)(5) through (13) of subpart A of this part as applicable in Table 1 of §63.560 and information from any calibration tests in which the monitoring equipment is not in compliance with PS 8 or other methods used for accuracy testing of temperature, pressure, or flow monitoring devices. The written report shall also include the name, title, and signature of the responsible official who is certifying the accuracy of the report. When no excess emissions or exceedances have occurred or monitoring equipment has not been inoperative, repaired, or adjusted, such information shall be stated in the report. This information will be kept for a minimum of 5 years and made readily available to the Administrator or delegated State authority upon request.

(5) If the total duration of excess emissions or control system parameter exceedances for the reporting period is less than 5 percent of the total operating time for the reporting period, and CMS downtime for the reporting period is less than 10 percent of the total operating time for the reporting period, only the summary report of §63.10(e)(3)(vi) of subpart A of this part shall be submitted, and the full excess emissions and continuous monitoring system performance report of paragraph (e)(4) of this section need not be submitted unless required by the Administrator.

(6) If the total duration of excess emissions or process or control system parameter exceedances for the reporting period is 5 percent or greater of the total operating time for the reporting period, or the total CMS downtime for the reporting period is 10 percent or greater of the total operating time for the reporting period, both the summary report of §63.10(e)(3)(vi) of subpart A of this part and the excess emissions and continuous monitoring system performance report of paragraph (e)(4) of this section shall be submitted.

(f) *Vapor collection system of the terminal.* Each owner or operator of an affected source shall submit with the initial performance test and maintain in an accessible location on site an engineering report describing in detail the vent system, or vapor collection system, used to vent each vent stream to a control device. This report shall include all valves and vent pipes that could vent the stream to the atmosphere, thereby bypassing the control device, and identify which valves are car-sealed opened and which valves are car-sealed closed.

(g) If a vent system, or vapor collection system, containing valves that could divert the emission stream away from the control device is used, each owner or operator of an affected source shall keep for at least 5 years up-to-date, readily accessible continuous records of:

(1) All periods when flow bypassing the control device is indicated if flow indicators are installed under §63.563(a)(1) and §63.564(b), and

(2) All times when maintenance is performed on car-sealed valves, when the car-seal is broken, and when the valve position is changed (i.e., from open to closed for valves in the vent piping to the control device and from closed to open for valves that vent the stream directly or indirectly to the atmosphere bypassing the control device) if valves are monitored under §63.564(b).

(h) The owner or operator of an affected source shall keep the vapor-tightness documentation required under §63.563(a)(4) on file at the source in a permanent form available for inspection.

(i) *Vapor tightness test documentation for marine tank vessels.* The owner or operator of an affected source shall maintain a documentation file for each marine tank vessel loaded at that source to reflect current test results as determined by the appropriate method in §63.565(c)(1) and (2). Updates to this documentation file shall be made at least once per year. The owner or operator shall include, as a minimum, the following information in this documentation:

(1) Test title;

(2) Marine vessel owner and address;

(3) Marine vessel identification number;

(4) Loading time, according to §63.563(a)(4)(ii) or (iii), if appropriate;

(5) Testing location;

(6) Date of test;

(7) Tester name and signature;

(8) Test results from §63.565(c)(1) or (2), as appropriate;

(9) Documentation provided under §63.563(a)(4)(ii) and (iii)(B) showing that the repair of leaking components attributed to a failure of a vapor-tightness test is technically infeasible without dry-docking the vessel; and

(10) Documentation that a marine tank vessel failing a pressure test or leak test has been repaired.

(j) *Emission estimation reporting and recordkeeping procedures.* The owner or operator of each source complying with the emission limits specified in §63.562(b)(2), (3), and (4) shall comply with the following provisions:

(1) Maintain records of all measurements, calculations, and other documentation used to identify commodities exempted under §63.560(d);

(2) Keep readily accessible records of the emission estimation calculations performed in §63.565(l) for 5 years; and

(3) Submit an annual report of the source's HAP control efficiency calculated using the procedures specified in §63.565(l), based on the source's actual throughput.

(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.

(k) *Leak detection and repair of vapor collection systems and control devices.* When each leak of the vapor collection system, or vapor collection system, and control device is detected and repaired as specified in §63.563(c) the following information required shall be maintained for 5 years:

(1) Date of inspection;

(2) Findings (location, nature, and severity of each leak);

(3) Leak determination method;

(4) Corrective action (date each leak repaired, reasons for repair interval); and

(5) Inspector name and signature.

(l) The owner or operator of the VMT source required by §63.562(d)(2)(iv) to develop a program, shall submit annual reports on or before January 31 of each year to the Administrator certifying the annual average daily loading rate for the previous calendar year. Beginning on January 31, 1996, for the reported year 1995, the annual report shall specify the annual average daily loading rate over all loading berths. Beginning on January 31, 1999, for the reported year 1998, the annual report shall specify the annual average daily loading rate over all loading berths, over each loading berth equipped with a vapor collection system and control device, and over each loading berth not equipped with a vapor collection system and control device. The annual average daily loading rate under this section is calculated as the total amount of crude oil loaded during the calendar year divided by 365 days or 366 days, as appropriate.

(m) The number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded shall be stated in a semiannual report. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §63.562(e), including actions taken to correct a malfunction. The report, to be certified by the owner or operator or other responsible official, shall be submitted semiannually and delivered or postmarked by the 30th day following the end of each calendar half.

(n)(1) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in §63.2, and as required in this subpart, you must submit performance test data, except opacity data, electronically to EPA's Central Data Exchange by using the ERT (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(2) All reports required by this subpart not subject to the requirements in paragraph (n)(1) of this section must be sent to the Administrator at the appropriate address listed in §63.13. If acceptable to both the Administrator and the owner or operator of a source, these reports may be submitted on electronic media. The Administrator retains the right to require submittal of reports subject to paragraph (n)(1) of this section in paper format.

[60 FR 48399, Sept. 19, 1995, as amended at 68 FR 37350, June 23, 2003; 76 FR 22597, Apr. 21, 2011]

§63.568 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 §§63.560 and 63.562(a) through (d).

(2) Approval of major alternatives to test methods for 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.

[68 FR 37350, June 23, 2003]

Attachment E.iii

Part 70 Operating Permit No: T089-30396-00453

Electronic Code of Federal Regulations

Title 40: Protection of Environment

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

Subpart CC—National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries

Source: 60 FR 43260, Aug. 18, 1995, unless otherwise noted.

§63.640 Applicability and designation of affected source.

(a) This subpart applies to petroleum refining process units and to related emissions points that are specified in paragraphs (c)(1) through (8) of this section that are located at a plant site and that meet the criteria in paragraphs (a)(1) and (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.

(b)(1) If the predominant use of the flexible operation unit, as described in paragraphs (b)(1)(i) and (ii) of this section, is as a petroleum refining process unit, as defined in §63.641, then the flexible operation unit shall be subject to the provisions of this subpart.

(i) Except as provided in paragraph (b)(1)(ii) of this section, the predominant use of the flexible operation unit shall be the use representing the greatest annual operating time.

(ii) If the flexible operation unit is used as a petroleum refining process unit and for another purpose equally based on operating time, then the predominant use of the flexible operation unit shall be the use that produces the greatest annual production on a mass basis.

(2) The determination of applicability of this subpart to petroleum refining process units that are designed and operated as flexible operation units shall be reported as specified in §63.655(h)(6)(i).

(c) For the purposes of this subpart, the affected source shall comprise all emissions points, in combination, listed in paragraphs (c)(1) through (c)(8) 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;

(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; and

(8) All heat exchange systems, as defined in this subpart.

(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 of a storage vessel constructed on or before August 18, 1994, 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. The owner or operator of a storage vessel constructed after August 18, 1994, shall follow the procedures specified in paragraphs (e)(1), (e)(2)(i), and (e)(2)(ii) 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 August 18, 1995. This determination shall be reported as specified in §63.655(h)(6)(ii).

(f) The owner or operator of a distillation unit constructed on or before August 18, 1994, shall follow the procedures specified in paragraphs (f)(1) through (f)(4) of this section to determine whether a miscellaneous process vent from a distillation unit is part of a source to which this subpart applies. The owner or operator of a distillation unit constructed after August 18, 1994, 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 August 18, 1995. This determination shall be reported as specified in §63.655(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)(6) of this section.

(1) Except as provided in paragraphs (h)(1)(i) and (ii) of this section, new sources that commence construction or reconstruction after July 14, 1994, shall be in compliance with this subpart upon initial startup or August 18, 1995, whichever is later.

(i) At new sources that commence construction or reconstruction after July 14, 1994, but on or before September 4, 2007, heat exchange systems shall be in compliance with the existing source requirements for heat exchange systems specified in §63.654 no later than October 29, 2012.

(ii) At new sources that commence construction or reconstruction after September 4, 2007, heat exchange systems shall be in compliance with the new source requirements in §63.654 upon initial startup or October 28, 2009, whichever is later.

(2) Except as provided in paragraphs (h)(3) through (h)(6) 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)(5) 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 of this subpart at the first degassing and cleaning activity after August 18, 1998, or August 18, 2005, 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.

(6) Heat exchange systems at an existing source shall be in compliance with the existing source standards in §63.654 no later than October 29, 2012.

(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 August 18, 1995, 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 November 16, 1995);

(ii) The Notification of Compliance Status report as required by §63.655(f) for a new source, addition, or change;

(iii) Periodic Reports and other reports as required by §63.655(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), (h)(1) through (h)(3), and (k) 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, marine tank vessel loading operation, or heat exchange system that meets the criteria in paragraphs (c)(1) through (8) of this section is added to an existing petroleum refinery or if another deliberate operational process change creating an additional Group 1 emissions 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 (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 §63.655(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 August 18, 1998, 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 August 18, 1998, 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, marine tank vessel loading operation, or heat exchange system meeting the criteria in paragraphs (c)(1) through (8) 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 (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 §63.655(f) for the emission points that were added or changed;

(ii) Periodic Reports and other reports as required by §63.655(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), (h)(1) through (h)(3), and (k) 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. 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.

(2) After the compliance dates specified in paragraph (h) of this section a Group 1 or Group 2 wastewater stream that is conveyed, stored, or treated in a wastewater stream management unit that also receives streams subject to the provisions of §§63.133 through 63.147 of subpart G wastewater provisions of this part shall comply as specified in paragraph (o)(2)(i) or (o)(2)(ii) of this section. Compliance with the provisions of paragraph (o)(2) of this section shall constitute compliance with the requirements of this subpart for that wastewater stream.

(i) Comply with paragraphs (o)(2)(i)(A) through (o)(2)(i)(C) of this section.

(A) The provisions in §§63.133 through 63.140 of subpart G for all equipment used in the storage and conveyance of the Group 1 or Group 2 wastewater stream.

(B) The provisions in both 40 CFR part 61, subpart FF and in §§63.138 and 63.139 of subpart G for the treatment and control of the Group 1 or Group 2 wastewater stream.

(C) The provisions in §§63.143 through 63.148 of subpart G for monitoring and inspections of equipment and for recordkeeping and reporting requirements. The owner or operator is not required to comply with the monitoring, recordkeeping, and reporting requirements associated with the treatment and control requirements in 40 CFR part 61, subpart FF, §§61.355 through 61.357.

(ii) Comply with paragraphs (o)(2)(ii)(A) and (o)(2)(ii)(B) of this section.

(A) Comply with the provisions of §§63.133 through 63.148 and §§63.151 and 63.152 of subpart G.

(B) For any Group 2 wastewater stream or organic stream whose benzene emissions are subject to control through the use of one or more treatment processes or waste management units under the provisions of 40 CFR part 61, subpart FF on or after December 31, 1992, comply with the requirements of §63.133 through §63.147 of subpart G for Group 1 wastewater streams.

(p) Overlap of subpart CC with other regulations for equipment leaks.

(1) 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 standards promulgated before September 4, 2007, are required to comply only with the provisions specified in this subpart.

(2) Equipment leaks that are also subject to the provisions of 40 CFR part 60, subpart GGGa, are required to comply only with the provisions specified in 40 CFR part 60, subpart GGGa.

(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.

[60 FR 43260, Aug. 18, 1995; 61 FR 7051, Feb. 23, 1996, as amended at 61 FR 29878, June 12, 1996; 63 FR 44140, Aug. 18, 1998; 66 FR 28841, May 25, 2001; 74 FR 55683, Oct. 28, 2009; 78 FR 37145, June 20, 2013]

§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 §63.655(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.

Cooling tower means a heat removal device used to remove the heat absorbed in circulating cooling water systems by transferring the heat to the atmosphere using natural or mechanical draft.

Cooling tower return line means the main water trunk lines at the inlet to the cooling tower before exposure to the atmosphere.

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.

Heat exchange system means a device or collection of devices used to transfer heat from process fluids to water without intentional direct contact of the process fluid with the water (*i.e.,* non-contact heat exchanger) and to transport and/or cool the water in a closed-loop recirculation system (cooling tower system) or a once-through system (e.g., river or pond water). For closed-loop recirculation systems, the *heat exchange system* consists of a cooling tower, all petroleum refinery process unit heat exchangers that are in organic HAP service, as defined in this subpart, serviced by that cooling tower, and all water lines to and from these petroleum refinery process unit heat exchangers. For once-through systems, the *heat exchange system* consists of all heat exchangers that are in organic HAP service, as defined in this subpart, servicing an individual petroleum refinery process unit and all water lines to and from these heat exchangers. Sample coolers or pump seal coolers are not considered heat exchangers for the purpose of this definition and are not part of the *heat exchange system.* Intentional direct contact with process fluids results in the formation of a wastewater.

Heat exchanger exit line means the cooling water line from the exit of one or more heat exchangers (where cooling water leaves the heat exchangers) to either the entrance of the cooling tower return line or prior to exposure to the atmosphere, in, as an example, a once-through cooling system, whichever occurs first.

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 or *in organic HAP 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 as determined according to the provisions of §63.180(d) of this part and table 1 of this subpart. The provisions of §63.180(d) 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.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29879, June 12, 1996; 62 FR 7938, Feb. 21, 1997; 63 FR 31361, June 9, 1998; 63 FR 44141, Aug. 18, 1998; 74 FR 55685, Oct. 28, 2008; 78 FR 37146, June 20, 2013]

§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.

(b) [Reserved]

(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.

(h) The owner or operator of a new source subject to the requirements of this subpart shall control emissions of organic HAP's to the level represented by the equation in paragraph (g) of this section.

(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.

(j) The owner or operator of a new source shall demonstrate compliance with the emission standard in paragraph (h) of this section only by following the procedures in paragraph (k) of this section. The owner or operator of a new source may not use the emissions averaging compliance approach.

(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 §63.655 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.

(l) The owner or operator of an existing source may elect to control some of the emission points within the source to different levels than specified under §§63.643 through 63.647, §§63.650 and 63.651 by using an emissions averaging compliance approach as long as the overall emissions for the source do not exceed the emission level specified in paragraph (g) of this section. The owner or operator using emissions averaging shall meet the requirements in paragraphs (l)(1) and (l)(2) of this section.

(1) Calculate emission debits and credits for those emission points involved in the emissions average according to the procedures specified in §63.652; and

(2) Comply with the requirements of §§63.652, 63.653, and 63.655, as applicable.

(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.

[60 FR 43260, Aug. 18, 1995; 61 FR 7051, Feb. 23, 1996, as amended at 61 FR 29879, June 12, 1996; 74 FR 55685, Oct. 28, 2009]

§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.

(2) Reduce emissions of organic HAP's, using a control device, by 98 weight-percent or to a concentration of 20 parts per million by volume, on a dry basis, corrected to 3 percent oxygen, whichever is less stringent. Compliance can be determined by measuring either organic HAP's or TOC's using the procedures in §63.645.

(b) If a boiler or process heater is used to comply with the percentage of reduction requirement or concentration limit specified in paragraph (a)(2) of this section, then the vent stream shall be introduced into the flame zone of such a device, or in a location such that the required percent reduction or concentration is achieved. Testing and monitoring is required only as specified in §§63.644(a) and 63.645 of this subpart.

§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.

(1) Where an incinerator is used, a temperature monitoring device equipped with a continuous recorder is required.

(i) Where an incinerator other than a catalytic incinerator is used, a temperature monitoring device shall be installed in the firebox or in the ductwork immediately downstream of the firebox in a position before any substantial heat exchange occurs.

(ii) Where a catalytic incinerator is used, temperature monitoring devices shall be installed in the gas stream immediately before and after the catalyst bed.

(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.

(3) Any boiler or process heater with a design heat input capacity greater than or equal to 44 megawatt or any boiler or process heater in which all vent streams are introduced into the flame zone is exempt from monitoring.

(4) Any boiler or process heater less than 44 megawatts design heat capacity where the vent stream is not introduced into the flame zone is required to use a temperature monitoring device in the firebox equipped with a continuous recorder.

(b) An owner or operator of a Group 1 miscellaneous process vent may request approval to monitor parameters other than those listed in paragraph (a) of this section. The request shall be submitted according to the procedures specified in §63.655(h). Approval shall be requested if the owner or operator:

(1) Uses a control device other than an incinerator, boiler, process heater, or flare; or

(2) Uses one of the control devices listed in paragraph (a) of this section, but seeks to monitor a parameter other than those specified in paragraph (a) of this section.

(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 §63.655(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 §63.655(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 §63.655(g)(6), or failure to perform procedures required by this section shall constitute a violation of the applicable emission standard of this subpart.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 63 FR 44141, Aug. 18, 1998; 74 FR 55685, Oct. 28, 2009]

§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 §63.655(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.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 63 FR 44141, Aug. 18, 1998; 74 FR 55685, Oct. 28, 2009]

§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) mean the Notification of Compliance Status required by §63.655(f).

(k) References to the Periodic Reports in §63.152(c) mean the Periodic Report required by §63.655(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.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 62 FR 7939, Feb. 21, 1997; 74 FR 55685, Oct. 28, 2009; 75 FR 37731, June 30, 2010]

§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.

(2) Calculation of percentage leaking equipment components for subpart VV of 40 CFR part 60 may be done on a process unit basis or a sourcewide basis. Once the owner or operator has decided, all subsequent calculations shall be on the same basis unless a permit change is made.

(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.

(c) In lieu of complying with the existing source provisions of paragraph (a) in this section, an owner or operator may elect to comply with the requirements of §§63.161 through 63.169, 63.171, 63.172, 63.175, 63.176, 63.177, 63.179, and 63.180 of subpart H of this part except as provided in paragraphs (c)(1) through (c)(10) and (e) through (i) of this section.

(1) The instrument readings that define a leak for light liquid pumps subject to §63.163 of subpart H of this part and gas/vapor and light liquid valves subject to §63.168 of subpart H of this part are specified in table 2 of this subpart.

(2) In phase III of the valve standard, the owner or operator may monitor valves for leaks as specified in paragraphs (c)(2)(i) or (c)(2)(ii) of this section.

(i) If the owner or operator does not elect to monitor connectors, then the owner or operator shall monitor valves according to the frequency specified in table 8 of this subpart.

(ii) If an owner or operator elects to monitor connectors according to the provisions of §63.649, paragraphs (b), (c), or (d), then the owner or operator shall monitor valves at the frequencies specified in table 9 of this subpart.

(3) The owner or operator shall decide no later than the first required monitoring period after the phase I compliance date specified in §63.640(h) whether to calculate the percentage leaking valves on a process unit basis or on a sourcewide basis. Once the owner or operator has decided, all subsequent calculations shall be on the same basis unless a permit change is made.

(4) The owner or operator shall decide no later than the first monitoring period after the phase III compliance date specified in §63.640(h) whether to monitor connectors according to the provisions in §63.649, paragraphs (b), (c), or (d).

(5) Connectors in gas/vapor service or light liquid service are subject to the requirements for connectors in heavy liquid service in §63.169 of subpart H of this part (except for the agitator provisions). The leak definition for valves, connectors, and instrumentation systems subject to §63.169 is 1,000 parts per million.

(6) In phase III of the pump standard, except as provided in paragraph (c)(7) of this section, owners or operators that achieve less than 10 percent of light liquid pumps leaking or three light liquid pumps leaking, whichever is greater, shall monitor light liquid pumps monthly.

(7) Owners or operators that achieve less than 3 percent of light liquid pumps leaking or one light liquid pump leaking, whichever is greater, shall monitor light liquid pumps quarterly.

(8) An owner or operator may make the election described in paragraphs (c)(3) and (c)(4) of this section at any time except that any election to change after the initial election shall be treated as a permit modification according to the terms of part 70 of this chapter.

(9) When complying with the requirements of §63.168(e)(3)(i), non-repairable valves shall be included in the calculation of percent leaking valves the first time the valve is identified as leaking and non-repairable. Otherwise, a number of non-repairable valves up to a maximum of 1 percent per year of the total number of valves in organic HAP service up to a maximum of 3 percent may be excluded from calculation of percent leaking valves for subsequent monitoring periods. When the number of non-repairable valves exceeds 3 percent of the total number of valves in organic HAP service, the number of non-repairable valves exceeding 3 percent of the total number shall be included in the calculation of percent leaking valves.

(10) If in phase III of the valve standard any valve is designated as being leakless, the owner or operator has the option of following the provisions of 40 CFR 60.482-7(f). If an owner or operator chooses to comply with the provisions of 40 CFR 60.482-7(f), the valve is exempt from the valve monitoring provisions of §63.168 of subpart H of this part.

(d) Upon startup of new sources, the owner or operator shall comply with §63.163(a)(1)(ii) of subpart H of this part for light liquid pumps and §63.168(a)(1)(ii) of subpart H of this part for gas/vapor and light liquid valves.

(e) For reciprocating pumps in heavy liquid service and agitators in heavy liquid service, owners and operators are not required to comply with the requirements in §63.169 of subpart H of this part.

(f) Reciprocating pumps in light liquid service are exempt from §§63.163 and 60.482 if recasting the distance piece or reciprocating pump replacement is required.

(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.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 63 FR 44141, Aug. 18, 1998]

§63.649 Alternative means of emission limitation: Connectors in gas/vapor service and light liquid service.

(a) If an owner or operator elects to monitor valves according to the provisions of §63.648(c)(2)(ii), the owner or operator shall implement one of the connector monitoring programs specified in paragraphs (b), (c), or (d) of this section.

(b) *Random 200 connector alternative.* The owner or operator shall implement a random sampling program for accessible connectors of 2.0 inches nominal diameter or greater. The program does not apply to inaccessible or unsafe-to-monitor connectors, as defined in §63.174 of subpart H. The sampling program shall be implemented source-wide.

(1) Within the first 12 months after the phase III compliance date specified in §63.640(h), a sample of 200 connectors shall be randomly selected and monitored using Method 21 of 40 CFR part 60, appendix A.

(2) The instrument reading that defines a leak is 1,000 parts per million.

(3) 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 paragraph (e) of this section. A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(4) If a leak is detected, the connector shall be monitored for leaks within the first 3 months after its repair.

(5) After conducting the initial survey required in paragraph (b)(1) of this section, the owner or operator shall conduct subsequent monitoring of connectors at the frequencies specified in paragraphs (b)(5)(i) through (b)(5)(iv) of this section.

(i) If the percentage leaking connectors is 2.0 percent or greater, the owner or operator shall survey a random sample of 200 connectors once every 6 months.

(ii) If the percentage leaking connectors is 1.0 percent or greater but less than 2.0 percent, the owner or operator shall survey a random sample of 200 connectors once per year.

(iii) If the percentage leaking connectors is 0.5 percent or greater but less than 1.0 percent, the owner or operator shall survey a random sample of 200 connectors once every 2 years.

(iv) If the percentage leaking connectors is less than 0.5 percent, the owner or operator shall survey a random sample of 200 connectors once every 4 years.

(6) Physical tagging of the connectors to indicate that they are subject to the monitoring provisions is not required. Connectors may be identified by the area or length of pipe and need not be individually identified.

(c) *Connector inspection alternative.* The owner or operator shall implement a program to monitor all accessible connectors in gas/vapor service that are 2.0 inches (nominal diameter) or greater and inspect all accessible connectors in light liquid service that are 2 inches (nominal diameter) or greater as described in paragraphs (c)(1) through (c)(7) of this section. The program does not apply to inaccessible or unsafe-to-monitor connectors.

(1) Within 12 months after the phase III compliance date specified in §63.640(h), all connectors in gas/vapor service shall be monitored using Method 21 of 40 CFR part 60 appendix A. The instrument reading that defines a leak is 1,000 parts per million.

(2) All connectors in light liquid service shall be inspected for leaks. A leak is detected if liquids are observed to be dripping at a rate greater than three drops per minute.

(3) 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 paragraph (e) of this section. A first attempt at repair shall be made no later than 5 calendar days after the leak is detected.

(4) If a leak is detected, connectors in gas/vapor service shall be monitored for leaks within the first 3 months after repair. Connectors in light liquid service shall be inspected for indications of leaks within the first 3 months after repair. A leak is detected if liquids are observed to be dripping at a rate greater than three drops per minute.

(5) After conducting the initial survey required in paragraphs (c)(1) and (c)(2) of this section, the owner or operator shall conduct subsequent monitoring at the frequencies specified in paragraphs (c)(5)(i) through (c)(5)(iii) of this section.

(i) If the percentage leaking connectors is 2.0 percent or greater, the owner or operator shall monitor or inspect, as applicable, the connectors once per year.

(ii) If the percentage leaking connectors is 1.0 percent or greater but less than 2.0 percent, the owner or operator shall monitor or inspect, as applicable, the connectors once every 2 years.

(iii) If the percentage leaking connectors is less than 1.0 percent, the owner or operator shall monitor or inspect, as applicable, the connectors once every 4 years.

(6) The percentage leaking connectors shall be calculated for connectors in gas/vapor service and for connectors in light liquid service. The data for the two groups of connectors shall not be pooled for the purpose of determining the percentage leaking connectors.

(i) The percentage leaking connectors shall be calculated as follows:

$\% C_L = [(C_L - C_{AN})/C_t + C_c)] \times 100$

where:

$\% C_L$ = Percentage leaking connectors.

C_L = Number of connectors including nonrepairables, measured at 1,000 parts per million or greater, by Method 21 of 40 CFR part 60, appendix A.

C_{AN} = Number of allowable nonrepairable connectors, as determined by monitoring, not to exceed 3 percent of the total connector population, C_t.

C_t = Total number of monitored connectors, including nonrepairables, in the process unit.

C_c = Optional credit for removed connectors=0.67×net number (i.e., the total number of connectors removed minus the total added) of connectors in organic HAP service removed from the process unit after the applicability date set forth in §63.640(h)(4)(iii) for existing process units, and after the date of start-up for new process units. If credits are not taken, then $C_c = 0$.

(ii) Nonrepairable connectors shall be included in the calculation of percentage leaking connectors the first time the connector is identified as leaking and nonrepairable. Otherwise, a number of nonrepairable connectors up to a maximum of 1 percent per year of the total number of connectors in organic HAP service up to a maximum of 3 percent may be excluded from calculation of percentage leaking connectors for subsequent monitoring periods.

(iii) If the number of nonrepairable connectors exceeds 3 percent of the total number of connectors in organic HAP service, the number of nonrepairable connectors exceeding 3 percent of the total number shall be included in the calculation of the percentage leaking connectors.

(7) Physical tagging of the connectors to indicate that they are subject to the monitoring provisions is not required. Connectors may be identified by the area or length of pipe and need not be individually identified.

(d) *Subpart H program.* The owner or operator shall implement a program to comply with the provisions in §63.174 of this part.

(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.

(f) Any connector that is designated as an unsafe-to-repair connector is exempt from the requirements of paragraphs (b)(3) and (b)(4), (c)(3) and (c)(4), or (d) of this section if:

(1) The owner or operator determines that repair personnel would be exposed to an immediate danger as a consequence of complying with paragraphs (b)(3) and (b)(4), (c)(3) and (c)(4), of this section; or

(2) The connector will be repaired before the end of the next scheduled process unit shutdown.

(g) The owner or operator shall maintain records to document that the connector monitoring or inspections have been conducted as required and to document repair of leaking connectors as applicable.

§63.650 Gasoline loading rack provisions.

(a) Except as provided in paragraphs (b) through (c) of this section, each owner or operator of a Group 1 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) and (e), 63.425(a) through (c) and (i), 63.425(e) through (h), 63.427(a) and (b), and 63.428(b), (c), (g)(1), (h)(1) through (3), and (k).

(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).

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 74 FR 55685, Oct. 28, 2009]

§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 63.568.

(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 notification reports under §63.567(b) are 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).

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29880, June 12, 1996; 74 FR 55685, Oct. 28, 2009]

§63.652 Emissions averaging provisions.

(a) This section applies to owners or operators of existing sources who seek to comply with the emission standard in §63.642(g) by using emissions averaging according to §63.642(l) rather than following the provisions of §§63.643 through 63.647, and §§63.650 and 63.651. Existing marine tank vessel loading operations located at the Valdez Marine Terminal source may not comply with the standard by using emissions averaging.

(b) The owner or operator shall develop and submit for approval an Implementation Plan containing all of the information required in §63.653(d) for all points to be included in an emissions average. The Implementation Plan shall identify all emission points to be included in the emissions average. This must include any Group 1 emission points to which the reference control technology (defined in §63.641) is not applied and all other emission points being controlled as part of the average.

(c) The following emission points can be used to generate emissions averaging credits if control was applied after November 15, 1990 and if sufficient information is available to determine the appropriate value of credits for the emission point:

(1) Group 2 emission points;

(2) Group 1 storage vessels, Group 1 wastewater streams, Group 1 gasoline loading racks, Group 1 marine tank vessels, and Group 1 miscellaneous process vents that are controlled by a technology that the Administrator or permitting authority agrees has a higher nominal efficiency than the reference control technology. Information on the nominal efficiencies for such technologies must be submitted and approved as provided in paragraph (i) of this section; and

(3) Emission points from which emissions are reduced by pollution prevention measures. Percentages of reduction for pollution prevention measures shall be determined as specified in paragraph (j) of this section.

(i) For a Group 1 emission point, the pollution prevention measure must reduce emissions more than the reference control technology would have had the reference control technology been applied to the emission point instead of the pollution prevention measure except as provided in paragraph (c)(3)(ii) of this section.

(ii) If a pollution prevention measure is used in conjunction with other controls for a Group 1 emission point, the pollution prevention measure alone does not have to reduce emissions more than the reference control technology, but the combination of the pollution prevention measure and other controls must reduce emissions more than the reference control technology would have had it been applied instead.

(d) The following emission points cannot be used to generate emissions averaging credits:

(1) Emission points already controlled on or before November 15, 1990 unless the level of control is increased after November 15, 1990, in which case credit will be allowed only for the increase in control after November 15, 1990;

(2) Group 1 emission points that are controlled by a reference control technology unless the reference control technology has been approved for use in a different manner and a higher nominal efficiency has been assigned according to the procedures in paragraph (i) of this section. For example, it is not allowable to claim that an internal floating roof meeting only the specifications stated in the reference control technology definition in §63.641 (i.e., that meets the specifications of §63.119(b) of subpart G but does not have controlled fittings per §63.119 (b)(5) and (b)(6) of subpart G) applied to a storage vessel is achieving greater than 95 percent control;

(3) Emission points on shutdown process units. Process units that are shut down cannot be used to generate credits or debits;

(4) Wastewater that is not process wastewater or wastewater streams treated in biological treatment units. These two types of wastewater cannot be used to generate credits or debits. Group 1 wastewater streams cannot be left undercontrolled or uncontrolled to generate debits. For the purposes of this section, the terms “wastewater” and “wastewater stream” are used to mean process wastewater; and

(5) Emission points controlled to comply with a State or Federal rule other than this subpart, unless the level of control has been increased after November 15, 1990 above what is required by the other State or Federal rule. Only the control above what is required by the other State or Federal rule will be credited. However, if an emission point has been used to generate emissions averaging credit in an approved emissions average, and the point is subsequently made subject to a State or Federal rule other than this subpart, the point can continue to generate emissions averaging credit for the purpose of complying with the previously approved average.

(e) For all points included in an emissions average, the owner or operator shall:

(1) Calculate and record monthly debits for all Group 1 emission points that are controlled to a level less stringent than the reference control technology for those emission points. Equations in paragraph (g) of this section shall be used to calculate debits.

(2) Calculate and record monthly credits for all Group 1 or Group 2 emission points that are overcontrolled to compensate for the debits. Equations in paragraph (h) of this section shall be used to calculate credits. Emission points and controls that meet the criteria of paragraph (c) of this section may be included in the credit calculation, whereas those described in paragraph (d) of this section shall not be included.

(3) Demonstrate that annual credits calculated according to paragraph (h) of this section are greater than or equal to debits calculated for the same annual compliance period according to paragraph (g) of this section.

(i) The initial demonstration in the Implementation Plan that credit-generating emission points will be capable of generating sufficient credits to offset the debits from the debit-generating emission points must be made under representative operating conditions.

(ii) After the compliance date, actual operating data will be used for all debit and credit calculations.

(4) Demonstrate that debits calculated for a quarterly (3-month) period according to paragraph (g) of this section are not more than 1.30 times the credits for the same period calculated according to paragraph (h) of this section. Compliance for the quarter shall be determined based on the ratio of credits and debits from that quarter, with 30 percent more debits than credits allowed on a quarterly basis.

(5) Record and report quarterly and annual credits and debits in the Periodic Reports as specified in §63.655(g)(8). Every fourth Periodic Report shall include a certification of compliance with the emissions averaging provisions as required by §63.655(g)(8)(iii).

(f) Debits and credits shall be calculated in accordance with the methods and procedures specified in paragraphs (g) and (h) of this section, respectively, and shall not include emissions from the following:

(1) More than 20 individual emission points. Where pollution prevention measures (as specified in paragraph (j)(1) of this section) are used to control emission points to be included in an emissions average, no more than 25 emission points may be included in the average. For example, if two emission points to be included in an emissions average are controlled by pollution prevention measures, the average may include up to 22 emission points.

(2) Periods of startup, shutdown, and malfunction as described in the source's startup, shutdown, and malfunction plan required by §63.6(e)(3) of subpart A of this part.

(3) For emission points for which continuous monitors are used, periods of excess emissions as defined in §63.655(g)(6)(i). For these periods, the calculation of monthly credits and debits shall be adjusted as specified in paragraphs (f)(3)(i) through (f)(3)(iii) of this section.

(i) No credits would be assigned to the credit-generating emission point.

(ii) Maximum debits would be assigned to the debit-generating emission point.

(iii) The owner or operator may use the procedures in paragraph (l) of this section to demonstrate to the Administrator that full or partial credits or debits should be assigned.

(g) Debits are generated by the difference between the actual emissions from a Group 1 emission point that is uncontrolled or is controlled to a level less stringent than the reference control technology, and the emissions allowed for Group 1 emission point. Debits shall be calculated as follows:

(1) The overall equation for calculating sourcewide debits is:

$$Debits = \sum_{i=1}^{n}\left(EPV_{iACTUAL} - (0.02)\,EPV_{iu}\right) + \sum_{i=1}^{n}\left(ES_{iACTUAL} - (0.05)\,ES_{iu}\right) + \sum_{i=1}^{n}\left(EGLR_{iACTUAL} - EGLR_{iC}\right) + \sum_{i=1}^{n}\left(EMV_{iACTUAL} - (0.03)\,EMViu\right)$$

where:

Debits and all terms of the equation are in units of megagrams per month, and

$EPV_{iACTUAL}$ = Emissions from each Group 1 miscellaneous process vent i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(2) of this section.

(0.02) EPV_{iu} = Emissions from each Group 1 miscellaneous process vent i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (g)(2) of this section.

$ES_{iACTUAL}$ = Emissions from each Group 1 storage vessel i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(3) of this section.

(0.05) ES_{iu} = Emissions from each Group 1 storage vessel i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (g)(3) of this section.

$EGLR_{iACTUAL}$ = Emissions from each Group 1 gasoline loading rack i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(4) of this section.

$EGLR_{ic}$ = Emissions from each Group 1 gasoline loading rack i if the reference control technology had been applied to the uncontrolled emissions. This is calculated according to paragraph (g)(4) of this section.

EMV_{ACTUAL} = Emissions from each Group 1 marine tank vessel i that is uncontrolled or is controlled to a level less stringent than the reference control technology. This is calculated according to paragraph (g)(5) of this section.

(0.03) EMV_{iu} = Emissions from each Group 1 marine tank vessel i if the reference control technology had been applied to the uncontrolled emissions calculated according to paragraph (g)(5) of this section.

n=The number of Group 1 emission points being included in the emissions average. The value of n is not necessarily the same for each kind of emission point.

(2) Emissions from miscellaneous process vents shall be calculated as follows:

(i) For purposes of determining miscellaneous process vent stream flow rate, organic HAP concentrations, and temperature, the sampling site shall be after the final product recovery device, if any recovery devices are present; before any control device (for miscellaneous process vents, recovery devices shall not be considered control devices); and before discharge to the atmosphere. Method 1 or 1A of part 60, appendix A shall be used for selection of the sampling site.

(ii) The following equation shall be used for each miscellaneous process vent i to calculate EPV_{iu}:

$$EPV_{iu} = \left(2.494\times10^{-9}\right)Qh\left(\sum_{j=1}^{n}C_jM_j\right)$$

where:

EPV_{iu} = Uncontrolled process vent emission rate from miscellaneous process vent i, megagrams per month.

Q=Vent stream flow rate, dry standard cubic meters per minute, measured using Methods 2, 2A, 2C, or 2D of part 60 appendix A, as appropriate.

h=Monthly hours of operation during which positive flow is present in the vent, hours per month.

C_j = Concentration, parts per million by volume, dry basis, of organic HAP j as measured by Method 18 of part 60 appendix A.

M_j = Molecular weight of organic HAP j, gram per gram-mole.

n=Number of organic HAP's in the miscellaneous process vent stream.

(A) The values of Q, C_j, and M_j shall be determined during a performance test conducted under representative operating conditions. The values of Q, C_j, and M_j shall be established in the Notification of Compliance Status report and must be updated as provided in paragraph (g)(2)(ii)(B) of this section.

(B) If there is a change in capacity utilization other than a change in monthly operating hours, or if any other change is made to the process or product recovery equipment or operation such that the previously measured values of Q, C_j, and M_j are no longer representative, a new performance test shall be conducted to determine new representative values of Q, C_j, and M_j. These new values shall be used to calculate debits and credits from the time of the change forward, and the new values shall be reported in the next Periodic Report.

(iii) The following procedures and equations shall be used to calculate $EPV_{iACTUAL}$:

(A) If the vent is not controlled by a control device or pollution prevention measure, $EPV_{iACTUAL} = EPV_{iu}$, where EPV_{iu} is calculated according to the procedures in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(B) If the vent is controlled using a control device or a pollution prevention measure achieving less than 98-percent reduction,

$$EPV_{iACTUAL} = EPV_{iu}\times\left(1-\frac{Percent\ reduction}{100\%}\right)$$

(*1*) The percent reduction shall be measured according to the procedures in §63.116 of subpart G if a combustion control device is used. For a flare meeting the criteria in §63.116(a) of subpart G, or a boiler or process heater meeting the criteria in §63.645(d) of this subpart or §63.116(b) of subpart G, the percentage of reduction shall be 98 percent. If a noncombustion control device is used, percentage of reduction shall be demonstrated by a performance test at the inlet and outlet of the device, or, if testing is not feasible, by a control design evaluation and documented engineering calculations.

(*2*) For determining debits from miscellaneous process vents, product recovery devices shall not be considered control devices and cannot be assigned a percentage of reduction in calculating $EPV_{iACTUAL}$. The sampling site for measurement of uncontrolled emissions is after the final product recovery device.

(*3*) Procedures for calculating the percentage of reduction of pollution prevention measures are specified in paragraph (j) of this section.

(3) Emissions from storage vessels shall be calculated as specified in §63.150(g)(3) of subpart G.

(4) Emissions from gasoline loading racks shall be calculated as follows:

(i) The following equation shall be used for each gasoline loading rack i to calculate $EGLR_{iu}$:

$$EGLR_{iu} = \left(1.20 \times 10^{-7}\right) \frac{SPMG}{T}$$

where:

$EGLR_{iu}$ = Uncontrolled transfer HAP emission rate from gasoline loading rack i, megagrams per month

S=Saturation factor, dimensionless (see table 33 of subpart G).

P=Weighted average rack partial pressure of organic HAP's transferred at the rack during the month, kilopascals.

M=Weighted average molecular weight of organic HAP's transferred at the gasoline loading rack during the month, gram per gram-mole.

G=Monthly volume of gasoline transferred from gasoline loading rack, liters per month.

T=Weighted rack bulk liquid loading temperature during the month, degrees kelvin (degrees Celsius °C + 273).

(ii) The following equation shall be used for each gasoline loading rack i to calculate the weighted average rack partial pressure:

$$P = \frac{\sum_{1}^{j=n} \left(P_j\right)\left(G_j\right)}{G}$$

where:

P_j = Maximum true vapor pressure of individual organic HAP transferred at the rack, kilopascals.

G=Monthly volume of organic HAP transferred, liters per month, and

$$G = \sum_{1}^{j=n} G_j$$

G_j = Monthly volume of individual organic HAP transferred at the gasoline loading rack, liters per month.

n=Number of organic HAP's transferred at the gasoline loading rack.

(iii) The following equation shall be used for each gasoline loading rack i to calculate the weighted average rack molecular weight:

$$M = \frac{\sum_{1}^{j=n} \left(M_j\right)\left(G_j\right)}{G}$$

where:

M_j = Molecular weight of individual organic HAP transferred at the rack, gram per gram-mole.

G, G_j, and n are as defined in paragraph (g)(4)(ii) of this section.

(iv) The following equation shall be used for each gasoline loading rack i to calculate the monthly weighted rack bulk liquid loading temperature:

$$T = \frac{\sum_{1}^{j=n} (T_j)(G_j)}{G}$$

T_j = Average annual bulk temperature of individual organic HAP loaded at the gasoline loading rack, kelvin (degrees Celsius °C+273).

G, G_j, and n are as defined in paragraph (g)(4)(ii) of this section.

(v) The following equation shall be used to calculate $EGLR_{ic}$:

$$EGLR_{ic} = 1 \times 10^{-8} G$$

G is as defined in paragraph (g)(4)(ii) of this section.

(vi) The following procedures and equations shall be used to calculate $EGLR_{iACTUAL}$:

(A) If the gasoline loading rack is not controlled, $EGLR_{iACTUAL} = EGLR_{iu}$, where $EGLR_{iu}$ is calculated using the equations specified in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(B) If the gasoline loading rack is controlled using a control device or a pollution prevention measure not achieving the requirement of less than 10 milligrams of TOC per liter of gasoline loaded,

$$EGLR_{iACTUAL} = EGLR_{iu} \left(\frac{1 - Percent\ reduction}{100\%} \right)$$

(*1*) The percent reduction for a control device shall be measured according to the procedures and test methods specified in §63.128(a) of subpart G. If testing is not feasible, the percentage of reduction shall be determined through a design evaluation according to the procedures specified in §63.128(h) of subpart G.

(*2*) Procedures for calculating the percentage of reduction for pollution prevention measures are specified in paragraph (j) of this section.

(5) Emissions from marine tank vessel loading shall be calculated as follows:

(i) The following equation shall be used for each marine tank vessel i to calculate EMV_{iu}:

$$EMV_{iu} = \sum_{i=1}^{m} (Q_i)(F_i)(P_i)$$

where:

EMV_{iu} = Uncontrolled marine tank vessel HAP emission rate from marine tank vessel i, megagrams per month.

Q_i = Quantity of commodity loaded (per vessel type), liters.

F_i = Emission factor, megagrams per liter.

P_i = Percent HAP.

m=Number of combinations of commodities and vessel types loaded.

Emission factors shall be based on test data or emission estimation procedures specified in §63.565(l) of subpart Y.

(ii) The following procedures and equations shall be used to calculate $EMV_{iACTUAL}$:

(A) If the marine tank vessel is not controlled, $EMV_{iACTUAL} = EMV_{iu}$, where EMV_{iu} is calculated using the equations specified in paragraph (g)(5)(i) of this section.

(B) If the marine tank vessel is controlled using a control device or a pollution prevention measure achieving less than 97-percent reduction,

$$EMV_{iACTUAL} = EMV_{iu}\left(\frac{1-Percent\ reduction}{100\%}\right)$$

(*1*) The percent reduction for a control device shall be measured according to the procedures and test methods specified in §63.565(d) of subpart Y. If testing is not feasible, the percentage of reduction shall be determined through a design evaluation according to the procedures specified in §63.128(h) of subpart G.

(*2*) Procedures for calculating the percentage of reduction for pollution prevention measures are specified in paragraph (j) of this section.

(h) Credits are generated by the difference between emissions that are allowed for each Group 1 and Group 2 emission point and the actual emissions from a Group 1 or Group 2 emission point that has been controlled after November 15, 1990 to a level more stringent than what is required by this subpart or any other State or Federal rule or statute. Credits shall be calculated as follows:

(1) The overall equation for calculating sourcewide credits is:

$$\begin{aligned} Credits = {} & D\sum_{i=1}^{n}\left((0.02)\ \mathrm{EPV1}_{iu} - EPV1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(EPV2_{iBASE} - EPV2_{iACTUAL}\right) + \\ & D\sum_{i=1}^{n}\left((0.05)\ \mathrm{ES1}_{iu} - ES1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(ES2_{iBASE} - ES2_{iACTUAL}\right) + \\ & D\sum_{i=1}^{n}\left(\mathrm{EGLR}_{ic} - EGLR1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(EGLR2_{iBASE} - EGLR2_{iACTUAL}\right) + \\ & D\sum_{i=1}^{n}\left((0.03)\ \mathrm{EMV1}_{iu} - EMV1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(EMV2_{iBASE} - EMV2_{iACTUAL}\right) + \\ & D\sum_{i=1}^{n}\left(\mathrm{EWW1}_{ic} - EWW1_{iACTUAL}\right) + D\sum_{i=1}^{m}\left(EWW2_{iBASE} - EWW2_{iACTUAL}\right) \end{aligned}$$

where:

Credits and all terms of the equation are in units of megagrams per month, the baseline date is November 15, 1990, and

D=Discount factor=0.9 for all credit-generating emission points except those controlled by a pollution prevention measure, which will not be discounted.

$EPV1_{iACTUAL}$ = Emissions for each Group 1 miscellaneous process vent i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(2) of this section.

(0.02) $EPV1_{iu}$ = Emissions from each Group 1 miscellaneous process vent i if the reference control technology had been applied to the uncontrolled emissions. $EPV1_{iu}$ is calculated according to paragraph (h)(2) of this section.

$EPV2_{iBASE}$ = Emissions from each Group 2 miscellaneous process vent; at the baseline date, as calculated in paragraph (h)(2) of this section.

$EPV2_{iACTUAL}$ = Emissions from each Group 2 miscellaneous process vent that is controlled, calculated according to paragraph (h)(2) of this section.

$ES1_{iACTUAL}$ = Emissions from each Group 1 storage vessel i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(3) of this section.

(0.05) $ES1_{iu}$ = Emissions from each Group 1 storage vessel i if the reference control technology had been applied to the uncontrolled emissions. $ES1_{iu}$ is calculated according to paragraph (h)(3) of this section.

$ES2_{iACTUAL}$ = Emissions from each Group 2 storage vessel i that is controlled, calculated according to paragraph (h)(3) of this section.

$ES2_{iBASE}$ = Emissions from each Group 2 storage vessel i at the baseline date, as calculated in paragraph (h)(3) of this section.

$EGLR1_{iACTUAL}$ = Emissions from each Group 1 gasoline loading rack i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(4) of this section.

$EGLR_{ic}$ = Emissions from each Group 1 gasoline loading rack i if the reference control technology had been applied to the uncontrolled emissions. $EGLR_{iu}$ is calculated according to paragraph (h)(4) of this section.

$EGRL2_{iACTUAL}$ = Emissions from each Group 2 gasoline loading rack i that is controlled, calculated according to paragraph (h)(4) of this section.

$EGLR2_{iBASE}$ = Emissions from each Group 2 gasoline loading rack i at the baseline date, as calculated in paragraph (h)(4) of this section.

$EMV1_{iACTUAL}$ = Emissions from each Group 1 marine tank vessel i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(4) of this section.

(0.03)$EMV1_{iu}$ = Emissions from each Group 1 marine tank vessel i if the reference control technology had been applied to the uncontrolled emissions. $EMV1_{iu}$ is calculated according to paragraph (h)(5) of this section.

$EMV2_{iACTUAL}$ = Emissions from each Group 2 marine tank vessel i that is controlled, calculated according to paragraph (h)(5) of this section.

$EMV2_{iBASE}$ = Emissions from each Group 2 marine tank vessel i at the baseline date, as calculated in paragraph (h)(5) of this section.

$EWW1_{iACTUAL}$ = Emissions from each Group 1 wastewater stream i that is controlled to a level more stringent than the reference control technology, calculated according to paragraph (h)(6) of this section.

$EWW1_{ic}$ = Emissions from each Group 1 wastewater stream i if the reference control technology had been applied to the uncontrolled emissions, calculated according to paragraph (h)(6) of this section.

$EWW2_{iACTUAL}$ = Emissions from each Group 2 wastewater stream i that is controlled, calculated according to paragraph (h)(6) of this section.

$EWW2_{iBASE}$ = Emissions from each Group 2 wastewater stream i at the baseline date, calculated according to paragraph (h)(6) of this section.

n=Number of Group 1 emission points included in the emissions average. The value of n is not necessarily the same for each kind of emission point.

m=Number of Group 2 emission points included in the emissions average. The value of m is not necessarily the same for each kind of emission point.

(i) For an emission point controlled using a reference control technology, the percentage of reduction for calculating credits shall be no greater than the nominal efficiency associated with the reference control technology, unless a higher nominal efficiency is assigned as specified in paragraph (h)(1)(ii) of this section.

(ii) For an emission point controlled to a level more stringent than the reference control technology, the nominal efficiency for calculating credits shall be assigned as described in paragraph (i) of this section. A reference control technology may be approved for use in a different manner and assigned a higher nominal efficiency according to the procedures in paragraph (i) of this section.

(iii) For an emission point controlled using a pollution prevention measure, the nominal efficiency for calculating credits shall be determined as described in paragraph (j) of this section.

(2) Emissions from process vents shall be determined as follows:

(i) Uncontrolled emissions from miscellaneous process vents, $EPV1_{iu}$, shall be calculated according to the procedures and equation for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(ii) Actual emissions from miscellaneous process vents controlled using a technology with an approved nominal efficiency greater than 98 percent or a pollution prevention measure achieving greater than 98 percent emission reduction, $EPV1_{iACTUAL}$, shall be calculated according to the following equation:

$$EPV1_{iACTUAL} = EPV1_{iu}\left(1 - \frac{Nominal\ efficiency\ \%}{100\%}\right)$$

(iii) The following procedures shall be used to calculate actual emissions from Group 2 process vents, $EPV2_{iACTUAL}$:

(A) For a Group 2 process vent controlled by a control device, a recovery device applied as a pollution prevention project, or a pollution prevention measure, if the control achieves a percentage of reduction less than or equal to a 98 percent reduction,

$$EPV2_{iACTUAL} = EPV2_{iu} \times \left(1 - \frac{Percent\ reduction}{100\%}\right)$$

(*1*) $EPV2_{iu}$ shall be calculated according to the equations and procedures for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section except as provided in paragraph (h)(2)(iii)(A)(*3*) of this section.

(*2*) The percentage of reduction shall be calculated according to the procedures in paragraphs (g)(2)(iii)(B)(*1*) through (g)(2)(iii)(B)(*3*) of this section except as provided in paragraph (h)(2)(iii)(A)(*4*) of this section.

(*3*) If a recovery device was added as part of a pollution prevention project, $EPV2_{iu}$ shall be calculated prior to that recovery device. The equation for EPV_{iu} in paragraph (g)(2)(ii) of this section shall be used to calculate $EPV2_{iu}$; however, the sampling site for measurement of vent stream flow rate and organic HAP concentration shall be at the inlet of the recovery device.

(*4*) If a recovery device was added as part of a pollution prevention project, the percentage of reduction shall be demonstrated by conducting a performance test at the inlet and outlet of that recovery device.

(B) For a Group 2 process vent controlled using a technology with an approved nominal efficiency greater than a 98 percent or a pollution prevention measure achieving greater than 98 percent reduction,

$$EPV2_{iACTUAL} = EPV2_{iu}\left(1 - \frac{Nominal\ efficiency\ \%}{100\%}\right)$$

(iv) Emissions from Group 2 process vents at baseline, $EPV2_{iBASE}$, shall be calculated as follows:

(A) If the process vent was uncontrolled on November 15, 1990, $EPV2_{iBASE} = EPV2_{iu}$, and shall be calculated according to the procedures and equation for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section.

(B) If the process vent was controlled on November 15, 1990,

$$EPV2_{BASE} = EPV2_{iu}\left(1 - \frac{Percent\ reduction\ \%}{100\%}\right)$$

where $EPV2_{iu}$ is calculated according to the procedures and equation for EPV_{iu} in paragraphs (g)(2)(i) and (g)(2)(ii) of this section. The percentage of reduction shall be calculated according to the procedures specified in paragraphs (g)(2)(iii)(B)(*1*) through (g)(2)(iii)(B)(*3*) of this section.

(C) If a recovery device was added to a process vent as part of a pollution prevention project initiated after November 15, 1990, $EPV2_{iBASE} = EPV2_{iu}$, where $EPV2_{iu}$ is calculated according to paragraph (h)(2)(iii)(A)(*3*) of this section.

(3) Emissions from storage vessels shall be determined as specified in §63.150(h)(3) of subpart G, except as follows:

(i) All references to §63.119(b) in §63.150(h)(3) of subpart G shall be replaced with: §63.119 (b) or §63.119(b) except for §63.119(b)(5) and (b)(6).

(ii) All references to §63.119(c) in §63.150(h)(3) of subpart G shall be replaced with: §63.119(c) or §63.119(c) except for §63.119(c)(2).

(iii) All references to §63.119(d) in §63.150(h)(3) of subpart G shall be replaced with: §63.119(d) or §63.119(d) except for §63.119(d)(2).

(4) Emissions from gasoline loading racks shall be determined as follows:

(i) Uncontrolled emissions from Group 1 gasoline loading racks, $EGLR1_{iu}$, shall be calculated according to the procedures and equations for $EGLR_{iu}$ as described in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(ii) Emissions from Group 1 gasoline loading racks if the reference control technology had been applied, $EGLR_{ic}$, shall be calculated according to the procedures and equations in paragraph (g)(4)(v) of this section.

(iii) Actual emissions from Group 1 gasoline loading racks controlled to less than 10 milligrams of TOC per liter of gasoline loaded; $EGLR_{iACTUAL}$, shall be calculated according to the following equation:

$$EGLR1_{iACTUAL} = EGLR1_{iu}\left(1 - \frac{Nominal\ efficiency}{100\%}\right)$$

(iv) The following procedures shall be used to calculate actual emissions from Group 2 gasoline loading racks, $EGLR2_{iACTUAL}$:

(A) For a Group 2 gasoline loading rack controlled by a control device or a pollution prevention measure achieving emissions reduction but where emissions are greater than the 10 milligrams of TOC per liter of gasoline loaded requirement,

$$EGLR2_{iACTUAL} = EGLR2_{iu}\left(1 - \frac{Percent\ \text{reduction}}{100\%}\right)$$

(*1*) $EGLR2_{iu}$ shall be calculated according to the equations and procedures for $EGLR_{iu}$ in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(*2*) The percentage of reduction shall be calculated according to the procedures in paragraphs (g)(4)(vi)(B)(*1*) and (g)(4)(vi)(B)(*2*) of this section.

(B) For a Group 2 gasoline loading rack controlled by using a technology with an approved nominal efficiency greater than 98 percent or a pollution prevention measure achieving greater than a 98-percent reduction,

$$EGLR2_{iACTUAL} = EGLR2_{iu}\left(1 - \frac{\text{Nominal efficiency}}{100\%}\right)$$

(v) Emissions from Group 2 gasoline loading racks at baseline, $EGLR2_{iBASE}$, shall be calculated as follows:

(A) If the gasoline loading rack was uncontrolled on November 15, 1990, $EGLR2_{iBASE} = EGLR2_{iu}$, and shall be calculated according to the procedures and equations for $EGLR_{iu}$ in paragraphs (g)(4)(i) through (g)(4)(iv) of this section.

(B) If the gasoline loading rack was controlled on November 15, 1990,

$$EGLR2_{iBASE} = EGLR2_{iu}\left(1 - \frac{Percent\ \text{reduction}}{100\%}\right)$$

where $EGLR2_{iu}$ is calculated according to the procedures and equations for $EGLR_{iu}$ in paragraphs (g)(4)(i) through (g)(4)(iv) of this section. Percentage of reduction shall be calculated according to the procedures in paragraphs (g)(4)(vi)(B)(*1*) and (g)(4)(vi)(B)(*2*) of this section.

(5) Emissions from marine tank vessels shall be determined as follows:

(i) Uncontrolled emissions from Group 1 marine tank vessels, $EMV1_{iu}$, shall be calculated according to the procedures and equations for EMV_{iu} as described in paragraph (g)(5)(i) of this section.

(ii) Actual emissions from Group 1 marine tank vessels controlled using a technology or pollution prevention measure with an approved nominal efficiency greater than 97 percent, $EMV_{iACTUAL}$, shall be calculated according to the following equation:

$$EMV1_{iACTUAL} = EMV1_{iu}\left(1 - \frac{\text{Nominal efficiency}}{100\%}\right)$$

(iii) The following procedures shall be used to calculate actual emissions from Group 2 marine tank vessels, $EMV2_{iACTUAL}$:

(A) For a Group 2 marine tank vessel controlled by a control device or a pollution prevention measure achieving a percentage of reduction less than or equal to 97 percent reduction,

$$EMV2_{iACTUAL} = EMV2_{iu}\left(1 - \frac{\textit{Percent}\ \text{reduction}}{100\%}\right)$$

(*1*) $EMV2_{iu}$ shall be calculated according to the equations and procedures for EMV_{iu} in paragraph (g)(5)(i) of this section.

(*2*) The percentage of reduction shall be calculated according to the procedures in paragraphs (g)(5)(ii)(B)(*1*) and (g)(5)(ii)(B)(*2*) of this section.

(B) For a Group 2 marine tank vessel controlled using a technology or a pollution prevention measure with an approved nominal efficiency greater than 97 percent,

$$EMV2_{iACTUAL} = EMV2_{iu}\left(1 - \frac{\text{Nominal efficiency}}{100\%}\right)$$

(iv) Emissions from Group 2 marine tank vessels at baseline, $EMV2_{iBASE}$, shall be calculated as follows:

(A) If the marine terminal was uncontrolled on November 15, 1990, $EMV2_{iBASE}$ equals $EMV2_{iu}$, and shall be calculated according to the procedures and equations for EMV_{iu} in paragraph (g)(5)(i) of this section.

(B) If the marine tank vessel was controlled on November 15, 1990,

$$EMV2_{iBASE} = EMV2_{iu}\left(1 - \frac{\textit{Percent}\ \text{reduction}}{100\%}\right)$$

where $EMV2_{iu}$ is calculated according to the procedures and equations for EMV_{iu} in paragraph (g)(5)(i) of this section. Percentage of reduction shall be calculated according to the procedures in paragraphs (g)(5)(ii)(B)(*1*) and (g)(5)(ii)(B)(*2*) of this section.

(6) Emissions from wastewater shall be determined as follows:

(i) For purposes of paragraphs (h)(4)(ii) through (h)(4)(vi) of this section, the following terms will have the meaning given them in paragraphs (h)(6)(i)(A) through (h)(6)(i)(C) of this section.

(A) *Correctly suppressed* means that a wastewater stream is being managed according to the requirements of §§61.343 through 61.347 or §61.342(c)(l)(iii) of 40 CFR part 61, subpart FF, as applicable, and the emissions from the waste management units subject to those requirements are routed to a control device that reduces HAP emissions by 95 percent or greater.

(B) *Treatment process* has the meaning given in §61.341 of 40 CFR part 61, subpart FF except that it does not include biological treatment units.

(C) *Vapor control device* means the control device that receives emissions vented from a treatment process or treatment processes.

(ii) The following equation shall be used for each wastewater stream i to calculate EWW_{ic}:

$$EWW_{ic} = \left(6.0*10^{-8}\right) Q_i H_i \sum_{m=1}^{s} \left(1 - Fr_m\right) Fe_m HAP_{im} + \left(0.05\right)\left(6.0*10^{-8}\right) Q_i H_i \sum_{m=1}^{s} \left(Fr_m HAP_{im}\right)$$

where:

EWW_{ic} = Monthly wastewater stream emission rate if wastewater stream i were controlled by the reference control technology, megagrams per month.

Q_i = Average flow rate for wastewater stream i, liters per minute.

H_i = Number of hours during the month that wastewater stream i was generated, hours per month.

Fr_m = Fraction removed of organic HAP m in wastewater, from table 7 of this subpart, dimensionless.

Fe_m = Fraction emitted of organic HAP m in wastewater from table 7 of this subpart, dimensionless.

s=Total number of organic HAP's in wastewater stream i.

HAP_{im} = Average concentration of organic HAP m in wastewater stream i, parts per million by weight.

(A) HAP_{im} shall be determined for the point of generation or at a location downstream of the point of generation. Wastewater samples shall be collected using the sampling procedures specified in Method 25D of 40 CFR part 60, appendix A. Where feasible, samples shall be taken from an enclosed pipe prior to the wastewater being exposed to the atmosphere. 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 organic HAP's prior to sampling. The samples collected may be analyzed by either of the following procedures:

(*1*) A test method or results from a test method that measures organic HAP concentrations in the wastewater, and that has been validated pursuant to section 5.1 or 5.3 of Method 301 of appendix A of this part may be used; or

(*2*) Method 305 of appendix A of this part may be used to determine C_{im}, the average volatile organic HAP concentration of organic HAP m in wastewater stream i, and then HAP_{im} may be calculated using the following equation: $HAP_{im} = C_{im}/Fm_m$, where Fm_m for organic HAP m is obtained from table 7 of this subpart.

(B) Values for Q_i, HAP_{im}, and C_{im} shall be determined during a performance test conducted under representative conditions. The average value obtained from three test runs shall be used. The values of Q_i, HAP_{im}, and C_{im} shall be established in the Notification of Compliance Status report and must be updated as provided in paragraph (h)(6)(i)(C) of this section.

(C) If there is a change to the process or operation such that the previously measured values of Q_i, HAP_{im}, and C_{im} are no longer representative, a new performance test shall be conducted to determine new representative values of Q_i, HAP_{im}, and C_{im}. These new values shall be used to calculate debits and credits from the time of the change forward, and the new values shall be reported in the next Periodic Report.

(iii) The following equations shall be used to calculate $EWW1_{iACTUAL}$ for each Group 1 wastewater stream i that is correctly suppressed and is treated to a level more stringent than the reference control technology.

(A) If the Group 1 wastewater stream i is controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated HAP that is greater than that specified in table

7 of this subpart, and the vapor control device achieves a percentage of reduction equal to 95 percent, the following equation shall be used:

$$EWW1_{iACTUAL} = \left(6.0*10^{-8}\right) Q_i H_i \sum_{m=1}^{s} \left[Fe_m HAP_{im} \left(1 - PR_{im}\right)\right] + 0.05\left(6.0*10^{-8}\right) Q_i H_i \sum_{m=1}^{s} \left[HAP_{im} PR_{im} \right]$$

Where:

$EWW_{iACTUAL}$ = Monthly wastewater stream emission rate if wastewater stream i is treated to a level more stringent than the reference control technology, megagrams per month.

PR_{im} = The efficiency of the treatment process, or series of treatment processes, that treat wastewater stream i in reducing the emission potential of organic HAP m in wastewater, dimensionless, as calculated by:

$$PR_{im} = \frac{HAP_{im\text{-}in} - HAP_{im\text{-}out}}{HAP_{im\text{-}in}}$$

Where:

$HAP_{im\text{-}in}$ = Average concentration of organic HAP m, parts per million by weight, as defined and determined according to paragraph (h)(6)(ii)(A) of this section, in the wastewater entering the first treatment process in the series.

$HAP_{im\text{-}out}$ = Average concentration of organic HAP m, parts per million by weight, as defined and determined according to paragraph (h)(6)(ii)(A) of this section, in the wastewater exiting the last treatment process in the series.

All other terms are as defined and determined in paragraph (h)(6)(ii) of this section.

(B) If the Group 1 wastewater stream i is not controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated HAP that is greater than that specified in table 7 of this subpart, but the vapor control device has an approved nominal efficiency greater than 95 percent, the following equation shall be used:

$$EWW1_{iACTUAL} = \left(6.0*10^{-8}\right) Q_i H_i \sum_{m=1}^{s} \left[Fe_m HAP_{im} \left(1 - A_m\right)\right] + \left(1 - \frac{\text{Nominal efficiency \%}}{100}\right)\left(6.0*10^{-8}\right) Q_i H_i \sum_{m=1}^{s} \left[HAP_{im} A_m \right]$$

Where:

Nominal efficiency=Approved reduction efficiency of the vapor control device, dimensionless, as determined according to the procedures in §63.652(i).

A_m = The efficiency of the treatment process, or series of treatment processes, that treat wastewater stream i in reducing the emission potential of organic HAP m in wastewater, dimensionless.

All other terms are as defined and determined in paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(*1*) If a steam stripper meeting the specifications in the definition of reference control technology for wastewater is used, A_m shall be equal to the value of Fr_m given in table 7 of this subpart.

(*2*) If an alternative control device is used, the percentage of reduction must be determined using the equation and methods specified in paragraph (h)(6)(iii)(A) of this section for determining PR_{im}. If the value of PR_{im} is greater than or equal to the value of Fr_m given in table 7 of this subpart, then A_m equals Fr_m unless a higher nominal efficiency has been approved. If a higher nominal efficiency has been approved for the treatment process, the owner or operator shall determine $EWW1_{iACTUAL}$ according to paragraph (h)(6)(iii)(B) of this section rather than paragraph (h)(6)(iii)(A) of this section. If PR_{im} is less than the value of FR_m given in table 7 of this subpart, emissions averaging shall not be used for this emission point.

(C) If the Group 1 wastewater stream i is controlled using a treatment process or series of treatment processes with an approved nominal reduction efficiency for an individually speciated hazardous air pollutant that is greater than that specified in table 7 of this subpart, and the vapor control device has an approved nominal efficiency greater than 95 percent, the following equation shall be used:

$$EWW1_{iACTUAL} = \left(6.0*10^{-8}\right)Q_i H_i \sum_{m=1}^{s}\left[Fe_m HAP_{im}\left(1-PR_{im}\right)\right] + \left(1-\frac{\text{Nominal efficiency \%}}{100}\right)\left(6.0*10^{-8}\right)Q_i H_i \sum_{m=1}^{s}\left[HAP_{im} PR_{im}\right]$$

where all terms are as defined and determined in paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(iv) The following equation shall be used to calculate $EWW2_{iBASE}$ for each Group 2 wastewater stream i that on November 15, 1990 was not correctly suppressed or was correctly suppressed but not treated:

$$EWW2_{iBASE} = \left(6.0\times10^{-8}\right)Q_i H_i \sum_{m=1}^{s} Fe_m HAP_{im}$$

Where:

$EWW2_{iBASE}$ = Monthly wastewater stream emission rate if wastewater stream i is not correctly suppressed, megagrams per month.

Q_i, H_i, s, Fe_m, and HAP_{im} are as defined and determined according to paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(v) The following equation shall be used to calculate $EWW2_{iBASE}$ for each Group 2 wastewater stream i on November 15, 1990 was correctly suppressed. $EWW2_{iBASE}$ shall be calculated as if the control methods being used on November 15, 1990 are in place and any control methods applied after November 15, 1990 are ignored. However, values for the parameters in the equation shall be representative of present production levels and stream properties.

$$EWW2_{iBASE} = \left(6.0*10^{-8}\right)Q_i H_i \sum_{m=1}^{s}\left[Fe_m HAP_{im}\left(1-PR_{im}\right)\right] + \left(1-\frac{R_i}{100\%}\right)\left(6.0*10^{-8}\right)Q_i H_i \sum_{m=1}^{s}\left[HAP_{im} PR_{im}\right]$$

where R_i is calculated according to paragraph (h)(6)(vii) of this section and all other terms are as defined and determined according to paragraphs (h)(6)(ii) and (h)(6)(iii)(A) of this section.

(vi) For Group 2 wastewater streams that are correctly suppressed, $EWW2_{iACTUAL}$ shall be calculated according to the equation for $EWW2_{iBASE}$ in paragraph (h)(6)(v) of this section. $EWW2_{iACTUAL}$ shall be calculated with all control methods in place accounted for.

(vii) The reduction efficiency, R_i, of the vapor control device shall be demonstrated according to the following procedures:

(A) Sampling sites shall be selected using Method 1 or 1A of 40 CFR part 60, appendix A, as appropriate.

(B) The mass flow rate of organic compounds entering and exiting the control device shall be determined as follows:

(*1*) The time period for the test shall not be less than 3 hours during which at least three runs are conducted.

(*2*) A run shall consist of a 1-hour period during the test. For each run:

(*i*) The volume exhausted shall be determined using Methods 2, 2A, 2C, or 2D of 40 CFR part 60 appendix A, as appropriate;

(*ii*) The organic concentration in the vent stream entering and exiting the control device shall be determined using Method 18 of 40 CFR part 60, appendix A. Alternatively, any other test method validated according to the procedures in Method 301 of appendix A of this part may be used.

(*3*) The mass flow rate of organic compounds entering and exiting the control device during each run shall be calculated as follows:

$$E_a = \frac{0.0416}{10^6 \times m}\left[\sum_{p=1}^{m} V_{ap}\left(\sum_{p=1}^{n} C_{aip} MW_i\right)\right]$$

$$E_b = \frac{0.0416}{10^6 \times m}\left[\sum_{p=1}^{m} V_{bp}\left(\sum_{p=1}^{n} C_{bip} MW_i\right)\right]$$

Where:

E_a = Mass flow rate of organic compounds exiting the control device, kilograms per hour.

E_b = Mass flow rate of organic compounds entering the control device, kilograms per hour.

V_{ap} = Average volumetric flow rate of vent stream exiting the control device during run p at standards conditions, cubic meters per hour.

V_{bp} = Average volumetric flow rate of vent stream entering the control device during run p at standards conditions, cubic meters per hour.

p = Run.

m = Number of runs.

C_{aip} = Concentration of organic compound i measured in the vent stream exiting the control device during run p as determined by Method 18 of 40 CFR part 60 appendix A, parts per million by volume on a dry basis.

C_{bip} = Concentration of organic compound i measured in the vent stream entering the control device during run p as determined by Method 18 of 40 CFR part 60, appendix A, parts per million by volume on a dry basis.

MW_i = Molecular weight of organic compound i in the vent stream, kilograms per kilogram-mole.

n = Number of organic compounds in the vent stream.

0.0416 = Conversion factor for molar volume, kilograms-mole per cubic meter at 293 kelvin and 760 millimeters mercury absolute.

(C) The organic reduction efficiency for the control device shall be calculated as follows:

$$R = \frac{E_b - E_a}{E_b} \times 100$$

Where:

R = Total organic reduction efficiency for the control device, percentage.

E_b = Mass flow rate of organic compounds entering the control device, kilograms per hour.

E_a = Mass flow rate of organic compounds exiting the control device, kilograms per hour.

(i) The following procedures shall be followed to establish nominal efficiencies. The procedures in paragraphs (i)(1) through (i)(6) of this section shall be followed for control technologies that are different in use or design from the reference control technologies and achieve greater percentages of reduction than the percentages of efficiency assigned to the reference control technologies in §63.641.

(1) In those cases where the owner or operator is seeking permission to take credit for use of a control technology that is different in use or design from the reference control technology, and the different control technology will be used in more than three applications at a single plant site, the owner or operator shall submit the information specified in paragraphs (i)(1)(i) through (i)(1)(iv) of this section to the Administrator in writing:

(i) Emission stream characteristics of each emission point to which the control technology is or will be applied including the kind of emission point, flow, organic HAP concentration, and all other stream characteristics necessary to design the control technology or determine its performance;

(ii) Description of the control technology including design specifications;

(iii) Documentation demonstrating to the Administrator's satisfaction the control efficiency of the control technology. This may include performance test data collected using an appropriate EPA method or any other method validated according to Method 301 of appendix A of this part. If it is infeasible to obtain test data, documentation may include a design evaluation and calculations. The engineering basis of the calculation procedures and all inputs and assumptions made in the calculations shall be documented; and

(iv) A description of the parameter or parameters to be monitored to ensure that the control technology will be operated in conformance with its design and an explanation of the criteria used for selection of that parameter (or parameters).

(2) The Administrator shall determine within 120 calendar days whether an application presents sufficient information to determine nominal efficiency. The Administrator reserves the right to request specific data in addition to the items listed in paragraph (i)(1) of this section.

(3) The Administrator shall determine within 120 calendar days of the submittal of sufficient data whether a control technology shall have a nominal efficiency and the level of that nominal efficiency. If, in the Administrator's judgment, the control technology achieves a level of emission reduction greater than the reference control technology for a particular kind of emission point, the Administrator will publish a FEDERAL REGISTER notice establishing a nominal efficiency for the control technology.

(4) The Administrator may grant conditional permission to take emission credits for use of the control technology on requirements that may be necessary to ensure operation and maintenance to achieve the specified nominal efficiency.

(5) In those cases where the owner or operator is seeking permission to take credit for use of a control technology that is different in use or design from the reference control technology and the different control technology will be used in no more than three applications at a single plant site, the information listed in paragraphs (i)(1)(i) through (i)(1)(iv) of this section can be submitted to the permitting authority for the source for approval instead of the Administrator.

(i) In these instances, use and conditions for use of the control technology can be approved by the permitting authority. The permitting authority shall follow the procedures specified in paragraphs (i)(2) through (i)(4) of this section except that, in these instances, a FEDERAL REGISTER notice is not required to establish the nominal efficiency for the different technology.

(ii) If, in reviewing the submittal, the permitting authority believes the control technology has broad applicability for use by other sources, the permitting authority shall submit the information provided in the application to the Director of the EPA Office of Air Quality Planning and Standards. The Administrator shall review the technology for broad applicability and may publish a FEDERAL REGISTER notice; however, this review shall not affect the permitting authority's approval of the nominal efficiency of the control technology for the specific application.

(6) If, in reviewing an application for a control technology for an emission point, the Administrator or permitting authority determines the control technology is not different in use or design from the reference control technology, the Administrator or permitting authority shall deny the application.

(j) The following procedures shall be used for calculating the efficiency (percentage of reduction) of pollution prevention measures:

(1) A pollution prevention measure is any practice that meets the criteria of paragraphs (j)(1)(i) and (j)(1)(ii) of this section.

(i) A pollution prevention measure is any practice that results in a lesser quantity of organic HAP emissions per unit of product released to the atmosphere prior to out-of-process recycling, treatment, or control of emissions while the same product is produced.

(ii) Pollution prevention measures may include: Substitution of feedstocks that reduce HAP emissions, alterations to the production process to reduce the volume of materials released to the environment, equipment modifications; housekeeping measures, and in-process recycling that returns waste materials directly to production as raw materials. Production cutbacks do not qualify as pollution prevention.

(2) The emission reduction efficiency of pollution prevention measures implemented after November 15, 1990 can be used in calculating the actual emissions from an emission point in the debit and credit equations in paragraphs (g) and (h) of this section.

(i) For pollution prevention measures, the percentage of reduction used in the equations in paragraphs (g)(2) and (g)(3) of this section and paragraphs (h)(2) through (h)(4) of this section is the difference in percentage between the monthly organic HAP emissions for each emission point after the pollution prevention measure for the most recent month versus monthly emissions from the same emission point before the pollution prevention measure, adjusted by the volume of product produced during the two monthly periods.

(ii) The following equation shall be used to calculate the percentage of reduction of a pollution prevention measure for each emission point.

$$\text{Percent reduction} = \frac{E_B \frac{(E_{pp} \times P_B)}{P_{pp}}}{E_B} \times 100\%$$

Where:

Percent reduction=Efficiency of pollution prevention measure (percentage of organic HAP reduction).

E_B = Monthly emissions before the pollution prevention measure, megagrams per month, determined as specified in paragraphs (j)(2)(ii)(A), (j)(2)(ii)(B), and (j)(2)(ii)(C) of this section.

E_{pp} = Monthly emissions after the pollution prevention measure, megagrams per month, as determined for the most recent month, determined as specified in paragraphs (j)(2)(ii)(D) or (j)(2)(ii)(E) of this section.

P_B = Monthly production before the pollution prevention measure, megagrams per month, during the same period over which E_B is calculated.

P_{pp} = Monthly production after the pollution prevention measure, megagrams per month, as determined for the most recent month.

(A) The monthly emissions before the pollution prevention measure, E_B, shall be determined in a manner consistent with the equations and procedures in paragraphs (g)(2), (g)(3), (g)(4), and (g)(5) of this section for miscellaneous process vents, storage vessels, gasoline loading racks, and marine tank vessels.

(B) For wastewater, E_B shall be calculated as follows:

$$E_B = \sum_{i=1}^{n} \left[\left(6.0*10^{-8}\right) Q_{Bi}\, H_{Bi} \sum_{m=1}^{s} Fe_m HAP_{Bim} \right]$$

where:

n=Number of wastewater streams.

Q_{Bi} = Average flow rate for wastewater stream i before the pollution prevention measure, liters per minute.

H_{Bi} = Number of hours per month that wastewater stream i was discharged before the pollution prevention measure, hours per month.

s=Total number of organic HAP's in wastewater stream i.

Fe_m = Fraction emitted of organic HAP m in wastewater from table 7 of this subpart, dimensionless.

HAP_{Bim} = Average concentration of organic HAP m in wastewater stream i, defined and determined according to paragraph (h)(6)(ii)(A)(*2*) of this section, before the pollution prevention measure, parts per million by weight, as measured before the implementation of the pollution measure.

(C) If the pollution prevention measure was implemented prior to July 14, 1994, records may be used to determine E_B.

(D) The monthly emissions after the pollution prevention measure, E_{pp}, may be determined during a performance test or by a design evaluation and documented engineering calculations. Once an emissions-to-production ratio has been established, the ratio can be used to estimate monthly emissions from monthly production records.

(E) For wastewater, E_{pp} shall be calculated using the following equation:

$$E_{pp} = \sum_{i=1}^{n} \left[\left(6.0*10^{-8}\right) Q_{ppi}\, H_{ppi} \sum_{m=1}^{s} Fe_m HAP_{ppim} \right]$$

where n, Q, H, s, Fe_m, and HAP are defined and determined as described in paragraph (j)(2)(ii)(B) of this section except that Q_{ppi}, H_{ppi}, and HAP_{ppim} shall be determined after the pollution prevention measure has been implemented.

(iii) All equations, calculations, test procedures, test results, and other information used to determine the percentage of reduction achieved by a pollution prevention measure for each emission point shall be fully documented.

(iv) The same pollution prevention measure may reduce emissions from multiple emission points. In such cases, the percentage of reduction in emissions for each emission point must be calculated.

(v) For the purposes of the equations in paragraphs (h)(2) through (h)(6) of this section used to calculate credits for emission points controlled more stringently than the reference control technology, the nominal efficiency of a pollution prevention measure is equivalent to the percentage of reduction of the pollution prevention measure. When a pollution prevention measure is used, the owner or operator of a source is not required to apply to the Administrator for a nominal efficiency and is not subject to paragraph (i) of this section.

(k) The owner or operator shall demonstrate that the emissions from the emission points proposed to be included in the average will not result in greater hazard or, at the option of the State or local permitting authority, greater risk to human health or the environment than if the emission points were controlled according to the provisions in §§63.643 through 63.647, and §§63.650 and 63.651.

(1) This demonstration of hazard or risk equivalency shall be made to the satisfaction of the State or local permitting authority.

(i) The State or local permitting authority may require owners and operators to use specific methodologies and procedures for making a hazard or risk determination.

(ii) The demonstration and approval of hazard or risk equivalency may be made according to any guidance that the EPA makes available for use.

(2) Owners and operators shall provide documentation demonstrating the hazard or risk equivalency of their proposed emissions average in their Implementation Plan.

(3) An emissions averaging plan that does not demonstrate an equivalent or lower hazard or risk to the satisfaction of the State or local permitting authority shall not be approved. The State or local permitting authority may require such adjustments to the emissions averaging plan as are necessary in order to ensure that the average will not result in greater hazard or risk to human health or the environment than would result if the emission points were controlled according to §§63.643 through 63.647, and §§63.650 and 63.651.

(4) A hazard or risk equivalency demonstration shall:

(i) Be a quantitative, bona fide chemical hazard or risk assessment;

(ii) Account for differences in chemical hazard or risk to human health or the environment; and

(iii) Meet any requirements set by the State or local permitting authority for such demonstrations.

(l) For periods of excess emissions, an owner or operator may request that the provisions of paragraphs (l)(1) through (l)(4) of this section be followed instead of the procedures in paragraphs (f)(3)(i) and (f)(3)(ii) of this section.

(1) The owner or operator shall notify the Administrator of excess emissions in the Periodic Reports as required in §63.655(g)(6).

(2) The owner or operator shall demonstrate that other types of monitoring data or engineering calculations are appropriate to establish that the control device for the emission point was operating in such a fashion to warrant assigning full or partial credits and debits. This demonstration shall be made to the Administrator's satisfaction, and the Administrator may establish procedures for demonstrating compliance that are acceptable.

(3) The owner or operator shall provide documentation of the period of excess emissions and the other type of monitoring data or engineering calculations to be used to demonstrate that the control device for the emission point was operating in such a fashion to warrant assigning full or partial credits and debits.

(4) The Administrator may assign full or partial credit and debits upon review of the information provided.

[60 FR 43260, Aug. 18, 1995; 60 FR 49976, Sept. 27, 1995; 61 FR 7051, Feb. 23, 1996, as amended at 61 FR 29881, June 12, 1996; 61 FR 33799, June 28, 1996; 74 FR 55686, Oct. 28, 2009]

§63.653 Monitoring, recordkeeping, and implementation plan for emissions averaging.

(a) For each emission point included in an emissions average, the owner or operator shall perform testing, monitoring, recordkeeping, and reporting equivalent to that required for Group 1 emission points complying with §§63.643 through 63.647, and §§63.650 and 63.651. The specific requirements for miscellaneous process vents, storage vessels, wastewater, gasoline loading racks, and marine tank vessels are identified in paragraphs (a)(1) through (a)(7) of this section.

(1) The source shall implement the following testing, monitoring, recordkeeping, and reporting procedures for each miscellaneous process vent equipped with a flare, incinerator, boiler, or process heater:

(i) Conduct initial performance tests to determine the percentage of reduction as specified in §63.645 of this subpart and §63.116 of subpart G; and

(ii) Monitor the operating parameters specified in §63.644, as appropriate for the specific control device.

(2) The source shall implement the following procedures for each miscellaneous process vent, equipped with a carbon adsorber, absorber, or condenser but not equipped with a control device:

(i) Determine the flow rate and organic HAP concentration using the methods specified in §63.115 (a)(1) and (a)(2), §63.115 (b)(1) and (b)(2), and §63.115(c)(3) of subpart G; and

(ii) Monitor the operating parameters specified in §63.114 of subpart G, as appropriate for the specific recovery device.

(3) The source shall implement the following procedures for each storage vessel controlled with an internal floating roof, external roof, or a closed vent system with a control device, as appropriate to the control technique:

(i) Perform the monitoring or inspection procedures in §63.646 of this subpart and §63.120 of subpart G; and

(ii) For closed vent systems with control devices, conduct an initial design evaluation as specified in §63.646 of this subpart and §63.120(d) of subpart G.

(4) For each gasoline loading rack that is controlled, perform the testing and monitoring procedures specified in §§63.425 and 63.427 of subpart R of this part except §63.425(d) or §63.427(c).

(5) For each marine tank vessel that is controlled, perform the compliance, monitoring, and performance testing, procedures specified in §§63.563, 63.564, and 63.565 of subpart Y of this part.

(6) The source shall implement the following procedures for wastewater emission points, as appropriate to the control techniques:

(i) For wastewater treatment processes, conduct tests as specified in §61.355 of subpart FF of part 60;

(ii) Conduct inspections and monitoring as specified in §§61.343 through 61.349 and §61.354 of 40 CFR part 61, subpart FF.

(7) If an emission point in an emissions average is controlled using a pollution prevention measure or a device or technique for which no monitoring parameters or inspection procedures are specified in §§63.643 through 63.647 and §§63.650 and 63.651, the owner or operator shall establish a site-specific monitoring parameter and shall submit the information specified in §63.655(h)(4) in the Implementation Plan.

(b) Records of all information required to calculate emission debits and credits and records required by §63.655 shall be retained for 5 years.

(c) Notifications of Compliance Status report, Periodic Reports, and other reports shall be submitted as required by §63.655.

(d) Each owner or operator of an existing source who elects to comply with §63.655(g) and (h) by using emissions averaging for any emission points shall submit an Implementation Plan.

(1) The Implementation Plan shall be submitted to the Administrator and approved prior to implementing emissions averaging. This information may be submitted in an operating permit application, in an amendment to an operating permit application, in a separate submittal, in a Notification of Compliance Status Report, in a Periodic Report or in any combination of these documents. If an owner or operator submits the information specified in paragraph (d)(2) of this section at different times, and/or in different submittals, later submittals may refer to earlier submittals instead of duplicating the previously submitted information.

(2) The Implementation Plan shall include the information specified in paragraphs (d)(2)(i) through (d)(2)(ix) of this section for all points included in the average.

(i) The identification of all emission points in the planned emissions average and notation of whether each emission point is a Group 1 or Group 2 emission point as defined in §63.641.

(ii) The projected annual emission debits and credits for each emission point and the sum for the emission points involved in the average calculated according to §63.652. The annual projected credits must be greater than the projected debits, as required under §63.652(e)(3).

(iii) The specific control technology or pollution prevention measure that will be used for each emission point included in the average and date of application or expected date of application.

(iv) The specific identification of each emission point affected by a pollution prevention measure. To be considered a pollution prevention measure, the criteria in §63.652(j)(1) must be met. If the same pollution prevention measure reduces or eliminates emissions from multiple emission points in the average, the owner or operator must identify each of these emission points.

(v) A statement that the compliance demonstration, monitoring, inspection, recordkeeping, and reporting provisions in paragraphs (a), (b), and (c) of this section that are applicable to each emission point in the emissions average will be implemented beginning on the date of compliance.

(vi) Documentation of the information listed in paragraphs (d)(2)(vi)(A) through (d)(2)(vi)(D) of this section for each emission point included in the average.

(A) The values of the parameters used to determine whether each emission point in the emissions average is Group 1 or Group 2.

(B) The estimated values of all parameters needed for input to the emission debit and credit calculations in §63.652 (g) and (h). These parameter values or, as appropriate, limited ranges for the parameter values, shall be specified in the source's Implementation Plan as enforceable operating conditions. Changes to these parameters must be reported in the next Periodic Report.

(C) The estimated percentage of reduction if a control technology achieving a lower percentage of reduction than the efficiency of the reference control technology, as defined in §63.641, is or will be applied to the emission point.

(D) The anticipated nominal efficiency if a control technology achieving a greater percentage emission reduction than the efficiency of the reference control technology is or will be applied to the emission point. The procedures in §63.652(i) shall be followed to apply for a nominal efficiency.

(vii) The information specified in §63.655(h)(4) for:

(A) Each miscellaneous process vent controlled by a pollution prevention measure or control technique for which monitoring parameters or inspection procedures are not specified in paragraphs (a)(1) or (a)(2) of this section; and

(B) Each storage vessel controlled by a pollution prevention measure or a control technique other than an internal or external floating roof or a closed vent system with a control device.

(viii) Documentation of the information listed in paragraphs (d)(2)(viii)(A) through (d)(2)(viii)(G) of this section for each process wastewater stream included in the average.

(A) The information used to determine whether the wastewater stream is a Group 1 or Group 2 wastewater stream.

(B) The estimated values of all parameters needed for input to the wastewater emission credit and debit calculations in §63.652(h)(6).

(C) The estimated percentage of reduction if the wastewater stream is or will be controlled using a treatment process or series of treatment processes that achieves an emission reduction less than or equal to the emission reduction specified in table 7 of this subpart.

(D) The estimated percentage of reduction if a control technology achieving less than or equal to 95 percent emission reduction is or will be applied to the vapor stream(s) vented and collected from the treatment processes.

(E) The estimated percentage of reduction if a pollution prevention measure is or will be applied.

(F) The anticipated nominal efficiency if the owner or operator plans to apply for a nominal efficiency under §63.652(i). A nominal efficiency shall be applied for if:

(*1*) A control technology is or will be applied to the wastewater stream and achieves an emission reduction greater than the emission reduction specified in table 7 of this subpart; or

(*2*) A control technology achieving greater than 95 percent emission reduction is or will be applied to the vapor stream(s) vented and collected from the treatment processes.

(G) For each pollution prevention measure, treatment process, or control device used to reduce air emissions of organic HAP from wastewater and for which no monitoring parameters or inspection procedures are specified in §63.647, the information specified in §63.655(h)(4) shall be included in the Implementation Plan.

(ix) Documentation required in §63.652(k) demonstrating the hazard or risk equivalency of the proposed emissions average.

(3) The Administrator shall determine within 120 calendar days whether the Implementation Plan submitted presents sufficient information. The Administrator shall either approve the Implementation Plan, request changes, or request that the owner or operator submit additional information. Once the Administrator receives sufficient information, the Administrator shall approve, disapprove, or request changes to the plan within 120 calendar days.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29881, June 12, 1996; 63 FR 31361, June 9, 1998; 74 FR 55686, Oct. 28, 2009]

§63.654 Heat exchange systems.

(a) Except as specified in paragraph (b) of this section, the owner or operator of a heat exchange system that meets the criteria in §63.640(c)(8) must comply with the requirements of paragraphs (c) through (g) of this section.

(b) A heat exchange system is exempt from the requirements in paragraphs (c) through (g) of this section if all heat exchangers within the heat exchange system either:

(1) Operate with the minimum pressure on the cooling water side at least 35 kilopascals greater than the maximum pressure on the process side; or

(2) Employ an intervening cooling fluid containing less than 5 percent by weight of total organic HAP, as determined according to the provisions of §63.180(d) of this part and table 1 of this subpart, between the process and the cooling water. This intervening fluid must serve to isolate the cooling water from the process fluid and must not be sent through a cooling tower or discharged. For purposes of this section, discharge does not include emptying for maintenance purposes.

(c) The owner or operator must perform monitoring to identify leaks of total strippable volatile organic compounds (VOC) from each heat exchange system subject to the requirements of this subpart according to the procedures in paragraphs (c)(1) through (6) of this section.

(1) *Monitoring locations for closed-loop recirculation heat exchange systems.* For each closed loop recirculating heat exchange system, collect and analyze a sample from the location(s) described in either paragraph (c)(1)(i) or (c)(1)(ii) of this section.

(i) Each cooling tower return line or any representative riser within the cooling tower prior to exposure to air for each heat exchange system.

(ii) Selected heat exchanger exit line(s) so that each heat exchanger or group of heat exchangers within a heat exchange system is covered by the selected monitoring location(s).

(2) *Monitoring locations for once-through heat exchange systems.* For each once-through heat exchange system, collect and analyze a sample from the location(s) described in paragraph (c)(2)(i) of this section. The owner or operator may also elect to collect and analyze an additional sample from the location(s) described in paragraph (c)(2)(ii) of this section.

(i) Selected heat exchanger exit line(s) so that each heat exchanger or group of heat exchangers within a heat exchange system is covered by the selected monitoring location(s). The selected monitoring location may be at a point where discharges from multiple heat exchange systems are combined provided that the combined cooling water flow rate at the monitoring location does not exceed 40,000 gallons per minute.

(ii) The inlet water feed line for a once-through heat exchange system prior to any heat exchanger. If multiple heat exchange systems use the same water feed (*i.e.,* inlet water from the same primary water source), the owner or operator may monitor at one representative location and use the monitoring results for that sampling location for all heat exchange systems that use that same water feed.

(3) *Monitoring method.* Determine the total strippable hydrocarbon concentration (in parts per million by volume (ppmv) as methane) at each monitoring location using the "Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources" Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003 (incorporated by reference—see §63.14) using a flame ionization detector (FID) analyzer for on-site determination as described in Section 6.1 of the Modified El Paso Method.

(4) *Monitoring frequency and leak action level for existing sources.* For a heat exchange system at an existing source, the owner or operator must comply with the monitoring frequency and leak action level as defined in paragraph (c)(4)(i) of this section or comply with the monitoring frequency and leak action level as defined in paragraph (c)(4)(ii) of this section. The owner or operator of an affected heat exchange system may choose to comply with paragraph (c)(4)(i) of this section for some heat exchange systems at the petroleum refinery and comply with paragraph (c)(4)(ii) of this section for other heat exchange systems. However, for each affected heat exchange system, the owner or operator of an affected heat exchange system must elect one monitoring alternative that will apply at all times. If the owner or operator intends to change the monitoring alternative that applies to a heat exchange system, the owner or operator must notify the Administrator 30 days in advance of such a change. All "leaks" identified prior to changing monitoring alternatives must be repaired. The monitoring frequencies specified in paragraphs (c)(4)(i) and (ii) of this section also apply to the inlet water feed line for a once-through heat exchange system, if monitoring of the inlet water feed is elected as provided in paragraph (c)(2)(ii) of this section.

(i) Monitor monthly using a leak action level defined as a total strippable hydrocarbon concentration (as methane) in the stripping gas of 6.2 ppmv.

(ii) Monitor quarterly using a leak action level defined as a total strippable hydrocarbon concentration (as methane) in the stripping gas of 3.1 ppmv unless repair is delayed as provided in paragraph (f) of this section. If a repair is delayed as provided in paragraph (f) of this section, monitor monthly.

(5) *Monitoring frequency and leak action level for new sources.* For a heat exchange system at a new source, the owner or operator must monitor monthly using a leak action level defined as a total strippable hydrocarbon concentration (as methane) in the stripping gas of 3.1 ppmv.

(6) *Leak definition.* A leak is defined as described in paragraph (c)(6)(i) or (c)(6)(ii) of this section, as applicable.

(i) For once-through heat exchange systems for which the inlet water feed is monitored as described in paragraph (c)(2)(ii) of this section, a leak is detected if the difference in the measurement value of the sample taken from a location specified in paragraph (c)(2)(i) of this section and the measurement value of the corresponding sample taken from the location specified in paragraph (c)(2)(ii) of this section equals or exceeds the leak action level.

(ii) For all other heat exchange systems, a leak is detected if a measurement value of the sample taken from a location specified in either paragraph (c)(1)(i), (c)(1)(ii), or (c)(2)(i) of this section equals or exceeds the leak action level.

(d) If a leak is detected, the owner or operator must repair the leak to reduce the measured concentration to below the applicable action level as soon as practicable, but no later than 45 days after identifying the leak, except as specified in paragraphs (e) and (f) of this section. Repair includes re-monitoring at the monitoring location where the leak was identified according to the method specified in paragraph (c)(3) of this section to verify that the measured concentration is below the applicable action level. Actions that can be taken to achieve repair include but are not limited to:

(1) Physical modifications to the leaking heat exchanger, such as welding the leak or replacing a tube;

(2) Blocking the leaking tube within the heat exchanger;

(3) Changing the pressure so that water flows into the process fluid;

(4) Replacing the heat exchanger or heat exchanger bundle; or

(5) Isolating, bypassing, or otherwise removing the leaking heat exchanger from service until it is otherwise repaired.

(e) If the owner or operator detects a leak when monitoring a cooling tower return line under paragraph (c)(1)(i) of this section, the owner or operator may conduct additional monitoring of each heat exchanger or group of heat exchangers associated with the heat exchange system for which the leak was detected as provided under paragraph (c)(1)(ii) of this section. If no leaks are detected when monitoring according to the requirements of paragraph (c)(1)(ii) of this section, the heat exchange system is considered to meet the repair requirements through re-monitoring of the heat exchange system as provided in paragraph (d) of this section.

(f) The owner or operator may delay the repair of a leaking heat exchanger when one of the conditions in paragraph (f)(1) or (f)(2) of this section is met and the leak is less than the delay of repair action level specified in paragraph (f)(3) of this section. The owner or operator must determine if a delay of repair is necessary as soon as practicable, but no later than 45 days after first identifying the leak.

(1) If the repair is technically infeasible without a shutdown and the total strippable hydrocarbon concentration is initially and remains less than the delay of repair action level for all monthly monitoring periods during the delay of repair, the owner or operator may delay repair until the next scheduled shutdown of the heat exchange system. If, during subsequent monthly monitoring, the delay of repair action level is exceeded, the owner or operator must repair the leak within 30 days of the monitoring event in which the leak was equal to or exceeded the delay of repair action level.

(2) If the necessary equipment, parts, or personnel are not available and the total strippable hydrocarbon concentration is initially and remains less than the delay of repair action level for all monthly monitoring periods during

the delay of repair, the owner or operator may delay the repair for a maximum of 120 calendar days. The owner or operator must demonstrate that the necessary equipment, parts, or personnel were not available. If, during subsequent monthly monitoring, the delay of repair action level is exceeded, the owner or operator must repair the leak within 30 days of the monitoring event in which the leak was equal to or exceeded the delay of repair action level.

(3) The delay of repair action level is a total strippable hydrocarbon concentration (as methane) in the stripping gas of 62 ppmv. The delay of repair action level is assessed as described in paragraph (f)(3)(i) or (f)(3)(ii) of this section, as applicable.

(i) For once-through heat exchange systems for which the inlet water feed is monitored as described in paragraph (c)(2)(ii) of this section, the delay of repair action level is exceeded if the difference in the measurement value of the sample taken from a location specified in paragraph (c)(2)(i) of this section and the measurement value of the corresponding sample taken from the location specified in paragraph (c)(2)(ii) of this section equals or exceeds the delay of repair action level.

(ii) For all other heat exchange systems, the delay of repair action level is exceeded if a measurement value of the sample taken from a location specified in either paragraphs (c)(1)(i), (c)(1)(ii), or (c)(2)(i) of this section equals or exceeds the delay of repair action level.

(g) To delay the repair under paragraph (f) of this section, the owner or operator must record the information in paragraphs (g)(1) through (4) of this section.

(1) The reason(s) for delaying repair.

(2) A schedule for completing the repair as soon as practical.

(3) The date and concentration of the leak as first identified and the results of all subsequent monthly monitoring events during the delay of repair.

(4) An estimate of the potential strippable hydrocarbon emissions from the leaking heat exchange system or heat exchanger for each required delay of repair monitoring interval following the procedures in paragraphs (g)(4)(i) through (iv) of this section.

(i) Determine the leak concentration as specified in paragraph (c) of this section and convert the stripping gas leak concentration (in ppmv as methane) to an equivalent liquid concentration, in parts per million by weight (ppmw), using equation 7-1 from “Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources” Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003 (incorporated by reference—see §63.14) and the molecular weight of 16 grams per mole (g/mol) for methane.

(ii) Determine the mass flow rate of the cooling water at the monitoring location where the leak was detected. If the monitoring location is an individual cooling tower riser, determine the total cooling water mass flow rate to the cooling tower. Cooling water mass flow rates may be determined using direct measurement, pump curves, heat balance calculations, or other engineering methods. Volumetric flow measurements may be used and converted to mass flow rates using the density of water at the specific monitoring location temperature or using the default density of water at 25 degrees Celsius, which is 997 kilograms per cubic meter or 8.32 pounds per gallon.

(iii) For delay of repair monitoring intervals prior to repair of the leak, calculate the potential strippable hydrocarbon emissions for the leaking heat exchange system or heat exchanger for the monitoring interval by multiplying the leak concentration in the cooling water, ppmw, determined in (g)(4)(i) of this section, by the mass flow rate of the cooling water determined in (g)(4)(ii) of this section and by the duration of the delay of repair monitoring interval. The duration of the delay of repair monitoring interval is the time period starting at midnight on the day of the previous monitoring event or at midnight on the day the repair would have had to be completed if the repair had not been delayed, whichever is later, and ending at midnight of the day the of the current monitoring event.

(iv) For delay of repair monitoring intervals ending with a repaired leak, calculate the potential strippable hydrocarbon emissions for the leaking heat exchange system or heat exchanger for the final delay of repair monitoring interval by multiplying the duration of the final delay of repair monitoring interval by the leak concentration and cooling water flow rates determined for the last monitoring event prior to the re-monitoring event used to verify the leak was repaired. The duration of the final delay of repair monitoring interval is the time period starting at midnight of the day of the last monitoring event prior to re-monitoring to verify the leak was repaired and ending at the time of the re-monitoring event that verified that the leak was repaired.

[74 FR 55686, Oct. 28, 2009, as amended at 75 FR 37731, June 30, 2010; 78 FR 37146, June 20, 2013]

§63.655 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), (h)(1) through (h)(3), and (k) of subpart R. 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 §§63.567(a) and 63.567(c) through (k) of subpart Y. 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.

(ii) [Reserved]

(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)(vi) 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.

(vi) For each heat exchange system, identification of the heat exchange systems that are subject to the requirements of this subpart. For heat exchange systems at existing sources, the owner or operator shall indicate whether monitoring will be conducted as specified in §63.654(c)(4)(i) or §63.654(c)(4)(ii).

(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 (6) of this section or paragraph (g)(9) 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 identified in paragraph (g)(1) through (6) of this section or paragraph (g)(9) of this section occurred during the 6-month period unless emissions averaging is utilized. Quarterly reports must be submitted for emission points included in emission 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 (9) 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 reported by §63.567(e)(4) and (j)(3) of subpart Y 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.

(9) For heat exchange systems, Periodic Reports must include the following information:

(i) The number of heat exchange systems at the plant site subject to the monitoring requirements in §63.654.

(ii) The number of heat exchange systems at the plant site found to be leaking.

(iii) For each monitoring location where the total strippable hydrocarbon concentration was determined to be equal to or greater than the applicable leak definitions specified in §63.654(c)(6), identification of the monitoring location (e.g., unique monitoring location or heat exchange system ID number), the measured total strippable hydrocarbon concentration, the date the leak was first identified, and, if applicable, the date the source of the leak was identified;

(iv) For leaks that were repaired during the reporting period (including delayed repairs), identification of the monitoring location associated with the repaired leak, the total strippable hydrocarbon concentration measured during re-monitoring to verify repair, and the re-monitoring date (*i.e.*, the effective date of repair); and

(v) For each delayed repair, identification of the monitoring location associated with the leak for which repair is delayed, the date when the delay of repair began, the date the repair is expected to be completed (if the leak is not repaired during the reporting period), the total strippable hydrocarbon concentration and date of each monitoring event conducted on the delayed repair during the reporting period, and an estimate of the potential strippable hydrocarbon emissions over the reporting period associated with the delayed repair.

(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.

(7) The owner or operator of a heat exchange system at an existing source must notify the Administrator at least 30 calendar days prior to changing from one of the monitoring options specified in §63.654(c)(4) to the other.

(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 §63.655(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) The owner or operator of a heat exchange system subject to this subpart shall comply with the recordkeeping requirements in paragraphs (i)(4)(i) through (v) of this section and retain these records for 5 years.

(i) Identification of all petroleum refinery process unit heat exchangers at the facility and the average annual HAP concentration of process fluid or intervening cooling fluid estimated when developing the Notification of Compliance Status report.

(ii) Identification of all heat exchange systems subject to the monitoring requirements in §63.654 and identification of all heat exchange systems that are exempt from the monitoring requirements according to the provisions in §63.654(b). For each heat exchange system that is subject to the monitoring requirements in §63.654, this must include identification of all heat exchangers within each heat exchange system, and, for closed-loop recirculation systems, the cooling tower included in each heat exchange system.

(iii) Results of the following monitoring data for each required monitoring event:

(A) Date/time of event.

(B) Barometric pressure.

(C) El Paso air stripping apparatus water flow milliliter/minute (ml/min) and air flow, ml/min, and air temperature, °Celsius.

(D) FID reading (ppmv).

(E) Length of sampling period.

(F) Sample volume.

(G) Calibration information identified in Section 5.4.2 of the "Air Stripping Method (Modified El Paso Method) for Determination of Volatile Organic Compound Emissions from Water Sources" Revision Number One, dated January 2003, Sampling Procedures Manual, Appendix P: Cooling Tower Monitoring, prepared by Texas Commission on Environmental Quality, January 31, 2003 (incorporated by reference—see §63.14).

(iv) The date when a leak was identified, the date the source of the leak was identified, and the date when the heat exchanger was repaired or taken out of service.

(v) If a repair is delayed, the reason for the delay, the schedule for completing the repair, the heat exchange exit line flow or cooling tower return line average flow rate at the monitoring location (in gallons/minute), and the estimate of potential strippable hydrocarbon emissions for each required monitoring interval during the delay of repair.

(5) All other information required to be reported under paragraphs (a) through (h) of this section shall be retained for 5 years.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29881, June 12, 1996; 63 FR 44141, Aug. 18, 1998. Redesignated and amended at 74 FR 55686, 55687, Oct. 28, 2009; 75 FR 37731, June 30, 2010; 78 FR 37148, June 20, 2013]

§63.656 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, 63.646 through 63.652, and 63.654. 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.

[68 FR 37351, June 23, 2003. Redesignated and amended at 74 FR 55686, 55688, Oct. 28, 2009]

§§63.657-63.679 [Reserved]

Appendix to Subpart CC of Part 63—Tables

Table 1—Hazardous Air Pollutants

Chemical name	CAS No.[a]
Benzene	71432
Biphenyl	92524
Butadiene (1,3)	106990
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 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 2—Leak Definitions for Pumps and Valves

Standard[a]	Phase	Leak definition (parts per million)
§63.163 (pumps)	I	10,000
	II	5,000
	III	2,000
§63.168 (valves)	I	10,000
	II	1,000
	III	1,000

[a]Subpart H of this part.

Table 3—Equipment Leak Recordkeeping and Reporting Requirements for Sources Complying With §63.648 of Subpart CC by Compliance With Subpart H of this Part[a]

Reference (section of subpart H of this part)	Description	Comment
63.181(a)	Recordkeeping system requirements	Except for §§63.181(b)(2)(iii) and 63.181(b)(9).
63.181(b)	Records required for process unit equipment	Except for §§63.181(b)(2)(iii) and 63.181(b)(9).
63.181(c)	Visual inspection documentation	Except for §§63.181(b)(2)(iii) and 63.181(b)(9).
63.181(d)	Leak detection record requirements	Except for §63.181(d)(8).
63.181(e)	Compliance requirements for pressure tests for batch product process equipment trains	This subsection does not apply to subpart CC.
63.181(f)	Compressor compliance test records.	
63.181(g)	Closed-vent systems and control device record requirements.	
63.181(h)	Process unit quality improvement program records.	
63.181(i)	Heavy liquid service determination record.	
63.181(j)	Equipment identification record.	
63.181(k)	Enclosed-vented process unit emission limitation record requirements.	
63.182(a)	Reports.	
63.182(b)	Initial notification report requirements.	Not required.
63.182(c)	Notification of compliance status report	Except in §63.182(c); change “within 90 days of the compliance dates” to “within 150 days of the compliance dates”; except in §§63.182 (c)(2) and (c)(4).
63.182(d)	Periodic report	Except for §§63.182 (d)(2)(vii), (d)(2)(viii), and (d)(3).

[a]This table does not include all the requirements delineated under the referenced sections. See referenced sections for specific requirements.

Table 4—Gasoline Distribution Emission Point Recordkeeping and Reporting Requirements[a]

Reference (section of subpart R)	Description	Comment
63.428(b) or (k)	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 Operations Recordkeeping and Reporting Requirements[a]

Reference (section of subpart Y)	Description	Comment
63.562(e)(2)	Operation and maintenance plan for control equipment and monitoring equipment	
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)	Request for extension of compliance	
63.567(d)	Flare recordkeeping requirements	
63.567(e)	Summary report and excess emissions and monitoring system performance 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(f)	Vapor collection system engineering report	
63.567(g)	Vent system valve bypass recordkeeping requirements	
63.567(h)	Marine vessel vapor-tightness documentation	
63.567(i)	Documentation file maintenance	
63.567(j)	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)	Yes	
63.1(a)(5)	No	Reserved.
63.1(a)(6)	Yes	Except the correct mail drop (MD) number is C404-04.
63.1(a)(7)-63.1(a)(9)	No	Reserved.
63.1(a)(10)	Yes	
63.1(a)(11)	Yes	
63.1(a)(12)	Yes	
63.1(b)(1)	Yes	
63.1(b)(2)	No	Reserved.
63.1(b)(3)	No	
63.1(c)(1)	Yes	
63.1(c)(2)	No	Area sources are not subject to subpart CC.
63.1(c)(3)-63.1(c)(4)	No	Reserved.
63.1(c)(5)	Yes	Except that sources are not required to submit notifications overridden by this table.
63.1(d)	No	Reserved.
63.1(e)	No	No CAA section 112(j) standard applies to the affected sources under subpart CC.
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	Yes	
63.4(a)(1)-63.4(a)(2)	Yes	
63.4(a)(3)-63.4(a)(5)	No	Reserved.
63.4(b)	Yes	
63.4(c)	Yes	
63.5(a)	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).
63.5(b)(5)	No	Reserved.
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 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 §63.655(f) specifies Notification of Compliance Status report

Reference	Applies to subpart CC	Comment
		requirements.
63.5(d)(2)	Yes	
63.5(d)(3)	Yes	
63.5(d)(4)	Yes	
63.5(e)	Yes	
63.5(f)	Yes	
63.6(a)	Yes	
63.6(b)(1)-63.6(b)(5)	No	Subpart CC specifies compliance dates and notifications for sources subject to subpart CC.
63.6(b)(6)	No	Reserved.
63.6(b)(7)	Yes	
63.6(c)(1)-63.6(c)(2)	No	§63.640 of subpart CC specifies the compliance date.
63.6(c)(3)-63.6(c)(4)	No	Reserved.
63.6(c)(5)	Yes	
63.6(d)	No	Reserved.
63.6(e)(1)	Yes	Except the startup, shutdown, or malfunction plan does not apply to Group 2 emission points that are not part of an emissions averaging group.[b]
63.6(e)(2)	No	Reserved.
63.6(e)(3)(i)	Yes	Except the startup, shutdown, or malfunction plan does not apply to Group 2 emission points that are not part of an emissions averaging group.[b]
63.6(e)(3)(ii)	No	Reserved.
63.6(e)(3)(iii)-63.6(e)(3)(ix)	Yes	Except the reports specified in §63.6(e)(3)(iv) 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	Except for the heat exchange system standards, which apply at all times.
63.6(f)(2) and (3)	Yes	Except the phrase “as specified in §63.7(c)” in §63.6(f)(2)(iii)(D) does not apply because subpart CC does not require a site-specific test plan.
63.6(g)	Yes	
63.6(h)(1) and 63.6(h)(2)	Yes	Except §63.6(h)(2)(ii), which is reserved.
63.6(h)(3)	No	Reserved.
63.6(h)(4)	No	Notification of visible emission test not required in subpart CC.
63.6(h)(5)	No	Visible emission requirements and timing is specified in §63.645(i) of subpart CC.
63.6(h)(6)	Yes	
63.6(h)(7)	No	Subpart CC does not require opacity standards.
63.6(h)(8)	Yes	
63.6(h)(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)	Yes	
63.7(a)(2)	Yes	Except test results must be submitted in the Notification of Compliance Status report due 150 days after compliance date, as specified in §63.655(f) of subpart CC.
63.7(a)(3)	Yes	
63.7(a)(4)	Yes	

Reference	Applies to subpart CC	Comment
63.7(b)	No	Subpart CC requires notification of performance test at least 30 days (rather than 60 days) prior to the performance test.
63.7(c)	No	Subpart CC does not require a site-specific test plan.
63.7(d)	Yes	
63.7(e)(1)	Yes	Except the performance test must be conducted at the maximum representative capacity as specified in §63.642(d)(3) of subpart CC.
63.7(e)(2)- 63.7(e)(4)	Yes	
63.7(f)	No	Subpart CC specifies applicable methods and provides alternatives without additional notification or approval.
63.7(g)	No	Performance test reporting specified in §63.655(f).
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 §63.655(f).
63.7(h)(4)(i)	Yes	
63.7(h)(4)(ii)	No	Site-specific test plans are not required in subpart CC.
63.7(h)(4)(iii) and (iv)	Yes	
63.7(h)(5)	Yes	
63.8(a)	Yes	Except §63.8(a)(3), which is reserved.
63.8(b)	Yes	
63.8(c)(1)	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)	Yes	Except subpart CC specifies the monitoring cycle frequency specified in §63.8(c)(4)(ii) is “once every hour” rather than “for each successive 15-minute period.”
63.8(c)(5)- 63.8(c)(8)	No	
63.8(d)	No	
63.8(e)	No	Subpart CC does not require performance evaluations; however, this shall not abrogate the Administrator's authority to require performance evaluation under section 114 of the Clean Air Act.
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 §63.655(h)(5)(i) of subpart CC.
63.8(f)(4)(ii)	Yes	
63.8(f)(4)(iii)	No	Timeframe for submitting request is specified in §63.655(h)(5)(i) of subpart CC.
63.8(f)(5)	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 §63.655(i)(3).
63.9(a)	Yes	Except that the owner or operator does not need to send a copy of each notification

Reference	Applies to subpart CC	Comment
		submitted to the Regional Office of the EPA as stated in §63.9(a)(4)(ii).
63.9(b)(1)	Yes	Except the notification of compliance status report specified in §63.655(f) of subpart CC may also serve as the initial compliance notification required in §63.9(b)(1)(iii).
63.9(b)(2)	No	A separate Initial Notification report is not required under subpart CC.
63.9(b)(3)	No	Reserved.
63.9(b)(4)	Yes	Except for subparagraphs §63.9(b)(4)(ii) through (iv), which are reserved.
63.9(b)(5)	Yes	
63.9(c)	Yes	
63.9(d)	Yes	
63.9(e)	No	Subpart CC requires notification of performance test at least 30 days (rather than 60 days) prior to the performance test and does not require a site-specific test plan.
63.9(f)	No	Subpart CC does not require advanced notification of visible emissions test.
63.9(g)	No	
63.9(h)	No	Subpart CC §63.655(f) specifies Notification of Compliance Status report requirements.
63.9(i)	Yes	
63.9(j)	No	
63.10(a)	Yes	
63.10(b)(1)	No	§63.655(i) 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)	Yes	
63.10(b)(2)(vii)	No	
63.10(b)(2)(viii)	Yes	
63.10(b)(2)(ix)	Yes	
63.10(b)(2)(x)	Yes	
63.10(b)(2)(xi)	No	
63.10(b)(2)(xii)	Yes	
63.10(b)(2)(xiii)	No	
63.10(b)(2)(xiv)	Yes	
63.10(b)(3)	No	
63.10(c)(1)-63.10(c)(6)	No	
63.10(c)(7) and 63.10(c)(8)	Yes	
63.10(c)(9)-63.10(c)(15)	No	
63.10(d)(1)	Yes	
63.10(d)(2)	No	§63.655(f) of subpart CC specifies performance test reporting.
63.10(d)(3)	No	Results of visible emissions test are included in Compliance Status Report as specified in §63.655(f).
63.10(d)(4)	Yes	

Reference	Applies to subpart CC	Comment
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 §63.655(g) 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 and that cause the source to exceed any applicable emission limitation 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	
63.11-63.16	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 that are not part of an emissions averaging group.

Table 7—Fraction Measured (F_M), Fraction Emitted (F_E), and Fraction Removed (FR) for HAP Compounds in Wastewater Streams

Chemical name	CAS No.[a]	F_m	F_e	Fr
Benzene	71432	1.00	0.80	0.99
Biphenyl	92524	0.86	0.45	0.99
Butadiene (1,3)	106990	1.00	0.98	0.99
Carbon disulfide	75150	1.00	0.92	0.99
Cumene	98828	1.00	0.88	0.99
Dichloroethane (1,2-) (Ethylene dichloride)	107062	1.00	0.64	0.99
Ethylbenzene	100414	1.00	0.83	0.99
Hexane	110543	1.00	1.00	0.99
Methanol	67561	0.85	0.17	0.31
Methyl isobutyl ketone (hexone)	108101	0.98	0.53	0.99
Methyl tert butyl ether	1634044	1.00	0.57	0.99
Naphthalene	91203	0.99	0.51	0.99
Trimethylpentane (2,2,4)	540841	1.00	1.00	0.99
xylene (m-)	108383	1.00	0.82	0.99
xylene (o-)	95476	1.00	0.79	0.99
xylene (p-)	106423	1.00	0.82	0.99

[a]CAS numbers refer to the Chemical Abstracts Service registry number assigned to specific compounds, isomers, or mixtures of compounds.

Table 8—Valve Monitoring Frequency for Phase III

Performance level	Valve monitoring frequency
Leaking valves[a] (%)	
≥4	Monthly or QIP.[b]

Performance level Leaking valves[a] (%)	Valve monitoring frequency
<4	Quarterly.
<3	Semiannual.
<2	Annual.

[a]Percent leaking valves is calculated as a rolling average of two consecutive monitoring periods.

[b]QIP=Quality improvement program. Specified in §63.175 of subpart H of this part.

Table 9—Valve Monitoring Frequency for Alternative

Performance level Leaking valves[a] (%)	Valve monitoring frequency under §63.649 alternative
≥5	Monthly or QIP.[b]
<5	Quarterly.
<4	Semiannual.
<3	Annual.

[a]Percent leaking valves is calculated as a rolling average of two consecutive monitoring periods.

[b]QIP=Quality improvement program. Specified in §63.175 of subpart H of this part.

Table 10—Miscellaneous Process Vents—Monitoring, Recordkeeping and Reporting Requirements for Complying With 98 Weight-Percent Reduction of Total Organic HAP Emissions or a Limit of 20 Parts Per Million by Volume

Control device	Parameters to be monitored[a]	Recordkeeping and reporting requirements for monitored parameters
Thermal incinerator	Firebox temperature[b] (63.644(a)(1)(i))	1. Continuous records[c].
		2. Record and report the firebox temperature averaged over the full period of the performance test—NCS[d].
		3. Record the daily average firebox temperature for each operating day[e].
		4. Report all daily average temperatures that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected[f]—PR[g].
Catalytic incinerator	Temperature upstream and downstream of the catalyst bed (63.644(a)(1)(ii))	1. Continuous records[c].
		2. Record and report the upstream and downstream temperatures and the temperature difference across the catalyst bed averaged over the full period of the performance test—NCS[d].
		3. Record the daily average upstream temperature and temperature difference across the catalyst bed for each operating day[e].
		4. Report all daily average upstream temperatures that are outside the range established in the NCS or operating permit—PR[g].

Control device	Parameters to be monitored[a]	Recordkeeping and reporting requirements for monitored parameters
		5. Report all daily average temperature differences across the catalyst bed that are outside the range established in the NCS or operating permit—PR[g].
		6. Report all operating days when insufficient monitoring data are collected[f].
Boiler or process heater with a design heat capacity less than 44 megawatts where the vent stream is *not* introduced into the flame zone[h i]	Firebox temperature[b] (63.644(a)(4))	1. Continuous records[c].
		2. Record and report the firebox temperature averaged over the full period of the performance test—NCS[d].
		3. Record the daily average firebox temperature for each operating day[e].
		4. Report all daily average firebox temperatures that are outside the range established in the NCS or operating permit and all operating days when insufficient monitoring data are collected[f]—PR[g].
Flare	Presence of a flame at the pilot light (63.644(a)(2))	1. Hourly records of whether the monitor was continuously operating and whether a pilot flame was continuously present during each hour.
		2. Record and report the presence of a flame at the pilot light over the full period of the compliance determination—NCS[d].
		3. Record the times and durations of all periods when all pilot flames for a flare are absent or the monitor is not operating.
		4. Report the times and durations of all periods when all pilot flames for a flare are absent or the monitor is not operating.
All control devices	Presence of flow diverted to the atmosphere from the control device (63.644(c)(1)) *or*	1. Hourly records of whether the flow indicator was operating and whether flow was detected at any time during each hour.
		2. Record and report the times and durations of all periods when the vent stream is diverted through a bypass line or the monitor is not operating—PR[g].
	Monthly inspections of sealed valves [63.644(c)(2)]	1. Records that monthly inspections were performed.
		2. Record and report all monthly inspections that show the valves are not closed or the seal has been changed—PR[g].

[a]Regulatory citations are listed in parentheses.

[b]Monitor may be installed in the firebox or in the ductwork immediately downstream of the firebox before any substantial heat exchange is encountered.

[c]"Continuous records" is defined in §63.641.

[d]NCS = Notification of Compliance Status Report described in §63.655.

[e]The daily average is the average of all recorded parameter values for the operating day. If all recorded values during an operating day are within the range established in the NCS or operating permit, a statement to this effect can be recorded instead of the daily average.

[f]When a period of excess emission is caused by insufficient monitoring data, as described in §63.655(g)(6)(i)(C) or (D), the duration of the period when monitoring data were not collected shall be included in the Periodic Report.

[g]PR = Periodic Reports described in §63.655(g).

[h]No monitoring is required for boilers and process heaters with a design heat capacity ≥44 megawatts or for boilers and process heaters where all vent streams are introduced into the flame zone. No recordkeeping or reporting associated with monitoring is required for such boilers and process heaters.

[i]Process vents that are routed to refinery fuel gas systems are not regulated under this subpart. No monitoring, recordkeeping, or reporting is required for boilers and process heaters that combust refinery fuel gas.

[60 FR 43260, Aug. 18, 1995, as amended at 61 FR 29881, 29882, June 12, 1996; 63 FR 44142, 44143, Aug. 18, 1998; 74 FR 55688, Oct. 28, 2009; 75 FR 37731, June 30, 2010]

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Significant Source Modification

Source Description and Location

Source Name:	BP Products North America Inc., -- Whiting Business Unit
Source Location:	2815 Indianapolis Blvd., Whiting, IN 46394
County:	Lake
SIC Code:	2911 (Petroleum Refining)
Operation Permit No.:	T 089-30396-00453
Operation Permit Issuance Date:	December 8, 2014
Significant Source Modification No.:	089-35708-00453
Significant Permit Modification No.:	089-35729-00453
Permit Reviewer:	Doug Logan

Source Definition

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

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

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

(3) 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.

(b) The BP Whiting Refinery (BP) needs high pressure steam and high pressure hydrogen for its Whiting Refinery Modernization Project (WRMP). Praxair owns and operates a plant near the BP facility that produces low pressure hydrogen, carbon dioxide and low pressure steam (Plant A). Praxair's Plant A sells less than 50% of its current production to BP. In order to supply the high pressure hydrogen and high pressure steam needed for BP's WRMP, Praxair constructed a new plant (Plant B) near Plant A. IDEM, OAQ has examined whether Praxair's new Plant B will be part of the same major source as Praxair's Plant A, and whether one or both of the Praxair plants are part of the same major source as BP. The term "major source" is defined at 326 IAC 2-7-1(22). In order for two or more plants to be considered one major source, they must meet all three of the following criteria:

(1) the plants must be under common ownership or common control;

(2) the plants have the same two-digit SIC Code or one must serve as a support facility for another; and,

(3) the plants must be located on contiguous or adjacent properties.

The Two Praxair Plants

The first analysis will be of the relationship between the two Praxair plants. The Praxair plants are owned by Praxair. In 1996, IDEM adopted nonrule policy document (NPD) Air-005 to provide guidance for major source determinations. This nonrule policy states that if two plants are owned by the same entity, then common control exists. Since the two Praxair plants have the same owner, there is also common control and the first criterion of the definition of major source is met.

The SIC Code Manual, 1987, sets out how to determine the proper SIC Code for each type of business. The SIC Code is based on the source's primary activity or product. Although OSHA started using NAICS, the North American Industry Classification System, a 6-digit industry grouping system in 2003, Indiana's source definition rules still refer to the SIC Code Manual, 1987. OSHA keeps the Standard Industrial Classification Code Manual, 1987, available at http://www.osha.gov/pls/imis/sic_manual.html on the internet. The two Praxair plant have the same two-digit SIC code 28 for the major group Chemicals and Allied Products. The two plants therefore meet the second criterion of the definition.

The last criterion of the definition is whether the two plants are located on contiguous or adjacent properties. Praxair's Plant B is located approximately 75 yards from Praxair's Plant A. The plants are separated by property owned by Mittal Steel. A Mittal Steel bridge runs between the two Praxair properties. The two plants are not located on contiguous properties.

The term "adjacent" is not defined in Indiana's rules. NPD Air-005 adds the following guidance:

- properties that actually abut at any point would satisfy the requirement of contiguous or adjacent property.
- properties that are separated by a public road or public property would satisfy this requirement, absent special circumstances.
- other scenarios would be examined on an individual basis with the focus on the distance between the activities and the relationship between the activities.

All IDEM evaluations of adjacency are done on a case-by-case basis looking at the specific factors for the sources involved. The evaluation should look at whether the distance between the plants is sufficiently small that it enables them to operate as a single source. In addition to determining the distance between the sources, IDEM asks:

(1) Are materials routinely transferred between the plants?

(2) Do managers or other workers frequently shuttle back and forth to be involved actively in the plants?
(3) Is the production process itself split in any way between the plants?

These questions focus on whether the two separate sources are so interrelated that they are functioning as one plant, and whether the distance between them is small enough that it enables them to operate as one plant.

Praxair states that the site for Plant B was chosen because it was one of a very few possible sites in the area. Plant B must be located relatively close to BP to provide a cost effective way of supplying high pressure steam to BP's WRMP. Praxair has stated that it will not operate Plant B if the WRMP were to cease operation. Praxair has no customers for the additional 200 million cubic feet per day of high pressure hydrogen production or for the high pressure steam.

Materials will not be routinely transferred between the two Praxair sites. The only thing that will be transferred is low pressure steam produced at Plant A that is used as building heat for Plant B. Some of Plant B's piping will travel on Plant A's property but will not be directly connected to any process in Plant A.

The plant manager is the same for both the existing and new plant. Praxair uses the same plant manager for other Praxair sources that are in the same general area, even when the sources are miles apart. Praxair will employ additional regional employees with offices at Plant B that will have responsibilities at Plant A, Plant B and two other regional Praxair plants in Michigan. Praxair hired additional employees to operate Plant B. All Praxair employees located at Plant A and Plant B are cross-trained to perform tasks at either plant and all personnel are shared between the two plants. All employees at Plant A and Plant B may also be temporarily assigned to other Praxair plants in the region and elsewhere. Praxair uses this type of employee sharing companywide and would have used the same sharing arrangement even if Plant B had been located even further from Plant A.

Plant B will have its own control room, supply room, parts room and will function as a stand-alone plant. The production process will not be split in any way between the two Praxair plants. The raw materials Plant B will use to produce hydrogen and high pressure steam, natural gas, refinery gas and water, will come directly from BP.

The two Praxair plants do not operate as a single source. Though the plants will share one manager and production employees, they have separate and unrelated production processes. The plants could have the same relationship even if they were located many miles apart. Therefore, the two plants are not located on adjacent properties. Since they do not meet the third criteria of the major source definition, IDEM, OAQ finds that the two Praxair plants are not part of the same major source.

The Praxair Plants and the BP Whiting Refinery

IDEM, OAQ has also examined whether Praxair's Plant A and/or its new Plant B will be part of the same major source as BP. The same major source definition applies.

The Praxair plants have a different owner than BP and there is no other common owner. Where there is no common ownership, IDEM's NPD Air-005 sets out two tests to determine if common control exists. These are the two-pronged test and the but/for test. If either test is satisfied, then common control exists.

The two-pronged test examines if one of the sources is an auxiliary activity that directly serves the purpose of a primary activity and if the owner or operator of the primary activity has a major role in the day-to-day operations of the auxiliary activity. An auxiliary activity directly serves the purpose of a primary activity by supplying a necessary raw material to the primary activity or performing an integral part of the production process for the primary activity.

Day-to-day control of the auxiliary activity by the primary activity may be evidenced by several factors, including:

- is a majority of the output of the auxiliary activity provided to the primary activity?
- can the auxiliary activity contract to provide its products/services to a third-party without the consent of the primary activity?
- can the primary activity assume control of the auxiliary activity under certain circumstances?
- is the auxiliary activity required to provide periodic reports to the primary activity?

If one or a combination of these questions is answered affirmatively, common control may exist.

Plant A supplies hydrogen gas to BP. Plant A also produces hydrogen and carbon dioxide gases, which are sold to customers other than BP. More than 50% of Plant A's sales are to its other customers. BP does not have a major role in the day-to-day operations of Plant A. Plant A and BP do not meet the first common control test

Plant B will dedicate 92.5 percent of its total output of high pressure hydrogen and high pressure steam to BP. Plant B does not yet have any other customers. In addition, BP will supply all of the natural gas, refinery gas and water used by Plant B. BP will have a major role in the day-to-day operations of Plant B. Plant B and BP meet the first common control test.

The second common control test, the but/for test, asks if the auxiliary activity would exist absent the needs of the primary activity. If all or a majority of the output of the auxiliary activity is consumed by the primary activity the but/for test is satisfied.

If BP were to close, Plant A would be able to continue operating, since it will still have most of its customers and it does not get any material from BP. The but/for test is not satisfied. Therefore, there is no common control between Plant A and BP.

Plant B would lose at least 92.5% of its sales and lose its supply of essential raw materials if BP were to close. Plant B would not be able to operate until it created new fuel and water supply lines. Plant B would also have to find new customers. Plant B and BP satisfy the but/for test. Therefore, there is common control between Plant B and BP.

The second part of the definition of major source is whether the plants have the same two-digit SIC Code or if one serves as a support facility for the other. Plant A and Plant B have the two-digit SIC Code 28 for the major group Chemicals and Allied Products. BP has the two-digit SIC Code 29 for the major group Petroleum Refining and Related Industries.

A plant is considered a support facility if at least 50% of its total output is dedicated to the other plant. Plant A does not send 50% or more of its output to BP; therefore it is not a support facility. Plant B has dedicated at least 92.5% of its output to BP, so it is a support facility to BP. The second element of the definition is met for BP and Plant B, but not for BP and Plant A.

The last element of the definition is whether Plant A and/or Plant B are on contiguous or adjacent properties with BP. Plant A is on property that shares a common 40 foot long property line with BP's property. Therefore, Plant A and BP are on contiguous properties, meeting the third element of the definition.

Plant B is located on property that is not contiguous with BP's property. The two properties are about 1,600 feet apart. IDEM, OAQ must determine if Plant B and BP will be "adjacent". As stated above, all evaluations of adjacency are done on a case-by-case basis looking at the specific factors for the source involved. In addition to determining the distance between the sources, IDEM asks:

(1) Are materials routinely transferred between the plants?

(2) Do managers or other workers frequently shuttle back and forth to be involved actively in the plants?

(3) Is the production process itself split in any way between the plants?

These questions focus on whether the two separate sources are so interrelated that they are functioning as one plant, and that the distance between them is small enough that it enables them to operate as one

Refinery gas, natural gas and water will flow through lines from BP to Plant B. Plant B will use that fuel and raw material to create high pressure steam and hydrogen which will be sent to BP by other dedicated pipelines. It is important that Plant B is located near to BP for effective transmission of high pressure steam.

No managers or production staff will travel back and forth between Plant B and BP to be actively involved in both plants. The production process will be split between Plant B and BP, as the hydrogen and high pressure steam provided by Plant B will result in the production of additional refinery gas which can be sent to Plant B from BP.

IDEM, OAQ finds that the distance between the two plants is sufficiently small and their production processes are so intertwined that it allows them to function as one source. Therefore, Plant B and BP are located on adjacent properties.

Plant A and BP do not meet all three elements of the major source definition. Therefore, Plant A and BP are not part of the same major source. Plant B and BP meet all three elements of the definition. IDEM, OAQ therefore finds that Plant B and BP are part of the same major source.

Existing Approvals

The source was issued Part 70 Operating Permit No. 089-30396-00453 on December 8, 2014. The source has since received the following approvals:

(a) Administrative Amendment No. 089-35450-00453, issued on February 19, 2015

County Attainment Status

The source is located in Lake County.

Pollutant	Designation
SO_2	Better than national standards.
CO	Attainment effective February 18, 2000, for the part of the city of East Chicago bounded by Columbus Drive on the north; the Indiana Harbor Canal on the west; 148th Street, if extended, on the south; and Euclid Avenue on the east. Unclassifiable or attainment effective November 15, 1990, for the remainder of East Chicago and Lake County.
O_3	On June 11, 2012, the U.S. EPA designated Lake County nonattainment, for the 8-hour ozone standard. [1][2]
$PM_{2.5}$	Unclassifiable or attainment effective February 6, 2012, for the annual $PM_{2.5}$ standard.
$PM_{2.5}$	Unclassifiable or attainment effective December 13, 2009, for the 24-hour $PM_{2.5}$ standard.
PM_{10}	Attainment effective March 11, 2003, for the cities of East Chicago, Hammond, Whiting, and Gary. Unclassifiable effective November 15, 1990, for the remainder of Lake County.
NO_2	Cannot be classified or better than national standards.
Pb	Unclassifiable or attainment effective December 31, 2011.

[1]The U. S. EPA has acknowledged in both the proposed and final rulemaking for this redesignation that the anti-backsliding provisions for the 1-hour ozone standard no longer apply as a result of the redesignation under the 8-hour ozone standard. Therefore, permits in Lake County are no longer subject to review pursuant to Emission Offset, 326 IAC 2-3 for the 1-hour standard.
[2]The department has filed a legal challenge to U.S. EPA's designation in 77 FR 34228.

(a) Ozone Standards
U.S. EPA, in the Federal Register Notice 77 FR 112 dated June 11, 2012, has designated Lake County as nonattainment for ozone. On August 1, 2012, the air pollution control board issued an emergency rule adopting the U.S. EPA's designation. This rule became effective August 9, 2012. IDEM does not agree with U.S. EPA's designation of nonattainment. IDEM filed a suit against U.S. EPA in the U.S. Court of Appeals for the DC Circuit on July 19, 2012. 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 designation. Volatile organic compounds (VOC) and Nitrogen Oxides (NO_x) 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 NO_x emissions are considered when evaluating the rule applicability relating to ozone. Therefore, VOC and NO_x emissions were evaluated pursuant to the requirements of Emission Offset, 326 IAC 2-3.

(b) $PM_{2.5}$
Lake County has been classified as attainment for $PM_{2.5}$. Therefore, direct $PM_{2.5}$, SO_2, and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

(c) Other Criteria Pollutants
Lake County has been classified as attainment or unclassifiable in Indiana for all other criteria pollutants. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2.

Fugitive Emissions

Since this source is classified as a petroleum refinery it is considered one of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2, 326 IAC 2-3, or 326 IAC 2-7. Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

Source Status - Existing Source

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** (ton/yr)
PM	>100
PM_{10}	>100
$PM_{2.5}$	>100
SO_2	>100
NO_X	>100
VOC	>100
CO	>100
Single HAP	>10
Total HAP	>25

On June 23, 2014, in the case of *Utility Air Regulatory Group v. EPA*, cause no. 12-1146, (available at http://www.supremecourt.gov/opinions/13pdf/12-1146_4g18.pdf) the United States Supreme Court ruled that the U.S. EPA does not have the authority to treat greenhouse gases (GHGs) as an air pollutant for the purpose of determining operating permit applicability or PSD Major source status. On July 24, 2014, the U.S. EPA issued a memorandum to the Regional Administrators outlining next steps in permitting decisions in light of the Supreme Court's decision. U.S. EPA's guidance states that U.S. EPA will no longer require PSD or Title V permits for sources "previously classified as 'Major' based solely on greenhouse gas emissions."

The Indiana Environmental Rules Board adopted the GHG regulations required by U.S. EPA at 326 IAC 2-2-1(zz), pursuant to Ind. Code § 13-14-9-8(h) (Section 8 rulemaking). A rule, or part of a rule, adopted under Section 8 is automatically invalidated when the corresponding federal rule, or part of the rule, is invalidated. Due to the United States Supreme Court Ruling, IDEM, OAQ cannot consider GHGs emissions to determine operating permit applicability or PSD applicability to a source or modification.

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because a PSD regulated pollutant, excluding GHGs, 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(ff)(1).

(b) This existing source is a major stationary source, under Emission Offset (326 IAC 2-3), because VOC and NOx, nonattainment regulated pollutants, are each emitted at a rate of 100 tons per year or more.

(c) These emissions are based upon Part 70 Operating Permit Renewal T089-30396-0453.

(d) This existing source is a major source of HAPs, as defined in 40 CFR 63.2, 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).

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed a modification application, submitted by BP Products North America Inc., -- Whiting Business Unit on April 13, 2015, relating the following:

(1) The source has requested incorporating the requirements of the First Amendment to Consent Decree Civil No. 2:12-CV-207. .

(2) The source has also asked to install CEMS for NOx on the two Claus offgas treaters, TGU A and TGU B. TGU A and TGU B are collectively limited to 50.5 tons of NOx per twelve (12) consecutive month period. The permit currently imposes the following practically enforceable limits:

(a) The NO_X emissions from TGU A and TGU B each shall not exceed 0.08 pounds per million BTU.

(b) The Permittee shall comply with the following firing rate limit:

Unit ID	Firing Rate (10^3 mmBTU) per 12 consecutive month period
TGU A and TGU B (total)	1261.4

thus, Limited NOx emissions (tons/12 mo)
= 1,261.4E03 (MMBtu/12 mo) x 0.08 (lb/MMBtu) / 2,000 (lb/ton)
= 50.5 (tons NOx/12 mo)

In this modification, the source is not asking to change the ton per twelve (1) consecutive month limited NOx. Since compliance with the 12 month limit will be determined via CEMS, short term limits are not necessary and the NOx limit will be expressed in tons per 12 month.

Enforcement Issues

There are no pending enforcement actions related to this modification.

Emission Calculations

Emissions calculations are not included as part of this permitting action.

Permit Level Determination – Part 70 Modification to an Existing Source

There is no increase in the potential to emit of any regulated pollutants associated with this modification.

This source modification is subject to 326 IAC 2-7-10.5(b)(2) because it incorporates the requirements of a federal consent decree. 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 the modification requires significant changes in existing Part 70 monitoring permit terms and conditions.

Permit Level Determination – PSD or Emission Offset

There is no increase in potential to emit from this modification. Therefore the modification is not subject to PSD or Emission Offset.

TGU A and TGU B are collectively limited to 50.5 tons of NOx per twelve (12) consecutive month period. The permit currently imposes the following practically enforceable limits:

(a) The NO_X emissions from TGU A and TGU B each shall not exceed 0.08 pounds per million BTU.

(b) The Permittee shall comply with the following firing rate limit:

Unit ID	Firing Rate (10^3 mmBTU) per 12 consecutive month period
TGU A and TGU B (total)	1261.4

thus, Limited NOx emissions (tons/12 mo)
= 1,261.4E03 (MMBtu/12 mo) x 0.08 (lb/MMBtu) / 2,000 (lb/ton)
= 50.5 (tons NOx/12 mo)

In this modification, the source is not asking to change the ton per twelve (1) consecutive month limited NOx. Since compliance with the 12 month limit will be determined via CEMS, short term limits are not necessary and the NOx limit will be expressed in tons per 12 month.

Federal Rule Applicability Determination

The following federal rules are applicable to the source due to this modification:

NSPS:

(a) DEM, OAQ has reviewed the applicability of 40 CFR 60, Subpart QQQ, Standards of Performance for VOC Emissions From Petroleum Refinery Wastewater Systems to upgrades at the Hazardous Waste Treatment Facility and Wastewater Treatment Plant required by the Consent Decree filed in US et al vs. BP Products, Inc, 2:12-CV-00207, previously made in SSM 089-33530-00453, issued January 16, 2014 and SPM 089-33532-00453, issued February 4, 2014:

(1) Tanks TK-5050, TK-5051, TK-5052, and all equipment auxiliary and integral to the Oil Water Separators (including individual drain systems, the Tank Cleaning Dewatering System**,** and one (1) Solids Collection System, which vents to a dual carbon canister system and consists of the J-92 pump lift station and strainer backwash system, approved in 2014 for construction, with a storage capacity of 318,434 gallons, constructed as part of the Lakefront Upgrades Project) are still not subject to the requirements of the New Source Performance Standard for VOC Emissions From Petroleum Refinery Wastewater Systems, 40 CFR 60, Subpart QQQ, because the changes to the units do not result in an increase in emissions to the atmosphere. Therefore, the changes do not meet the definition of modification under 40 CFR 60.2.

(2) The DNF dewatering system, Dissolved Nitrogen Floatation (DNF) system, TK-562, and individual drain systems downstream of the oil-water separators are still not subject to the requirements of the New Source Performance Standard for VOC Emissions From Petroleum Refinery Wastewater Systems, 40 CFR 60, Subpart QQQ, because they are not considered affected facilities under 40 CFR 60.690 since they are located downstream from the oil-water separators. In addition, the changes to TK-562 do not result in an increase in emissions to the atmosphere.

This applicability review does not affect any requirements of Part 70 Operating Permit Renewal No.: 089-30396-00453, issued December 8, 2014.

NESHAP:

(b) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (326 IAC 14, 326 IAC 20 and 40 CFR Part 63) applicable to this proposed modification.

CAM:

(c) 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 Part 70 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.

Based on this evaluation, the requirements of 40 CFR Part 64, CAM are not applicable to any units as part of this modification because no units are beingmodified.

State Rule Applicability Determination

There are no state rules applicable to this proposed modification.

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 Requirements applicable to this modification are as follows:

(a) The Claus Offgas Treaters, TGU A and TGU B, have applicable compliance determination conditions as specified below:

(1) After the installation of the NOx continuous emission monitoring systems (CEMS) on TGU A, the CEMS shall be calibrated, maintained, and operated for measuring NOx in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment.

(2) After the installation of the NOx continuous emission monitoring systems (CEMS) on TGU B, the CEMS shall be calibrated, maintained, and operated for measuring NOx in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment.

Summary of Testing Requirements					
Emission Unit	**Control Device**	**Timeframe for Testing**	**Pollutant**	**Frequency of Testing**	**Authority**
Claus Offgas Treater, TGU A	none	180 days[1]	NOx	Once every 5 years[2]	326 IAC 2-7
Claus Offgas Treater, TGU B	none	180 days[1]	NOx	Once every 5 years[2]	326 IAC 2-7

Notes: 1. 180 days after startup of the TGU
2. Testing requirement continues only until installation of NOx CEMS on the TGU

The compliance monitoring requirements applicable to this modification are as follows:

(a) The Claus Offgas Treaters, TGU A and TGU B, have applicable compliance monitoring conditions as specified below:

(1) Whenever the NOx continuous emission monitoring system on the TGU A or TGU B is malfunctioning or will be down for calibration, maintenance, or repairs for more than twenty four (24) hours, the Permittee shall monitor and record stack percent oxygen to demonstrate that the operation of the unit continues in a typical manner. These parametric monitoring readings shall be recorded at least twice per day during normal operations, with at least four (4) hours between each set of readings, until the primary CEM or backup CEM is brought online.

These monitoring conditions are necessary because TGU A and TGU B must operate properly to ensure compliance with 326 IAC 2-1.1-4 (NSR), 326 IAC 2-2 (PSD), and 326 IAC 2-3 (Emission Offset).

Proposed Changes

The changes listed below have been made to Part 70 Operating Permit No. 089-30396-00453. Deleted language appears as ~~strikethroughs~~ and new language appears in **bold**:

Summary of Updates Throughout the Permit

(a) Descriptive information regarding the Claus Offgas Treaters, TGU A and TGU B.
(b) Revised RATA requirements for total sulfur analyzers in accordance with Modification #1 of the first amendment to the BP Whiting Consent Decree, Civil No. 2:12-CV-00207.

Section A - Revisions

(a) For clarity, IDEM, OAQ added the SIC code description to Condition A.1 - General Information.
(b) Section A has been revised to incorporate the appropriate updates detailed above under "Summary of Updates Throughout the Permit."

Section A has been revised as follows:

A.1 General Information [326 IAC 2-7-4(c)][326 IAC 2-7-5(14)][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
SIC Code:	2911 **(Petroleum Refining)**
County Location:	Lake
Source Location Status:	Nonattainment for 8-hr 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.3 Emission Units and Pollution Control Equipment Summary [326 IAC 2-7-4(c)(3)][326 IAC 2-7-5(14)]

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

(a) ...

(d) The Sulfur Recovery Plant (SRP), 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 WRMP Project, increasing the capacity to 1,300 long tons per day of sulfur. Additional sulfur capacity can be achieved with oxygen enrichment in the C, D and E Claus trains as part of the original WRMP design with no increase in permitted emissions. The facility includes the following and may also include insignificant activities listed in Section A.4 of this permit:

(1) ...

(18) Two (2) Claus Offgas Treaters (COT), identified as TGU A and TGU B, to be installed as part of the WRMP project, thermal oxidation systems which combust natural gas, each rated at 72 mmBTU/hr, **equipped with SO_2 and CO CEMS, and NOx CEMS approved in 2015 for installation,** exhausting at stacks S/V 162-06 and 162-07.

(19) ...

Section C - Revisions

(a) New paragraph l in Condition C.12 - Maintenance of Continuous Emission Monitoring Equipment has been added. Subsequent paragraphs are re-lettered.

Section C has been revised as follows:

...

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

(a) ...

(l) Whenever the NOx continuous emission monitoring system on the TGU A or TGU B is malfunctioning or will be down for calibration, maintenance, or repairs for more than twenty four (24) hours, the Permittee shall monitor and record stack percent oxygen 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.

(~~l~~**m)** ...

Section D.1 - Revisions

Section D.1 has been revised to incorporate the appropriate updates detailed above under "Summary of Updates Throughout the Permit."

Section D.1 has been revised as follows:

...

D.1.11 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in Heaters H-1X, H-2, H-3, H-200 and H-300. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ~~ASTM D3246-05~~ **EPA Methods 15A or 16C** shall be used as the reference method. **In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis.** Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) ...

Section D.2 - Revisions

Section D.2 has been revised to incorporate the appropriate updates detailed above under

"Summary of Updates Throughout the Permit."

Section D.2 has been revised as follows:

...

D.2.13 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in F-201, F-202 and F-203. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ~~ASTM D3246-05~~ **EPA Methods 15A or 16C** shall be used as the reference method. **In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis.** Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) ...

Section D.3 - Revisions

Section D.3 has been revised to incorporate the appropriate updates detailed above under "Summary of Updates Throughout the Permit."

Section D.3 has been revised as follows:

...

D.3.12 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in Heaters H-101A, H-101B and H-102. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ~~ASTM D3246-05~~ **EPA Methods 15A or 16C** shall be used as the reference method. **In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis.** Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) ...

Section D.4 - Revisions

(a) Paragraph (c)(5) in Condition D.4.4 - Prevention of Significant Deterioration has been updated to the current model language.
(b) A revised NOx limit in paragraph (c)(8) of Condition D.4.4 - Prevention of Significant Deterioration for TGU A and TGU B after installation of CEMS, expressing the limit as a value in tons per year has been added. Subsequent paragraphs were renumbered.
(c) Condition D.4.9 - Performance Testing Requirements has been revised to eliminate the requirement for NOx testing of TGU A and TGU B after installation of a NOx CEMS.
(d) Requirements for the NOx CEMS on TGU A and TGU B have been added to Condition D.4.12 - Continuous Emissions Monitoring.
(e) Paragraph (l) , (m), and (n) to Condition D.4.14 have been added to incorporate record keeping requirements for SO_2, CO, and firing rate, respectively, at TGU A and TGU B.
(f) Paragraph (o) has been added to Condition D.4.14 - Record Keeping Requirements to incorporate record keeping requirements for NOx at TGU A and TGU B that will become effective after installation of NOx CEMS. Subsequent paragraphs were relettered.
(g) Paragraph (f) in Condition D.4.15 - Reporting Requirements has been revised to clarify quarterly reporting for SO_2 emissions from TGU A and TGU B.
(h) Paragraphs (g) and (h) have been added to Condition D.4.15 - Reporting Requirements to clarify requirements for CO and firing rate.
(i) Paragraph (i) has been added to Condition D.4.15 - Reporting Requirements to incorporate requirements for NOx emissions from TGU A and TGU B that will become effective after installation of NOx CEMS. Subsequent paragraphs were relettered.
(j) Requirements for reporting excess NOx emissions have been added to paragraph (h) of Condition D.4.15 - Reporting Requirements.
(k) Section D.4 has been revised to incorporate the appropriate updates detailed above under "Summary of Updates Throughout the Permit."

Section D.4 has been revised as follows:

SECTION D.4 EMISSIONS UNIT OPERATION CONDITIONS - Sulfur Recovery Complex

Emissions Unit Description: (d) The Sulfur Recovery Plant (SRP), 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 WRMP Project, increasing the capacity to 1,300 long tons per day of sulfur. Additional sulfur capacity can be achieved with oxygen enrichment in the C, D and E Claus trains as part of the original WRMP design with no increase in permitted emissions. The facility includes the following and may also include insignificant activities listed in Section A.4 of this permit: (1) ... (18) Two (2) Claus Offgas Treaters (COT), identified as TGU A and TGU B, to be installed as part of the WRMP project, thermal oxidation systems which combust natural gas, each rated at 72 mmBTU/hr, equipped with SO_2 and CO CEMS, **and NOx CEMS approved in 2015 for installation,** exhausting at stacks S/V 162-06 and 162-07. (19) ... (The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

...

D.4.4 Prevention of Significant Deterioration [326 IAC 2-2], Nonattainment NSR and Emission Offset [326 IAC 2-3] Minor Limit

(a) ...

(c) In order to render 326 IAC 2-2, 326 IAC 2-1.1-4, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:
....

(5) The combined CO emissions from TGU A and TGU B shall not exceed 55.0 tons per **twelve (**12**)** consecutive month period, with compliance determined at the end of each month.

(6) ~~The~~ **Prior to the installation of the NOx CEMS on TGU A and TGU B, the** NO_X emissions from TGU A and TGU B each shall not exceed 0.08 pounds per million BTU.

(7) The Permittee shall comply with the following firing rate limit:

Unit ID	Firing Rate (10^3 mmBTU) per 12 consecutive month period
TGU A and TGU B (total)	1261.4

(8) After the installation of the NOx CEMS on TGU A and TGU B, the combined NOx emissions from TGU A and TGU B shall not exceed 50.5 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(~~8~~**9**) The B/S TGU, SBS TGU, and SBS Cooling tower shall be permanently shutdown prior to the completion of the WRMP project.

(~~9~~**10**) Pursuant to SSM 089-32033-00453, for all pumps involved in heavy liquid service, after the completion of the WRMP project, the Permittee shall control leaks of VOC from pumps according to the Leak Detection and Repair (LDAR) Plan submitted in accordance with Condition D.4.6. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Compliance with the limits on the annual firing rates and the NO_X, VOC, SO_2, 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 NO_X, VOC, SO_2, CO, PM and PM_{10} for the WRMP project remain below the significant, rendering 326 IAC 2-2, 326 IAC 2-1.1-4 and 326 IAC 2-3 not applicable for these pollutants.

...

D.4.9 Performance Testing Requirements [326 IAC 2-7-6(1), (6)] [326 IAC 2-1.1-11]

(a) Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the TGU A thermal oxidation system, the Permittee shall perform ~~NO_X,~~ PM, PM10 and VOC testing of TGU A utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(b) Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the TGU B thermal oxidation system, the Permittee shall perform ~~NO_X,~~ PM, PM10, and VOC testing of TGU B utilizing methods approved by the commissioner. This test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.

(c) **Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the TGU A thermal oxidation system, the Permittee shall perform NO_X testing of TGU A utilizing methods approved by the commissioner. Prior to the installation of the NOx CEMS on TGU A, this test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.**

(d) **Pursuant to SSM 089-32033-00453, not later than 180 days after the startup of the TGU B thermal oxidation system, the Permittee shall perform NO_X testing of TGU B utilizing methods approved by the commissioner. Prior to the installation of the NOx CEMS on TGU B, this test shall be repeated at least once every five (5) years from the date of the most recent valid compliance demonstration. Testing shall be conducted in accordance with the provisions of 326 IAC 3-6 (Source Sampling Procedures). Section C – Performance Testing contains the Permittee's obligation with regard to the performance testing required by this condition.**

...

D.4.12 Continuous Emissions Monitoring

(a) The CO continuous emission monitoring systems (CEMS) shall be calibrated, maintained, and operated for measuring CO in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment.

(b) **After the installation of the NOx continuous emission monitoring systems (CEMS) on TGU A, the CEMS shall be calibrated, maintained, and operated for measuring NOx in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment.**

(c) **After the installation of the NOx continuous emission monitoring systems (CEMS) on TGU B, the CEMS shall be calibrated, maintained, and operated for measuring NOx in accordance with the applicable requirements in Section C - Maintenance of Continuous Emission Monitoring Equipment and Section C - Maintenance of Emission Monitoring Equipment.**

...

D.4.14 Record Keeping Requirements

(a) ...

(i) Pursuant to 326 IAC 3-5-6 and to document the compliance status with Conditions D.4.10, D.4.11, **D.4.12,** C.12 and C.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) Nature of system repairs and adjustments.

...

(l) To document the compliance status with Condition D.4.4(c)(4), the Permittee shall maintain records of monthly SO_2 emissions for TGU A and TGU B.

(m) To document the compliance status with Condition D.4.4(c)(5), the Permittee shall maintain records of monthly CO emissions for TGU A and TGU B.

(n) To document the compliance status with Condition D.4.4(c)(7), the Permittee shall maintain records of monthly firing rate for TGU A and TGU B.

(o) After the installation of NOx CEMS on TGUA and TGU B, in order to document the compliance status with Condition D.4.4(c)(8), the Permittee shall maintain records of monthly NOx emissions for TGU A and TGU B.

(~~l~~**p**) Section C - General Record Keeping Requirements of this permit contains the Permittee's obligations with regard to the records required by Paragraphs (a), (b), (c), (d), (e), (f), (h), (i), ~~and~~ (k)**, (l), (m), (n), and (o)** of this condition.

D.4.15 Reporting Requirements

(a) ...

(f) ~~In order to document the compliance status with Condition D.4.4, upon~~ **Upon** start-up of TGU A and/or TGU B, ~~the Permittee shall submit a quarterly summary of the monthly firing rates and SO_2 and CO emissions at~~ **in order to document the compliance status with Condition D.4.4(c)(4), the Permittee shall submit a quarterly report of monthly emissions of SO_2 from TGU A and TGU B** not later than thirty (30) days after the end of the quarter being reported.

(g) Upon start-up of TGU A and/or TGU B, in order to document the compliance status with Condition D.4.4(c)(5), the Permittee shall submit a quarterly report of monthly emissions of CO from TGU A and TGU B not later than thirty (30) days after the end of each quarter.

(h) Upon start-up of TGU A and/or TGU B, in order to document the compliance status with Condition D.4.4(c)(7), the Permittee shall submit a quarterly report of monthly firing rates at TGU A and TGU B not later than thirty (30) days after the end of each quarter.

(i) Upon the installation of the NOx CEMS on TGU A and TGU B, in order to document the compliance status with Condition D.4.4(c)(8), the Permittee shall submit a quarterly report of monthly emissions of NOx from TGU A and TGU B not later than thirty (30) days after the end of each quarter.

(~~g~~**j**) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.4.4**,** D.4.10, D.4.11, **D.4.12,** C.12, and C.13, the Permittee shall submit reports of excess **NOX,** SO_2**,** and CO emissions at TGU A and TGU B not later than 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~~**k**) To document compliance with Condition D.4.6(b), the Permittee shall submit reports pursuant to 40 CFR 60, Subpart GGGa, as specified in Section F.9.

(~~i~~**l**) Section C - General Reporting Requirements contains the Permittee's obligation with regard to the reporting required by Paragraphs (a), (c), (d), (e), (f), (g), ~~and~~ (h)**, (i), (j), and (k)** of this condition. A quarterly report does require a certification that meets the requirements of 326 IAC 2-7-6(1) by a “responsible official” as defined by 326 IAC 2-7-1(35).

Section D.9 - Revisions

Section D.9 has been revised to incorporate the appropriate updates detailed above under "Summary of Updates Throughout the Permit."

Section D.9 has been revised as follows:

...

D.9.10 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in the H-1 Heater. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ~~ASTM D3246-05~~ **EPA Methods 15A or 16C** shall be used as the reference method. **In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis.** Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) ...

Section D.10 - Revisions

Section D.10 has been revised to incorporate the appropriate updates detailed above under "Summary of Updates Throughout the Permit."

Section D.10 has been revised as follows:

...

D.10.10 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in ARU Heaters F-200A and F-200B. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ~~ASTM D3246-05~~ **EPA Methods 15A or 16C** shall be used as the reference method. **In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis.** Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) ...

Section D.11 - Revisions

Section D.11 has been revised to incorporate the appropriate updates detailed above under "Summary of Updates Throughout the Permit."

Section D.11 has been revised as follows:

...

D.11.10 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in BOU Heater F-401. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ~~ASTM D3246-05~~ **EPA Methods 15A or 16C** shall be used as the reference method. **In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis.** Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR

§ 60.107a(a)(3).

(b) ...

Section D.16 - Revisions

Section D.16 has been revised to incorporate the appropriate updates detailed above under "Summary of Updates Throughout the Permit."

Section D.16 has been revised as follows:

...

D.16.10 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in 4UF Heaters F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A and F-8B. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ~~ASTM D3246-05~~ **EPA Methods 15A or 16C** shall be used as the reference method. **In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis.** Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) ...

Section D.17 - Revisions

Section D.17 has been revised to incorporate the appropriate updates detailed above under "Summary of Updates Throughout the Permit."

Section D.17 has been revised as follows:

...

D.17.11 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in Heater B-501. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ~~ASTM D3246-05~~ **EPA Methods 15A or 16C** shall be used as the reference method. **In**

addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis. Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) ...

Section D.18 - Revisions

Section D.18 has been revised to incorporate the appropriate updates detailed above under "Summary of Updates Throughout the Permit."

Section D.18 has been revised as follows:

...

D.18.11 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in DDU Heaters B-301 and B-302. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ~~ASTM D3246-05~~ **EPA Methods 15A or 16C** shall be used as the reference method. **In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis.** Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) ...

Section D.19 - Revisions

Section D.19 has been revised to incorporate the appropriate updates detailed above under "Summary of Updates Throughout the Permit."

Section D.19 has been revised as follows:

...

D.19.11 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in Heaters F-801A, F-801B and F-801C. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ~~ASTM D3246-05~~ **EPA Methods 15A or 16C** shall be used as the reference method. **In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis.** Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) ...

Section D.20 - Revisions

Section D.20 has been revised to incorporate the appropriate updates detailed above under "Summary of Updates Throughout the Permit."

Section D.20 has been revised as follows:

...

D.20.11 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in Heaters F-101 and F-102A. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ~~ASTM D3246-05~~ **EPA Methods 15A or 16C** shall be used as the reference method. **In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis.** Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) ...

Section D.24 - Revisions

Section D.24 has been revised to incorporate the appropriate updates detailed above under "Summary of Updates Throughout the Permit."

Section D.24 has been revised as follows:

...

D.24.12 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in

Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in the No. 3 SPS Boilers 31, 32, 33, 34, and 36 and the five (5) duct burners. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ~~ASTM D3246-05~~ **EPA Methods 15A or 16C** shall be used as the reference method. **In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis.** Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) ...

Section D.35 - Revisions

The timing for tie-in of Alky and UIU flares to flare gas recovery has been revised in accordance with Modification #9 of the first amendment to the BP Whiting Consent Decree, Civil No. 2:12-CV-00207.

Section D.35 has been revised as follows:

...

D.35.8 Consent Decree (Civil No. 2:12-CV-00207) Requirements

...

D. Flare Gas Recovery Systems for all Covered Flares Except the DDU Flare

23. Dates of Installation and Commencement of Operation of Flare Gas Recovery Systems

a. Except as specifically provided in Subparagraph 23.b, by no later than the following dates for the following Covered Flares or groups of Covered Flares, BPP shall complete installation and commence operation of the following Flare Gas Recovery Systems:

ID	Covered Flares	Date
FGRS 1	South Flare	Upon startup of South Flare
FGRS 2	GOHT	Upon startup of GOHT Flare
FGRS 3	VRU, FCU, Alky	December 31, 2015
FGRS 4	4UF, UIU	December 31, 2016

b. BPP shall complete the tie-in of the ~~UIU~~ **Alky** Flare to FGRS 4**3** by no later than December 31, 201~~7~~**6**, and commence recovery of Waste Gas by that time.

Note: This Paragraph (D.23.a) was not required to be placed in a Part 70 operating permit pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207; however, the requirement is specified in the Consent Decree entered in Civil No. 2:12-CV-00207.

25. ...

Section D.42 - Revisions

Section D.42 has been revised to incorporate the appropriate updates detailed above under "Summary of IDEM Updates Throughout the Permit."

Section D.42 has been revised as follows:

...

D.42.9 Continuous Emissions Monitoring

(a) Pursuant to SSM 089-32033-00453 and as specified by the Consent Decree entered in Civil No. 2:12-CV-00207, by December 31, 2013, the Permittee shall install Total Sulfur Continuous Analyzers on the refinery fuel gas systems to continuously monitor, measure and record the total sulfur concentration of fuel gas burned in GOHT Heaters F-901A and F-901B. The Total Sulfur Continuous Analyzers shall be installed, operated and calibrated pursuant to ASTM D7166-10 and 40 CFR Part 60 Appendices A and F, and the applicable performance specification test of 40 CFR Part 60 Appendix B, except that in lieu of the requirements of 40 CFR Part 60, Appendix F §§ 5.1.1, 5.1.3 and 5.1.4, the Permittee must conduct a Relative Accuracy Audit (RAA) or a Relative Accuracy Test Audit (RATA) on each Total Sulfur Continuous Analyzer at least once every three (3) years. The Permittee must also conduct Cylinder Gas Audits each Calendar Quarter during which a RAA or a RATA is not performed. For RATA and RAA reference method comparisons, ~~ASTM D3246-05~~ **EPA Methods 15A or 16C** shall be used as the reference method. **In addition, the Permittee may also use the principles of EPA Method 7E, section 8.3 to dilute the fuel gas samples used for the reference method as necessary to render the samples safe for analysis.** Consistent with 40 CFR § 60.107a(a)(2)(iv), the Permittee shall monitor refinery fuel gas at locations that accurately represent the total sulfur concentration in the refinery fuel gas being burned in all heaters and boilers in the refinery, other than refinery fuel gas that would be exempt from monitoring under 40 CFR § 60.107a(a)(3).

(b) ...

Conclusion and Recommendation

The construction and operation of this proposed modification shall be subject to the conditions of the attached proposed Part 70 Significant Source Modification No. 089-35708-00453 and Significant Permit Modification No. 089-35729-00453. The staff recommend to the Commissioner that this Part 70 Significant Source Modification and Significant Permit Modification be approved.

IDEM Contact

(a) Questions regarding this proposed permit can be directed to Doug Logan at the Indiana Department Environmental Management, Office of Air Quality, Permits Branch, 100 North Senate Avenue, MC 61-53 IGCN 1003, Indianapolis, Indiana 46204-2251 or by telephone at (317) 234-5328 or toll free at 1-800-451-6027 extension 4-5328.

(b) A copy of the findings is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/

(c) For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Permit Guide on the Internet at: http://www.in.gov/idem/5881.htm; and the Citizens' Guide to IDEM on the Internet at: http://www.in.gov/idem/6900.htm.

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

July 14, 2015

Ms. Natalie Grimmer
BP Products North America, Inc. – Whiting Business Unit
1701 121st Street
Whiting, IN 45394

Re: Public Notice
BP Products North America, Inc. –
Whiting Business Unit
Permit Level: Title V Significant Source Modification and Significant Permit Modification
Permit Number: 089-35708-00453 and
089-35729-00453

Dear Ms. Grimmer:

Enclosed is a copy of your draft Title V Significant Source Modification and Significant Permit Modification, Technical Support Document, emission calculations, and the Public Notice which will be printed in your local newspaper.

The Office of Air Quality (OAQ) has prepared two versions of the Public Notice Document. The abbreviated version will be published in the newspaper, and the more detailed version will be made available on the IDEM's website and provided to interested parties. Both versions are included for your reference. The OAQ has requested that The Post Tribune in Merrillville, Indiana and The Times in Munster, Indiana publish the abbreviated version of the public notice no later than July 15, 2015. You will not be responsible for collecting any comments, nor are you responsible for having the notice published in the newspaper.

OAQ has submitted the draft permit package to the Whiting Public Library, 1735 Oliver Street in Whiting, Indiana. As a reminder, you are obligated by 326 IAC 2-1.1-6(c) to place a copy of the complete permit application at this library no later than ten (10) days after submittal of the application or additional information to our department. We highly recommend that even if you have already placed these materials at the library, that you confirm with the library that these materials are available for review and request that the library keep the materials available for review during the entire permitting process.

Please review the enclosed documents carefully. This is your opportunity to comment on the draft permit and notify the OAQ of any corrections that are needed before the final decision. Questions or comments about the enclosed documents should be directed to Doug Logan, Indiana Department of Environmental Management, Office of Air Quality, 100 N. Senate Avenue, Indianapolis, Indiana, 46204 or call (800) 451-6027, and ask for extension 4-5328 or dial (317) 234-5328.

Sincerely,

Vivian Haun

Vivian Haun
Permits Branch
Office of Air Quality

Enclosures
PN Applicant Cover lette-2014. Dot4/10/14

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Governor

Thomas W. Easterly
Commissioner

ATTENTION: PUBLIC NOTICES, LEGAL ADVERTISING

July 10, 2015

The Post Tribune
1433 E. 83rd Avenue
Merrillville, IN 46410

Enclosed, please find one Indiana Department of Environmental Management Notice of Public Comment for BP Products North America, Inc. - Whiting Business Unit, Lake County, Indiana.

Since our agency must comply with requirements which call for a Notice of Public Comment, we request that you print this notice one time, no later than July 15, 2015.

Please send a notarized form, clippings showing the date of publication, and the billing to the Indiana Department of Environmental Management, Accounting, Room N1345, 100 North Senate Avenue, Indianapolis, Indiana, 46204.

To ensure proper payment, please reference account # 100174737.

We are required by the Auditor's Office to request that you place the Federal ID Number on all claims. If you have any conflicts, questions, or problems with the publishing of this notice or if you do not receive complete public notice information for this notice, please call Vivian Haun at 800-451-6027 and ask for extension 3-6867 or dial 317-233-6878.

Sincerely,

Vivian Haun

Vivian Haun
Permit Branch
Office of Air Quality

Permit Level: Title V Significant Source Modification and Significant Permit Modification
Permit Number: 089-35708-00453 and 089-35729-00453

Enclosure
PN Newspaper.dot 6/13/2013

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Michael R. Pence
Governor

Thomas W. Easterly
Commissioner

ATTENTION: PUBLIC NOTICES, LEGAL ADVERTISING

July 10, 2015

The Times
601 West 45th Avenue
Munster, IN 46321

Enclosed, please find one Indiana Department of Environmental Management Notice of Public Comment for BP Products North America, Inc., Lake County, Indiana.

Since our agency must comply with requirements which call for a Notice of Public Comment, we request that you print this notice one time, no later than July 15, 2015.

Please send a notarized form, clippings showing the date of publication, and the billing to the Indiana Department of Environmental Management, Accounting, Room N1345, 100 North Senate Avenue, Indianapolis, Indiana, 46204.

To ensure proper payment, please reference account # 100174737.

We are required by the Auditor's Office to request that you place the Federal ID Number on all claims. If you have any conflicts, questions, or problems with the publishing of this notice or if you do not receive complete public notice information for this notice, please call Vivian Haun at 800-451-6027 and ask for extension 3-6867 or dial 317-233-6878.

Sincerely,

Vivian Haun

Vivian Haun
Permit Branch
Office of Air Quality

Permit Level: Title V Significant Source Modification and Significant Permit Modification
Permit Number: 089-35708-00453 and 089-35729-00453

Enclosure
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Governor

Thomas W. Easterly
Commissioner

July 14, 2015

To: Whiting Public Library

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

Subject: **Important Information to Display Regarding a Public Notice for an Air Permit**

Applicant Name: BP Products North America, Inc. – Whiting Business Unit
Permit Number: 089-35708-00453 and 089-35729-00453

Enclosed is a copy of important information to make available to the public. This proposed project is regarding a source that may have the potential to significantly impact air quality. Librarians are encouraged to educate the public to make them aware of the availability of this information. The following information is enclosed for public reference at your library:

- Notice of a 30-day Period for Public Comment
- Request to publish the Notice of 30-day Period for Public Comment
- Draft Permit and Technical Support Document

You will not be responsible for collecting any comments from the citizens. Please refer all questions and request for the copies of any pertinent information to the person named below.

Members of your community could be very concerned in how these projects might affect them and their families. **Please make this information readily available until you receive a copy of the final package.**

If you have any questions concerning this public review process, please contact Joanne Smiddie-Brush, OAQ Permits Administration Section at 1-800-451-6027, extension 3-0185. Questions pertaining to the permit itself should be directed to the contact listed on the notice.

Enclosures
PN Library.dot 6/13/2013

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Thomas W. Easterly
Commissioner

Notice of Public Comment

July 14, 2015
BP Products North America, Inc. – Whiting Business Unit
089-35708-00453 and 089-35729-00453

Dear Concerned Citizen(s):

You have been identified as someone who could potentially be affected by this proposed air permit. The Indiana Department of Environmental Management, in our ongoing efforts to better communicate with concerned citizens, invites your comment on the draft permit.

Enclosed is a Notice of Public Comment, which has been placed in the Legal Advertising section of your local newspaper. The application and supporting documentation for this proposed permit have been placed at the library indicated in the Notice. These documents more fully describe the project, the applicable air pollution control requirements and how the applicant will comply with these requirements.

If you would like to comment on this draft permit, please contact the person named in the enclosed Public Notice. Thank you for your interest in the Indiana's Air Permitting Program.

Please Note: *If you feel you have received this Notice in error, or would like to be removed from the Air Permits mailing list, please contact Patricia Pear with the Air Permits Administration Section at 1-800-451-6027, ext. 3-6875 or via e-mail at PPEAR@IDEM.IN.GOV. If you have recently moved and this Notice has been forwarded to you, please notify us of your new address and if you wish to remain on the mailing list. Mail that is returned to IDEM by the Post Office with a forwarding address in a different county will be removed from our list unless otherwise requested.*

Enclosure
PN AAA Cover.dot 6/13/13

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Governor

Thomas W. Easterly
Commissioner

AFFECTED STATE NOTIFICATION OF PUBLIC COMMENT PERIOD
DRAFT INDIANA AIR PERMIT

July 14, 2015

A 30-day public comment period has been initiated for:

Permit Number: **089-35708-00453 and 089-35729-00453**
Applicant Name: **BP Products North America, Inc. – Whiting Business Unit**
Location: **Whiting, Lake County, Indiana**

The public notice, draft permit and technical support documents can be accessed via the **IDEM Air Permits Online** site at:
http://www.in.gov/ai/appfiles/idem-caats/

Questions or comments on this draft permit should be directed to the person identified in the public notice by telephone or in writing to:

Indiana Department of Environmental Management
Office of Air Quality, Permits Branch
100 North Senate Avenue
Indianapolis, IN 46204

Questions or comments regarding this email notification or access to this information from the EPA Internet site can be directed to Chris Hammack at chammack@idem.IN.gov or (317) 233-2414.

Affected States Notification.dot 3/13/2013

Mail Code 61-53

IDEM Staff	VHAUN 7/14/2015 089-35708 and 35729-00453 DRAFT BP Products North America Inc - Whiting Business Unit			AFFIX STAMP HERE IF USED AS CERTIFICATE OF MAILING
Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

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1		Natalie Grimmer BP Products North America Inc - Whiting Business U 1701 121st Street Whiting IN 46394 (Source CAATS)									
2		Jorge Lanza Refinery Manager BP Products North America Inc - Whiting Business U 2815 Indianapolis Boulevard Whiting IN 46394 *(RO CAATS)*									
3		East Chicago City Council 4525 Indianapolis Blvd East Chicago IN 46312 *(Local Official)*									
4		Lake County Health Department-Gary 1145 W. 5th Ave Gary IN 46402-1795 *(Health Department)*									
5		WJOB / WZVN Radio 6405 Olcott Ave Hammond IN 46320 *(Affected Party)*									
6		Hammond City Council and Mayors Office 5925 Calumet Avenue Hammond IN 46320 *(Local Official)*									
7		Shawn Sobocinski 5950 Old Porter Rd Aprt 306 Portage IN 46368-1558 *(Affected Party)*									
8		Mr. Tim Maloney Hoosier Environmental Council 3951 N. Meridian Suite 100 Indianapolis IN 46208 *(Affected Party)*									
9		Whiting City Council and Mayors Office 1143 119th St Whiting IN 46394 *(Local Official)*									
10		Mark Coleman 8 Turret Rd. Portage IN 46368-1072 *(Affected Party)*									
11		Mr. Chris Hernandez Pipefitters Association, Local Union 597 45 N Ogden Ave Chicago IL 60607 *(Affected Party)*									
12		Craig Hogarth 7901 West Morris Street Indianapolis IN 46231 *(Affected Party)*									
13		Whiting Public Library 1735 Oliver St Whiting IN 46394-1794 (Library)									
14		Lake County Commissioners 2293 N. Main St, Building A 3rd Floor Crown Point IN 46307 *(Local Official)*									
15		Anthony Copeland 2006 E. 140th Street East Chicago IN 46312 *(Affected Party)*									

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FACSIMILIE OF PS Form 3877

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Line	Article Number	Name, Address, Street and Post Office Address	Postage	Handing Charges	Act. Value (If Registered)	Insured Value	Due Send if COD	R.R. Fee	S.D. Fee	S.H. Fee	Rest. Del. Fee Remarks
1		Barbara G. Perez 506 Lilac Street East Chicago IN 46312 (Affected Party)									
2		Mr. Robert Garcia 3733 Parrish Avenue East Chicago IN 46312 *(Affected Party)*									
3		Joe Carroll Bloomberg News 111 S. Wacker Suite 4950 Chicago IL 60606 *(Affected Party)*									
4		Ms. Karen Kroczek 8212 Madison Ave Munster IN 46321-1627 *(Affected Party)*									
5		Rosemarie Cazeau Illinois Attorney General Office 69 W Washington St 18th floor Chicago IL 60602 *(Affected Party)*									
6		Environmental Law and Policy Center 35 E Wacker Dr #1600 Chicago IL 60601 *(Affected Party)*									
7		Joseph Hero 11723 S Oakridge Drive St. John IN 46373 *(Affected Party)*									
8		Bessie Dent Calumet Project 200 Russell St., Ste. 304 Hammond IN 46320 *(Affected Party)*									
9		Mr. Thomas Frank 1616 E 142nd Street East Chicago IN 46312 *(Affected Party)*									
10		Tom Anderson Save the Dunes 444 Barker Rd Michigan City IN 46360 *(Affected Party)*									
11		Mr. Steve Kozel The Calumet Project 200 Russell St., Ste. 304 Hammond IN 46320 *(Affected Party)*									
12		Sierra Club, Inc. - Hoosier Chapter 1100 W. 42nd Street, Suite 140 Indianapolis IN 46208 *(Affected Party)*									
13		Sparsh Khandeshi Environmental Integrity Project 1000 Vermont Ave NW, Suite 1100 Washington DC 20005 (Affected Party)									
14		Gary City Council 401 Broadway # 209 Gary IN 46402 *(Local Official)*									
15		Mr. Larry Davis 268 South, 600 West Hebron IN 46341 *(Affected Party)*									

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Name and address of Sender	▶	Indiana Department of Environmental Management Office of Air Quality – Permits Branch 100 N. Senate Indianapolis, IN 46204	Type of Mail: **CERTIFICATE OF MAILING ONLY**	

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1		Kim Chrislip Genscape 1710 29th Street, Ste. 2044 Boulder CO 80301 (Affected Party)									
2		Bryan Bullock Counsel for Calumet Project 7863 Broadway, Suite 222 Merrillville IN 46410 *(Affected Party)*									
3		Tom Soulis 3646 Ridge Road Highland IN 46322 *(Affected Party)*									
4		Susan Eleuterio 3646 Ridge Road Highland IN 46322 *(Affected Party)*									
5		Jennifer Peterson Environmental Integrety Project 1920 L. Street NW, Suite 800 Washington DC 20036 *(Affected Party)*									
6		Kay Nelson 6100 Southport Road Portage IN 46368 *(Affected Party)*									
7		Ryan Dave 939 Cornwallis Munster IN 46321 *(Affected Party)*									
8		Edwin Bybel 2440 Scharge Avenue Whiting IN 46394 *(Affected Party)*									
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Total number of pieces Listed by Sender	Total number of Pieces Received at Post Office	Postmaster, Per (Name of Receiving employee)	The full declaration of value is required on all domestic and international registered mail. The maximum indemnity payable for the reconstruction of nonnegotiable documents under Express Mail document reconstructing insurance is $50,000 per piece subject to a limit of $50, 000 per occurrence. The maximum indemnity payable on Express mil merchandise insurance is $500. The maximum indemnity payable is $25,000 for registered mail, sent with optional postal insurance. See ***Domestic Mail Manual*** **R900, S913**, and **S921** for limitations of coverage on inured and COD mail. See ***International Mail Manual*** for limitations o coverage on international mail. Special handling charges apply only to Standard Mail (A) and Standard Mail (B) parcels.
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