INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
We Protect Hoosiers and Our Environment.
100 N. Senate Avenue • Indianapolis, IN 46204
(800) 451-6027 • (317) 232-8603 • www.idem.IN.gov

Eric J. Holcomb
Governor

Brian C. Rockensuess
Commissioner

NOTICE OF 30-DAY PERIOD FOR PUBLIC COMMENT

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

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

Significant Permit Modification No.: 089-45450-00453

The Indiana Department of Environmental Management (IDEM) has received an application from BP Products North America, Inc. - Whiting Business Unit, located at 2815 Indianapolis Boulevard, Whiting, Indiana 46394, for a significant modification of its Part 70 Operating Permit issued on January 1, 2015. 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. IDEM issued SPM No. 089-43173-00453, on June 2, 2021. On March 4, 2002, U.S. EPA issued an Order Granting in Part and Denying in Part the Petition for Objection to Permit (Petition No. V-2021-9). As a result, BP Products North America, Inc. - Whiting Business Unit has applied to address the two claims granted by the U.S. EPA.

This draft 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 have been sent to:

Whiting Public Library
1735 Oliver Street
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/.

A copy of the application and preliminary findings is also available via IDEM's Virtual File Cabinet (VFC). To access VFC, please go to: https://www.in.gov/idem/ and enter VFC in the search box. You will then have the option to search for permit documents using a variety of criteria.

How can you participate in this process?
This notice is posted on IDEM's website (https://www.in.gov/idem/public-notices/). The date that this notice is posted on IDEM's website 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 IDEM decides to conduct a public hearing and/or public meeting, IDEM will post a separate announcement of the date, time, and location of that public hearing and/or public meeting on IDEM's website (https://www.in.gov/idem/public-notices/). 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 SPM 089-45450-00453 in all correspondence.

Comments should be sent to:

Aasim Noveer
IDEM, Office of Air Quality
100 North Senate Avenue
MC 61-53 IGCN 1003
Indianapolis, Indiana 46204-2251
(800) 451-6027, ask for Aasim Noveer or (317) 234-1243
Or dial directly: (317) 234-1243
Fax: (317) 232-6749 attn: Aasim Noveer
E-mail: ANoveer@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 Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

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 and will also be sent to the local library indicated above, 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 Aasim Noveer of my staff at the above address.

Brian Williams

Brian Williams, Section Chief
Permits Branch
Office of Air Quality

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Mr. Caleb Gingerich
BP Products North America, Inc. - Whiting Business Unit
2815 Indianapolis Boulevard
Whiting, Indiana 46394

Re: 089-45450-00453
Significant Permit Modification

Dear Mr. Gingerich:

BP Products North America, Inc. - Whiting Business Unit was issued Part 70 Operating Permit Renewal No. T089-30396-00453 on January 1, 2015, for a stationary refinery and marketing terminal located at 2815 Indianapolis Boulevard, Whiting, Indiana 46394. An application requesting changes to this permit was received on May 23, 2022. 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. The permit references the below listed attachments. 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
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.vii:	40 CFR 60, Subpart UU, Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture
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

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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.xiii:	40 CFR 60, Subpart NNN, Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations
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 C.xvi:	40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
Attachment C.xvii:	40 CFR 60, Subpart JJJJ, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
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.ii:	40 CFR 63, Subpart Y, National Emission Standards for Marine Tank Vessel Loading Operations
Attachment E.iii:	40 CFR 63, Subpart CC, National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries
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
Attachment F.i:	Appendix FLR-1 to the Consent Decree entered in Civil No. 2:12-CV-00207
Attachment F.ii:	Appendix FLR-2 to the Consent Decree entered in Civil No. 2:12-CV-00207
Attachment F.iii:	Appendix FLR-3 to the Consent Decree entered in Civil No. 2:12-CV-00207
Attachment F.v:	Appendix FLR-5 to the Consent Decree entered in Civil No. 2:12-CV-00207
Attachment F.vi:	Appendix FLR-6 to the Consent Decree entered in Civil No. 2:12-CV-00207
Attachment F.vii:	Appendix FLR-7 to the Consent Decree entered in Civil No. 2:12-CV-00207
Attachment F.x:	Appendix FLR-10 to the Consent Decree entered in Civil No. 2:12-CV-00207
Attachment F.xi:	Appendix FLR-11 to the Consent Decree entered in Civil No. 2:12-CV-00207
Attachment F.xiii:	Appendix FLR-13 to the Consent Decree entered in Civil No. 2:12-CV-00207
Attachment F.xiv:	Appendix FLR-14 to the Consent Decree entered in Civil No. 2:12-CV-00207
Attachment F.xv:	Appendix FLR-15 to the Consent Decree entered in Civil No. 2:12-CV-00207

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

Previously issued approvals for this source are also available via IDEM's Virtual File Cabinet (VFC). To access VFC, please go to: https://www.in.gov/idem/ and enter VFC in the search box. You will then have the option to search for permit documents using a variety of criteria.

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.

A copy of the permit is available on the Internet at: http://www.in.gov/ai/appfiles/idem-caats/. A copy of the application and permit is also available via IDEM's Virtual File Cabinet (VFC). To access VFC, please go to: https://www.in.gov/idem/ and enter VFC in the search box. You will then have the option to search for permit documents using a variety of criteria. For additional information about air permits and how the public and interested parties can participate, refer to the IDEM Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

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

If you have any questions regarding this matter, please contact Aasim Noveer, 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) 234-1243 or (800) 451-6027, and ask for Aasim Noveer or (317) 234-1243.

Sincerely,

Brian Williams, 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 Boulevard
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 Master Agency Interest ID.: 11589	
Issued by: Original Signed by: Jenny Acker, Section Chief Permits Branch, Office of Air Quality	Issuance Date: January 1, 2015 Expiration Date: January 1, 2020

Administrative Amendment No. 089-35450-00453, issued on February 19, 2015
Significant Permit Modification 089-35729-00453, issued on September 16, 2015
Significant Permit Modification 089-36656-00453, issued on June 14, 2016
Administrative Amendment No. 089-36920-00453, issued on June 15, 2016
Significant Permit Modification No.: 089-37390-00453, issued on December 28, 2016
Administrative Amendment No.: 089-38381-00453, issued on May 15, 2017
Significant Permit Modification No.: 089-38641-00453, issued on October 4, 2017
Significant Permit Modification No.: 089-38868-00453, issued on January 29, 2018
Minor Permit Modification No.: 089-39973-00453, issued on August 27, 2018
Administrative Amendment No.: 089-40242-00453, issued on September 12, 2018
Significant Permit Modification No.: 089-40517-00453, issued on September 20, 2019
Minor Permit Modification No.: 089-42328-00453, issued on September 9, 2020
Significant Permit Modification No.: 089-43173-00453, issued on June 2 2021
Significant Permit Modification No.: 089-42998-00453, issued on August 5, 2021
Significant Permit Modification No.: 089-44305-00453, issued on December 9, 2021

Significant Permit Modification No.: 089-45450-00453	
Issued by: Brian Williams, 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, the Whiting Business Unit (Plant ID 089-00453), consists of a single plant:

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

The stationary source formerly included one other plant:

(2) The Marketing Terminal (previously designated 089-00004), located at 2530 Indianapolis Boulevard, Whiting, Indiana 46394. The Marketing Terminal was permanently decommissioned and removed from the source in Minor Source Modification No. 089-42309-00453.

The source determination also formerly considered one other plant:

(3) INEOS USA LLC (designated as 089-00076), 2357 Standard Avenue, Whiting, IN 46394. Significant Source Modification No. 089-22011-00076, issued on March 20, 2006, withdrew an earlier determination that the source then owned by INEOS USA, LLC was part of the BP Products North America - Whiting Business Unit (Plant ID 089-00453) source. The 2006 determination was based on a sale of shares that eliminated any common ownership of the two sources._INEOS USA LLC ceased operation and its Part 70 Operating Permit No. 089-31963-00076 was revoked in Revocation No. 089-35599-00076, issued on March 25, 2015.

(b) The BP Whiting Refinery (BP) needs high pressure steam and high pressure hydrogen for its Whiting Refinery Modernization Project (WRMP). Linde Inc. owns and operates a plant near the BP facility (2551 Dickey Rd., East Chicago, IN 46312) that produces low pressure hydrogen, carbon dioxide and low pressure steam (Plant A, Plant ID 089-00435, Linde's unit identification SMR1, SMR2, SMR3, and SMR4). Linde'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, Linde constructed a new plant (Plant B, identified as HU-1 and HU-2 in the BP permit) near Plant A and sharing the same physical address. IDEM, OAQ examined whether Linde's Plant B is part of the same major source as Linde's Plant A, and whether one or both of the Linde 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 Linde Plants

The first analysis will be of the relationship between the two Linde plants. The Linde plants are owned by Linde. 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 Linde 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 Linde 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. Linde's Plant B is located approximately 75 yards from Linde's Plant A. The plants are separated by property owned by Mittal Steel. A Mittal Steel bridge runs between the two Linde 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.

Linde 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. Linde has stated that it will not operate Plant B if the WRMP were to cease operation. Linde 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 Linde 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 plants. Linde uses the same plant manager for other Linde sources that are in the same general area, even when the sources are miles apart. Linde employs additional regional employees with offices at Plant B that have responsibilities at Plant A, Plant B and two other regional Linde plants in Michigan. Linde hired additional employees to operate Plant B. All Linde 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 Linde plants in the region and elsewhere. Linde 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 has its own control room, supply room, parts room and functions as a stand-alone plant. The production process is not split in any way between the two Linde plants. The raw materials Plant B uses to produce hydrogen and high pressure steam, natural gas, refinery gas and water, come directly from BP.

The two Linde plants do not operate as a single source. Though the plants 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 Linde plants are not part of the same major source.

The Linde Plants and the BP Whiting Refinery

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

The Linde 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 dedicates at least 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 supplies all of the natural gas, refinery gas and water used by Plant B. BP has 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 flow through lines from BP to Plant B. Plant B uses that fuel and raw material to create high pressure steam and hydrogen which is 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* (11A)	250	120-01	Ultra Low NO_X Burners
H-2 (11A)	45	120-02	None
H-3 (11A)	55	120-03	None
H-200* (11C)	249.5	120-05	Ultra Low NO_X Burners
H-300 (11C)	180	120-06	Ultra-Low NOx Burners

* 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.

A Brine Conditioning System (BCS), added as part of the WEP, including the following units:

(9) T-400 Brine Stripper Tower, approved in 2017 for construction.

(10) D-400 Stripper Overhead Receiver, approved in 2017 for construction.

(11) D-401 Liquid Ring Separator, approved in 2017 for construction.

(12) D-402 Second Stage Liquid Ring Separator Drum, approved in 2018 for construction.

(13) D-403 Oil Skimming Drum, approved in 2018 for construction.

(14) 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.

(15) Leaks from process equipment, including pumps, compressors (K-400A, K-400B and K-400C), pressure relief devices, sampling connection systems, open-ended lines and valves, and heat exchange and instrumentation systems, approved in 2017 for construction, and compressors K-401A and K-401B, approved for construction in 2018.

(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).The No. 11B Coker and existing Coke Handling System, heaters H-101, H-102, H-103, and H-104 were permanently shut down as of May 10, 2014.

(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. As part of the WEP, there is a replacement of tubes and outlet piping on the existing heaters with an upgraded metallurgy to reduce fouling. There will also be enhancements made to the Coke Handling System (installation of new rail track and crane automation improvements). Also, there are new piping connections (valves and flanges). 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 feed at a vapor pressure less than 0.5 psia. Tank TK-6254 is equipped with a fixed roof, nitrogen blanketed, and vented to a caustic scrubber and carbon canister control system in series (Option 1 Controls) or vented to a vapor recovery system (Option 2 Controls). The vapor recovery system routes the vapors from TK-6254 to the flare gas recovery system (FGRS) at the South Flare (FGRS1).

(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).

(H) Storage vessels containing coker feed with a maximum true vapor pressure, as defined at 326 IAC 8-9-6(i)(4)(A), less than 0.5 psia, as follows:

(1) One (1) fixed roof storage vessel, identified as TK-6126, constructed in 1999, approved in 2021 for modification, with a

maximum storage capacity of 3,108,000 gallons (11,764 m^3), venting to a vapor recovery system (Option 2 Controls).

(2) One (1) fixed roof storage vessel, identified as TK-6127, constructed in 2000, approved in 2021 for modification, with a maximum storage capacity of 3,108,000 gallons (11,764 m^3), venting to a vapor recovery system (Option 2 Controls).

(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. As part of the WEP, there will be new control valves, instrumentation upgrades (valves, flanges) and new piping connections (valves, flanges). 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
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.
**Heaters H-1AN, H-1AS, H-1B, H-2, H-1CN, H-1CX were permanently shut down as of November 30, 2012.

(2) RESERVED

(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) RESERVED

(3) RESERVED

(4) RESERVED

(5) RESERVED

(6) RESERVED

(7) RESERVED

(8) RESERVED

(9) RESERVED

(10) RESERVED

(11) RESERVED

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

(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) The sealed sulfur collection 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).

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.

(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. As part of WEP, there will be rerouting of naphtha streams (valves and flanges), removal of hydraulic constraints (pump modifications), and new piping connections (valves and flanges).

(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.

The following sources have been added as part of the WEP:

(C) RESERVED

(D) As part of WEP, there will be rerouting of naphtha streams (valves and flanges), removal of hydraulic constraints (pump modifications), replacement of trays in distillation towers, upgrades to heat exchangers, and new piping connections (valves and flanges)

(2) Vapor Recovery Unit VRU 400 for the Coker 2, permitted in 2008, to be installed as part of the WRMP project, approved in 2016 for modification. 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. As part of the WEP, there are tray modifications in distillation towers and new piping connections

(valves and flanges). 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.

(6) As part of the WEP, there are removal of hydraulic constraints (pump modifications), installation of a cooler, and new piping connections (valves, flanges).

(7) One (1) spent acid storage tank, identified as Tank 6, constructed in 1993, with a maximum storage capacity of 101,650 gallons, equipped with a fixed roof and controlled by carbon canisters.

(8) Two (2) spent acid degassing drums, identified as D-20 and D-21, with emissions vented to the alky Flare and associated flare gas recovery system FGRS3 (included in Section D.35).

(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. As part of the WEP, there are modifications to trays and new nozzles for the distillation towers, and new piping connections (valves and flanges). 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.

As part of the WEP, there are modifications to the C-250 feed drum, removal of hydraulic constraints (pump modifications), installation of a filter coalescer, and the installation of new piping connections (valves and flanges).

(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. As part of the WEP, there are removal of hydraulic constraints (pump modification) and new piping connections (valves and flanges). 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

Heater Identification	Maximum Heat Input Capacity (mmBTU/hr)	Stack Exhausted To	Emission Controls
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.

(7) As part of the WEP, there are new fugitive components (valves, flanges and pumps).

(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 ther 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°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°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

The No. 1 SPS Boilers 5, 6, and 7 were shut down as of April 1, 2010 as specified in Consent Decree 2:96 CV 095RL.

(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) Five (5) Boilers, each approved in 2008 for modification as a contemporary project to the WRMP project, each equipped with conventional burners, a Selective Catalytic Reduction (SCR) system, and a direct-fired Duct Burner. Each direct-fired Duct Burner rated at 41 mmBTU/hr, equipped with low-Nox burners, and controlled by the Selective Catalytic Reduction (SCR) system. Each stack equipped with continuous emissions monitors (CEMS) for NOx and CO:

Boiler and Duct Burner Identification	Maximum Heat Input Capacity (mmBTU/hr)	Installation Date	Modification Date	Emissions Control	Stack Exhausted To
#31 Boiler	575	1948	2010	SCR	503-01 (NOx & CO CEMS)
#31 Duct Burner	41	2010	--		
#32 Boiler	575	1948	2010	SCR	503-02 (NOx & CO CEMS)
#32 Duct Burner	41	2010	--		
#33 Boiler	575	1951	2010	SCR	503-03 (NOx & CO CEMS)
#33 Duct Burner	41	2010	--		
#34 Boiler	575	1951	2010	SCR	503-04 (NOx & CO CEMS)
# 34 Duct Burner	41	2010	--		
#36 Boiler	575	1953	2011	SCR	503-05 (NOx & CO CEMS)
#36 Duct Burner	41	2011	--		

(2) 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 Flotation (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 Flotation (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 Flotation (DNF) System, installed as a part of the Lakefront Upgrades Project; and Dissolved Air Flotation (DAF) Secondary Boxes, which vent to a biofilter and carbon canisters; Tank 562 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 Flotation (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) RESERVED

(2) RESERVED

(3) External floating roof storage tanks storing petroleum hydrocarbon with vapor pressure less than 11.1 psia, comprising the following tanks:

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3529	1948	858,000
3901	1956	1,906,000

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
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-three (63) internal floating roof storage tanks, storing petroleum hydrocarbon with true 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	1924/2018[1]	3,380,000
3484	1996/2021[2]	3,382,264 3,380,000 after replacement
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	4,061,000

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
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	3,380,000
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

Tank No.	Year Built or Modified	Maximum Capacity (gallons)
3706	1944	3,382,264
3707	1944/2000	3,380,000
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

Notes:
1. *These units are to be replaced with like units and were approved in 2018 for construction. The exact construction years will be added after construction is complete.*
2. *TK-3484 was approved in 2021 for reconstruction. The actual date that reconstruction commences will be added as a change in the descriptive information upon completion of the reconstruction.*

(5) Miscellaneous Storage tanks including the following:

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity (gallons)	True Vapor Pressure of Liquid (psia)
D-424	4ULTRAFORMER	Methanol Tank	--[1]	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 or biodiesel	1992/2021[2]	3,876,768	<0.5
TK-3496	SO. TK FLD.	Distillate	1992	3,876,768	<0.5
TK-3498R	SO. TK FLD.	Amoco Premier Diesel [Future Lsfo]	Approved in 2016 for Construction	4,229,840	<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

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity (gallons)	True Vapor Pressure of Liquid (psia)
TK-3505	SO. ANNEX	Heater Oil	1949	4,254,768	<0.5
TK-3509	SO. TK FLD.	Petroleum Distillate	1948/2018[3]	3,380,000	<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
TK-3567	--	--	--	17,000	<0.5
TK-3569	MARINE DOCK	DCO	1981	5,527,375	<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-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.	Petroleum Distillate	1945/2018[3]	3,356, 000	<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-3717R	IND. TK FLD.	Gas Oil	Approved in 2016 for Construction	4,229,840	<0.5
TK-3718	IND. TK FLD.	Gas Oil	1996	3,871,379	<0.5
TK-3719	IND. TK FLD.	Gas Oil	2015	3,357,627	<0.5
TK-3720	IND. TK FLD.	Petroleum Distillate	1946/2018[3]	3,356,000	<0.5
TK-3721	IND. TK FLD.	Gas Oil	1946	3,357,600	<0.5
TK-3721R	IND. TK FLD.	Gas Oil	Approved in 2016 for Construction	4,229,840	<0.5
TK-3722	IND. TK FLD.	Gas Oil	1952	4,227,300	<0.5
TK-3723	IND. TK FLD.	Gas Oil	2016	3,386,880	<0.5
TK-3733	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,383,520	<0.5
TK-3734	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,383,520	>0.5 and <0.75
TK-3735	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,411,072	<0.5
TK-3867	SO. TK FLD.	Stadis 450	1967	17,640	<0.5
TK-3868	SO. TK FLD.	Amogard	1953	17,640	>0.5 and <0.75
TK-3869	SO. TK FLD.	Pour Depressant	1956	23,436	<0.5
TK-3872	CRUDE STA	Used Motor Oil	1985	15,120	<0.5
TK3876	South TF	Cetane Improver	1993	14,381	<0.5
TK-3906	J&L TK FLD.	Lsfo	1956	3,381,840	>0.5 and <0.75
TK-3908	J&L TK FLD.	Amoco Premier Diesel	1956	3,381,840	<0.5
TK-3910	J&L TK FLD.	Furnace Oil [Hs]	1956	3,381,840	<0.5

Tank ID	Location	Description	Tank Construction Dates	Tank Capacity (gallons)	True Vapor Pressure of Liquid (psia)
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.	Petroleum Distillate	2020[4]	4,231,000	<0.5
TK-3506	SO. ANNEX	Petroleum Distillate	2020[4]	4,231,000	,0.5
TK-3710	IND. TK FLD.	Petroleum Distillate	2020[4]	3,385,000	<0.5
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	--	--	--
TK-3490	SO. TK FLD	Petroleum Distillate	1925	3,371,000	<0.5
3495		--	1992	3,876,768	<0.5

Notes:
1. *"--" - no data provided.*
2. *Optional biodiesel service of this tank was approved in MSM No.089-44288-00453. The actual date that modification commences will be added as a change in the descriptive information upon completion of the modification.*
3. *These units are to be replaced with like units and were approved in 2018 for construction. The exact construction years will be added after construction is complete.*
4. *These units were approved in 2020 for construction. The entry will be revised to the actual construction date after construction commences.*

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

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

(11) Fugitive components constructed as part of the construction of TK-3498R, TK-3717R, and TK-3721R, permitted in 2016.

(12) As part of the WEP, there are improvements to the Crude Tank Field, including reconfigurations of the crude field piping (valves and flanges), and new piping connections (valves and flanges).

(13) As part of WEP, there are the installation of piping connections (valves and flanges), removal of hydraulic constraints (pump modifications), heat exchanger upgrades, and new chillers.

(14) Fugitive components associated with TK-3497, TK-3506, and TK-3710, approved in 2020 for construction.

(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:

<table>
<tr><th>Facility I.D.</th><th>Installation Date</th><th>S/V I.D.</th><th>Normal Venting</th><th>Controls</th></tr>
<tr><td>J-137</td><td>1992</td><td>999-02</td><td>Vented Separately</td><td>Uncontrolled</td></tr>
<tr><td>J-138</td><td>1991
Extension 1994</td><td>999-03</td><td rowspan="2">J-138 and J-140 are vented with D-138 (vapor/liquid separation tank)</td><td rowspan="2">0.685 mmBTU per hour Thermal Oxidizer ITF</td></tr>
<tr><td>J-140</td><td>1981</td><td>999-05</td></tr>
<tr><td>J-141</td><td>1988
Extension 1993</td><td>999-06</td><td>Vented Separately</td><td>Uncontrolled</td></tr>
<tr><td>J-156</td><td>1968-1970</td><td>999-07</td><td>Vented with J-157</td><td>Uncontrolled</td></tr>
<tr><td>J-157</td><td>1968-1970</td><td>999-08</td><td>Vented with J-156</td><td>Uncontrolled</td></tr>
<tr><td>J-162</td><td>1996</td><td>999-14</td><td>Vented Separately</td><td>Uncontrolled</td></tr>
<tr><td>J-163</td><td>1996</td><td>999-15</td><td>Vented Separately</td><td>Uncontrolled</td></tr>
</table>

(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).

The Marketing Terminal was permanently decommissioned pursuant to Minor Permit Modification No. 089-42328-00453.

(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 one (1) asphalt storage tank used to store volatile organic liquids that has a vapor pressure less than 0.75 psi:

Identification	Storage Capacity (gallons)	Year Constructed
TK-3613	8,866,200	1992

(3) The following four (4) 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
TK-3571	5,040,000	1971
TK-3572	5,040,000	1971
TK-3609*	9,652,608	1973 Modified in 2017
TK-3611	8,513,400	1973

* TK-3609 equipped with nitrogen sparging and a biofilter.

Under 40 CFR 63, Subpart CC, TK-3609 is considered as a Group 2 storage vessel that is part of the existing affected source.

Under 40 CFR 60, Subpart UU, TK-3609 is considered an affected facility.

(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	TK-3616
TK-3617	Trim Gas Oil	2007*	2,268,000	16,800,000	TK-3617
*Construction completed in 2007					

Under 40 CFR 60, Subpart UU, storage tanks TK-3614 and TK-3615 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)	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

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
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, K-103B, and K-103C; 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.

(1) As part of the WEP, there are new piping connections (valves and flanges).

(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 Linde 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-9210 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.

(pp) The Naphtha Hydrotreater (NHT), identified as Unit ID 810, approved in 2016 for construction, removes sulfur from petroleum naphthas. Petroleum naphthas are heated and sent through a Selective Hydrotreating Unit (SHU) reactor, D-701, to prevent fouling downstream and to treat diolefins. The SHU reactor effluent is routed to a Hydrodesulfurization (HDS) reactor, D-702, to further reduce sulfur content. The HDS reactor effluent is cooled, and the HDS reactor's vapor stream is sent to the amine absorber tower, C-701, to remove H2S from the unreacted hydrogen prior to being recycled within the NHT unit and purged as needed to the hydrogen header system. The HDS reactor's liquid stream is sent to the stabilizer distillation column, C-702, to separate lighter components entrained in the desulfurized naphtha. Additional sulfur is removed from the stabilizer's off-gas at the stabilizer off-gas amine contactor tower, C-703, prior to being recycled to the fuel gas system. Desulfurized naphtha is pumped to the tank fields for gasoline blending. Sulfur containing sour water and amine streams are sent to the SRP. The NHT includes the following sources of emissions:

(1) One (1) hydrodesulfurization (HDS) reactor heater, identified as F-701, with a maximum rated capacity of 104.2 mmBTU/hr, with emissions uncontrolled and exhausting to stack 810-01. The HDS reactor heater is equipped with low-NO_X burners, a NOx CEMS, has natural gas-fired pilot lights, and burns refinery fuel gas. The HDS reactor heater provides heat for the HDS reactor feed and effluent streams.

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

(3) The NHT Unit is connected to the GOHT Flare and associated flare gas recovery system FGRS 2 (included in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns.

(4) As part of the WEP, there are new piping connections (valves and flanges).

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)(J)(xiii)];

(b) Asbestos abatement projects regulated by 326 IAC 14-10 [326 IAC 2-7-1(21)(J)(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)(J)(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)(J)(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)(J)(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)(J)(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 equal to or less than five hundred thousand (500,000) British thermal units per hour except where total capacity of equipment operated by one (1) stationary source as defined in 326 IAC 2-7-1(39) exceeds two million (2,000,000) British thermal units per hour. [326 IAC 2-7-1(21)(J)(i)(BB)] [40 CFR 60, Subpart IIII] [40 CFR 60, Subpart JJJJ] [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 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.

A stage II vapor recovery system was decommissioned in accordance with 326 IAC 8-4-6(d).

(j) The following VOC and HAP storage containers [326 IAC 2-7-1(21)(J)(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)(J)(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)(J)(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)(J)(vi)(DD)].

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

(o) Ground water oil recovery wells [326 IAC 2-7-1(21)(J)(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)(J)(ix)(AA)].

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

(u) Repair activities including the following [326 IAC 2-7-1(21)(J)(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)(J)(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)(J)(xix)].

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

(y) Activities associated with emergencies, as follows:

  (1) On-site fire training approved by the department. [326 IAC 2-7-1(21)(J)(xxii)(AA)]

  (2) Emergency generators as follows: [326 IAC 2-7-1(21)(J)(xxii)(BB)]

    (A) Gasoline generators not exceeding one hundred ten (110) horsepower; [326 IAC 2-7-1(21)(J)(xxii)(BB)(aa)] [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

    (B) Diesel Generators not exceeding one thousand six hundred (1,600) horsepower. [326 IAC 2-7-1(21)(J)(xxii)(BB)(bb)] [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ]

(C) Natural gas turbines or reciprocating engines not exceeding sixteen thousand (16,000) horsepower. [326 IAC 2-7-1(21)(J)(xxii)(BB)(cc)] [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

(3) Stationary fire pump engines. [326 IAC 2-7-1(21)(J)(xxii)(CC)] [40 CFR 60, Subpart IIII] [40 CFR 60, Subpart JJJJ] [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)(J)(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)(J)(xviii)]:

(1) Sodium sulfate.

(2) Ammonia.

(3) Sulfur trioxide.

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

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

(ee) Diesel-fired engines, as follows:

(1) One (1) emergency fire pump engine, identified as Firepump Engine 1 (PU-300B), a 2010 model year engine permitted and installed in 2012, with a maximum capacity of 359 HP. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ]

(2) Two (2) non-emergency pump engines, identified as Pump Engine 2 (P-31) and Pump Engine 3 (P-32), 2010 model year engines permitted and installed in 2012, each with a maximum capacity of 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]

(ii) Two (2) propane-fired emergency generator engines, identified as Radio Tower Emergency Engine 1 and Radio Tower Emergency Engine 2, permitted in 2019, each with a maximum capacity of 230 HP. [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

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.

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 317-233-8590 (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(c).

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

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(11)] [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 Quality Improvement Plan (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)(c) 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)(c) 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(33) (“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.

Consent Decree Requirements

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.

(b) As specified by Appendix D, Emission Reductions from Flares and Control of Flaring Events, to the Consent Decree entered in Civil No. 2:12-CV-00207, the following definitions shall apply to the requirements for Covered Flares, as defined at (22) below, in Condition D.35.8:

(1) "Acid Gas" shall mean any gas that contains hydrogen sulfide and is generated at a refinery by the regeneration of an amine scrubber solution, but does not include Tail Gas.

(2) "Acid Gas Flaring" or "AG Flaring" shall mean the combustion of Acid Gas and/or Sour Water Stripper Gas in one or more AG Flaring Device(s).

(3) "Acid Gas Flare" or "AG Flare" shall mean a Flare that is used for the purpose of combusting Acid Gas and/or Sour Water Stripper Gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid. BPP currently operates a Flare it has designated as the "SRU Flare" as an AG Flare at the Refinery. To the extent that, during the duration of this Consent Decree, BPP commences operation of an AG Flare other than or in addition to the SRU Flare for the purpose of combusting Acid Gas and/or Sour Water Stripper Gas, that or those AG Flare(s) shall be covered under paragraph D.35.8.H or Sections H and I of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207.

(4) "Acid Gas Flaring Incident" or "AG Flaring Incident" shall mean the continuous or intermittent combustion of Acid Gas and/or Sour Water Stripper Gas in an AG Flare that results in the emission of SO_2 equal to, or in excess of, 500 pounds in any 24-hour period; provided, however, that if 500 pounds or more of sulfur dioxide has been emitted in a 24-hour period and Acid Gas Flaring continues into subsequent, contiguous, non-overlapping 24-hour period(s), each period of which results in emissions equal to, or in excess of, 500 pounds of SO_2, then only one AG Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of flaring within the AG Flaring Incident. If, at any time during the term of this Consent Decree, the Whiting Refinery has more than one AG Flare, and if AG Flaring occurs within a 24 hour period at more than one such AG Flare, the quantity of sulfur dioxide attributable to AG Flaring emitted from each such AG Flare shall be added together for purposes of determining whether there is one AG Flaring Incident, unless the root causes of the flaring at the various AG Flares are not related to each other.

(5) "Air-Assisted Flare" shall mean a Flare that utilizes forced air piped to a Flare tip to assist in combustion; a Flare that utilizes a Minimum Steam Reduction System is a Steam-Assisted, not an Air-Assisted, Flare.

(6) "Air Mass Flow Rate at Stoichiometric Conditions based on Vent Gas Mass Flow Rate" or "$\dot{m}_{air\text{-}stoich\text{-}vg}$" shall mean the mass of air needed to reach a stoichiometric ratio based on the actual Vent Gas Mass Flow Rate. The $\dot{m}_{air\text{-}stoich\text{-}vg}$ is

represented by and shall be calculated according to Equation 4 in Appendix FLR-15 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.xv to the operating permit.

(7) "Assist Air" or "Air_{asst}" shall mean all air that intentionally is introduced into an Air-Assisted Flare to assist in combustion. Assist Air does not include ambient air, air introduced through in a Minimum Steam Reduction System, or air entrained in Vent Gas.

(8) "Assist Air Mass Flow Rate" or "$\dot{m}_{air\text{-}asst}$" shall mean the mass flow rate of all Assist Air supplied to an Air-Assisted Flare, in pounds per hour (lb/hr), on a 5-minute block average basis. The $\dot{m}_{air\text{-}asst}$ is represented by and shall be calculated according to Equation 5 in Appendix FLR-15 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.xv to the operating permit.

(9) "Automatic Control System" shall mean a system that utilizes programming logic to automate the operation of the instrumentation and systems required in paragraphs D.35.8.B.7 – D.35.8.B.13, D.35.8.G.42.a and D.35.8.G.42.b so as to produce the operational results required in paragraphs D.35.8.F.30, D.35.8.F.33 – D.35.8.F.35, D.35.8.F.37, and D.35.8.G.45.

(10) "Baseload Waste Gas Flow Rate" shall mean, for a particular Covered Flare, the daily average flow rate, in scfd, to the Flare, excluding all flows during periods of startup, shutdown, and Malfunction. The flow rate data period that shall be used to determine Baseload Waste Gas Flow Rate for the Covered Flares is set forth in Subparagraph 18.b.ii of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207. The Baseload Waste Gas Flow Rate shall be identified in the Initial Waste Gas Minimization Plan due under Subparagraph 18.b.ii and may be updated in subsequent Waste Gas Minimization Plans due under Paragraphs 19 and 20 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207.

(11) "BTU/scf" shall mean British Thermal Unit per standard cubic feet.

(12) "Calendar Quarter" shall mean a three-month period ending on March 31, June 30, September 30, or December 31.

(13) "Center Steam" or "S_{cen}" shall mean steam piped into the center of a Flare stack or center of the lower part of the Flare tip where it mixes directly with Vent Gas without entraining air. Diagrams illustrating the meaning and location of Center, Lower, and Upper Steam are set forth in Appendix FLR-1 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.i to the operating permit.

(14) "Center Steam Volumetric Flow Rate" or "$Q_{s\text{-}cen}$" shall mean the volumetric flow rate of Center Steam supplied to a Flare, in scfm, as either measured (if applicable) or estimated using best engineering judgment, on a 5-minute block average.

(15) "Center Steam Mass Flow Rate" or "$\dot{m}_{s\text{-}cen}$" shall mean the mass flow rate of Center Steam supplied to a Flare, in pounds per hour, as either measured (if applicable) or estimated using best engineering judgment, on a 5-minute block average using Equation 2 in Appendix FLR-2 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.ii to the operating permit.

(16) "Cold Startup of the Refinery" shall mean the setting into operation of the entire Refinery after the entire Refinery has been shut down.

(17) "Combustion Efficiency" or "CE" shall mean a Flare's efficiency in converting the organic carbon compounds found in Vent Gas to carbon dioxide. Combustion Efficiency shall be determined as set forth in Equation 1 in Appendix FLR-2 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.ii to the operating permit.

(18) "Combustion Efficiency Multipliers" or "CE Multipliers" shall mean empirically-derived factors that are used as multipliers of the Net Heating Value of the Vent Gas at its Lower Flammability Limit to ensure an acceptable Combustion Efficiency. The CE Multipliers are set forth in Table 2 of Appendix FLR-3 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.iii to the operating permit, and in paragraph D.35.8.F.40.

(19) "Combustion Zone" shall mean the area of the Flare flame where the combustion of Combustion Zone Gas occurs.

(20) "Combustion Zone Gas" shall mean the mixture of all gases and steam found just after a Flare tip. This gas includes all Vent Gas, all Pilot Gas, all Total Steam (if the Flare is Steam Assisted), and all Assist Air (if the Flare is Air-Assisted).

(21) "Consent Decree" shall mean the Consent Decree entered in Civil No. 2:12-CV-00207, including any and all appendices attached hereto.

(22) "Covered Flare" shall mean each of the following Elevated, Steam-Assisted Flares at the Refinery:

Name	ID Number
VRU	241-01
FCU	230-02
Alky	140-01
4UF	224-06
UIU	220-04
South	800-04
GOHT	802-03
DDU	698-02

(23) "Discontinuous Wake Dominated Flow" shall mean gas flow exiting a Flare tip that is identified visually by:

i. the presence of a flame that is: (1) immediately adjacent to the exterior of the Flare tip body; and (2) below the exit plane of the Flare tip; and

ii. pockets of flame that are detached from the portion of the flame that is immediately adjacent to the exterior of the Flare tip body.

Representations of Discontinuous Wake Dominated Flow are set forth in Appendix FLR-13 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.xiii to the operating permit.

(24) "Elevated Flare" shall mean a Flare that supports combustion at a tip that is situated at the upper end of a vertical conveyance (e.g., pipe, duct); the

combustion zone is elevated in order to separate the heat generated by combustion from people, equipment, or structures at grade level.

(25) “Exit Velocity” shall mean the velocity (“v”) of the Vent Gas and Center Steam as it exits the flare tip. Exit Velocity shall be calculated by adding together the Vent Gas Volumetric Flow Rate and the Center Steam Volumetric Flow Rate and dividing by the Unobstructed Cross Sectional Area of the Flare Tip.

(26) “External Power Loss” shall mean a loss in the supply of electrical power to the Refinery that is caused by events occurring outside the boundaries of the Refinery, excluding power losses due to an interruptible power service agreement.

(27) “First Updated Waste Gas Minimization Plan” or “First Updated WGMP” shall mean the document submitted pursuant to Paragraph 19 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207 as the first update to the Initial WGMP.

(28) “Flare” shall mean a combustion device that uses an uncontrolled volume of ambient air to burn gases.

(29) “Flare Gas Recovery System” or “FGRS” shall mean a system of one or more compressors, piping, and associated water seal, rupture disk, or similar device used to divert gas from a Flare and direct the gas to a fuel gas system, to a combustion device other than the Flare, or to a product, co-product, by product, or raw material recovery system.

(30) “Hydrocarbon Flaring” or “HC Flaring” shall mean the combustion of refinery-generated gases, except for Acid Gas, Sour Water Stripper Gas, and/or Tail Gas, in a Hydrocarbon Flare.

(31) “Hydrocarbon Flare” or “HC Flare” shall mean a Flare used to combust any refinery-generated gas other than Acid Gas and/or Sour Water Stripper Gas and/or Tail Gas. The Hydrocarbon Flares that BPP operates at the Refinery include each of the Covered Flares and the LPG Flare. To the extent that, during the duration of the Consent Decree, BPP commences operation of any HC Flaring Devices other than or in addition to those specified herein for the purposes of combusting any excess of a refinery-generated gas other than Acid Gas and/or Sour Water Stripper Gas and/or Tail Gas, then any such flares that are: (i) Steam-Assisted shall be covered by Sections A-F, H, and J-K of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207; or (ii) Air-Assisted shall be covered by Section E, G-H, and J-K of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207. Compliance with the applicable requirements shall commence on the first date of that any such new flare receives Waste Gas from the Refinery.

(32) “Hydrocarbon Flaring Incident” or “HC Flaring Incident” shall mean either of the following:

i. “HC Flaring Incident – Trigger 1”: the continuous or intermittent combustion of refinery-generated gases, except for Acid Gas, Sour Water Stripper Gas, or Tail Gas, at a Hydrocarbon Flare that results in the emission of sulfur dioxide equal to or greater than five-hundred (500) pounds in any 24-hour period; provided, however, that if 500 pounds or more of sulfur dioxide has been emitted in any 24-hour period and flaring continues into subsequent, contiguous, non-overlapping 24-hour period(s), each period of which results in emissions equal to, or in excess of, 500 pounds of sulfur dioxide, then only one HC Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the HC Flaring Incident. When HC Flaring occurs within a 24-hour period at more than one HC Flare, the quantity of sulfur dioxide attributable to HC Flaring emitted from each HC Flare shall be added together for purposes of determining whether there is one HC Flaring Incident, unless the root causes of the flaring at the various HC Flaring Devices are not related to each other; or

ii. "HC Flaring Incident – Trigger 2": the combustion of 500,000 standard cubic feet or more of Waste Gas (excluding Acid Gas, Sour Water Stripper Gas, and Tail Gas) within a 24-hour period at a Hydrocarbon Flare. For purposes of calculating Waste Gas flow rate, the following flows may be excluded: (i) the pro-rated Baseload Waste Gas Flow Rate (pro-rated on the basis of the duration of the Flaring Incident); and (ii) if BPP has instrumentation capable of measuring the volumetric flow rate of hydrogen, nitrogen, oxygen, carbon monoxide, carbon dioxide, and/or steam in the Waste Gas, the contribution of all measured flows of any of these elements/compounds. Subsequent, contiguous, non-overlapping periods are measured from the initial commencement of Flaring within the HC Flaring Incident. When HC Flaring occurs within a 24-hour period at more than one HC Flare, the volume of Waste Gas attributable to HC Flaring emitted from each HC Flare shall be added together for purposes of determining whether there is one HC Flaring Incident, unless the root causes of the flaring at the various HC Flaring Devices are not related to each other.

(33) "Initial Waste Gas Minimization Plan" or "Initial WGMP" shall mean the document submitted pursuant to Paragraph 18 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207.

(34) "Lower Flammability Limit" or "LFL" shall mean the lowest volumetric concentration of a combustible gas in air that, at a given temperature and pressure, will still combust.

(35) "Lower Flammability Limit Table" shall mean Table 1 of Appendix FLR-3 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.iii to the operating permit. Table 1 lists, inter alia, the LFLs of individual compounds found in Vent Gas.

(36) "Lower Flammability Limit of Vent Gas" or "LFL_{vg}" shall mean the weighted average of the LFLs of each of the individual compounds in Vent Gas, weighted by their volume percent in the Vent Gas. LFL_{vg} is represented by and shall be calculated according to Equation 1 in Appendix FLR-3 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.iii to the operating permit.

(37) "Lower Heating Value" or "LHV" shall mean the theoretical total quantity of heat liberated by the complete combustion of a unit volume or weight of a fuel initially at 25° Centigrade and 760 mmHg, assuming that the produced water is vaporized and all combustion products remain at, or are returned to, 25° Centigrade; however, the standard for determining the volume corresponding to one mole is 20° Centigrade.

(38) “Lower Steam” shall mean steam piped to an exterior annular ring near the lower part of a Flare tip, which entrains Air which flows through tubes to the Flare tip, and ultimately exits the tubes at the Flare tip. Diagrams illustrating the meaning and location of Center, Lower, and Upper Steam are set forth in Appendix FLR-1 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.i to the operating permit.

(39) “LPG Flare” shall mean the Elevated, Air-Assisted Flare at the Refinery that BPP designates by ID No. 604-01.

(40) “Malfunction” shall mean any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not Malfunctions.

(41) “Minimum Steam Rate” or “Minimum Steam” shall mean the Total Steam Mass Flow Rate, in standard cubic feet per minute or in pounds per hour, recommended by the manufacturer of the Flare’s tip at the time of flare tip installation, or such lower Total Steam Mass Flow Rate as determined by the Flare tip manufacturer after Flare tip installation upon re-examination of the tip’s requirements.

(42) “Minimum Steam Reduction System” or “MSRS” shall mean a system that utilizes a mixed stream of air and steam to reduce the minimum steam requirements of a Steam-Assisted Flare.

(43) “Momentum Flux Ratio” or “MFR” shall mean the ratio of the Vent Gas and Center Steam momentum flux to the wind momentum flux, where momentum flux is the momentum per unit area, per unit time. MFR characterizes the degree to which the ambient air affects the trajectory of the Vent Gas and Center Steam just as it exits the Flare tip. MFR is represented by Equation 1 in Appendix FLR-5 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.v to the operating permit, and shall be calculated in accordance with the equations, conversion factors, MFR constants, MFR measured variables, and MFR calculated variables set forth in Attachment F.v.

(44) “Net Heating Value” shall mean Lower Heating Value.

(45) “Net Heating Value of Combustion Zone Gas” or “NHV_{cz}” shall mean the Lower Heating Value, in BTU/scf, of the Combustion Zone Gas in a Flare. NHV_{cz} is represented by Equation 5 in Appendix FLR-3 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.iii to the operating permit, and shall be calculated in accordance with Equations 5 - 8 of Attachment F.iii. To the extent a Covered Flare ever is equipped with a Minimum Steam Reduction System, BPP also shall use Equations 9 – 13 to calculate NHV_{cz}.

(46) “Net Heating Value of the Combustion Zone Gas Limit” or “$NHV_{cz\text{-}limit}$” shall mean the minimum Net Heating Value that the Combustion Zone Gas must have to ensure an acceptable Combustion Efficiency. $NHV_{cz\text{-}limit}$ shall be calculated no less than one time every 15 minutes through the use of Equation 4 in Appendix FLR-3 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.iii to the operating permit.

(47) “Net Heating Value of Hydrogen as Adjusted” or “$NHV_{H2\text{-}adj}$” shall mean 1212 BTU/scf. $NHV_{H2\text{-}adj}$ represents an adjustment to hydrogen’s actual Net Heating

Value for use, consistent with Step 3 of Appendix FLR-3 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.iii to the operating permit, in the calculation of the Net Heating Value of Vent Gas.

(48) "Net Heating Value of Vent Gas" or "NHV_{vg}" shall mean the Lower Heating Value, in BTU/scf, of the Vent Gas directed to a Flare. NHV_{vg} is calculated as set forth in Equation 2 in Appendix FLR-3 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.iii to the operating permit.

(49) "Net Heating Value of Vent Gas at its Lower Flammability Limit" or "$NHV_{vg\text{-}LFL}$" shall mean the Lower Heating Value, in BTU/scf, of the Vent Gas at its LFL. $NHV_{vg\text{-}LFL}$ is represented by and shall be calculated in accordance with Equation 3 of Appendix FLR-3 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.iii to the operating permit.

(50) "Passive FTIR" shall mean a Fourier Transform Infrared System that collects thermal (infrared) radiation emitted by a hot gas plume, and through the analysis of the resulting emission spectrum, identifies and quantifies the compounds producing values proportional to the path-integrated gas concentrations.

(51) "Pilot Gas" shall mean all gas introduced through the pilot tip of a Flare to maintain a flame.

(52) "Prevention Measure" shall mean an instrument, device, piece of equipment, system, process change, physical change to process equipment, procedure, or program to minimize or eliminate flaring.

(53) "Purge Gas" shall mean the minimum amount of gas introduced between a Flare header's water seal and the Flare tip to prevent oxygen infiltration (backflow) into the Flare tip. For a Flare with no water seal, the function of Purge Gas is performed by Sweep Gas, and therefore, by definition, such a Flare has no Purge Gas.

(54) "Refinery" shall mean the refinery that BPP owns and operates at 2815 Indianapolis Blvd, Whiting, Indiana.

(55) "Reportable Flaring Incident" shall mean each of the following: Acid Gas Flaring Incident; Tail Gas Incident; and Hydrocarbon Flaring Incident.

(56) "Root Cause Analysis" shall mean the primary and any contributing causes of a Reportable Flaring Incident as determined through a process of investigation.

(57) "SCFD" or "scfd" shall mean standard cubic feet per day.

(58) "SCFM" or "scfm" shall mean standard cubic feet per minute.

(59) "Shutdown" shall mean the cessation of operation for any purpose.

(60) "Sour Water Stripper Gas" or "SWS Gas" shall mean the gas produced by the process of stripping refinery sour water.

(61) "Smoke Emissions" shall have the definition set forth in Section 3.5 of Method 22 of 40 C.F.R. Part 60, Appendix A. Smoke Emissions may be documented by either a person certified pursuant to Method 22 or by a video camera.

(62) “SRU Flare” shall mean the Elevated Flare associated with the sulfur recovery unit at the Refinery that BPP designates with ID No. 162-03.

(63) “Standard Conditions” shall mean a temperature of 68 degrees Fahrenheit and a pressure of 1 atmosphere. Unless otherwise expressly set forth in the Consent Decree or an Appendix, Standard Conditions shall apply.

(64) “Startup” shall mean the setting in operation for any purpose.

(65) “Steam-Assisted Flare” shall mean a Flare that utilizes steam piped to a Flare tip to assist in combustion. A Flare that utilizes a Minimum Steam Reduction System is a Steam-Assisted, not an Air-Assisted, Flare.

(66) “Supplemental Gas” shall mean all gas introduced to a Flare to comply with the net heating value requirements of 40 C.F.R. § 60.18(b), 40 C.F.R. § 63.11(b), and/or paragraph D.35.8.F.33.

(67) “S/VG” or “Total-Steam-Mass-Flow-Rate-to-Vent-Gas-Mass-Flow-Rate Ratio” shall mean the ratio of the Total Steam Mass Flow Rate to the Vent Gas Mass Flow Rate.

(68) “Sweep Gas” shall mean:

i. <u>For a Flare with a Flare Gas Recovery System</u>: the minimum amount of gas introduced into a Flare header in order to: (a) prevent oxygen buildup, corrosion, and/or freezing in the Flare header; and (b) maintain a safe flow of gas through the Flare header. Sweep Gas in these Flares is introduced prior to and is intended to be recovered by the Flare Gas Recovery System;

ii. <u>For a Flare without a Flare Gas Recovery System</u>: the minimum amount of gas introduced into a Flare header in order to: (a) prevent oxygen buildup, corrosion, and/or freezing in the Flare header; (b) maintain a safe flow of gas through the Flare heater; and (c) prevent oxygen infiltration (backflow) into the Flare tip. “Tail Gas” shall mean the exhaust gas from the Claus train(s) of a sulfur recovery plant and/or from the Tail Gas Unit.

(69) “Tail Gas Incident” shall mean either of the following:

i. “Tail Gas Incident – Trigger 1”: Tail Gas that is combusted in a flare and results in excess emissions of 500 pounds or more of SO_2 in any 24-hour period; or

ii. “Tail Gas Incident – Trigger 2”: Tail Gas that is combusted in a thermal incinerator and results in excess emissions of 500 pounds or more of SO_2 emissions in any twenty-four (24) hour period. Only emissions which are in excess of a SO_2 concentration of 250 ppm (rolling twelve-hour average) shall be used to determine the amount of excess SO_2 emissions from the incinerator.

Tail Gas Incidents may include, but are not limited to, any of the following: a TGU shutdown, a TGU bypass, and a scheduled or unscheduled shutdown of a sulfur recovery plant. For Tail Gas Incidents – Trigger 2, BPP shall use good engineering judgment and/or other monitoring data to calculate emissions during periods in which the SO_2 continuous emission analyzer has exceeded the range of the instrument or the instrument is out of service.

(70) "Tail Gas Unit" or "TGU" shall mean a control system utilizing a technology for reducing emissions of sulfur compounds from a sulfur recovery plant.

(71) "Temporary-Use Flare" shall mean a flare that receives Waste Gas that has been redirected to it from another flare for 504 hours or less on a rolling 1095 day average period.

(72) "Total Steam" or "S" shall mean the total of all steam that intentionally is introduced into a Steam-Assisted Flare to assist in combustion. Total Steam includes, but is not limited to, Lower Steam, Center Steam, and Upper Steam.

(73) "Total Steam Volumetric Flow Rate" or "Q_s" shall mean the volumetric flow rate of Total Steam supplied to a Flare, in scfm as measured on a 5-minute block average.

(74) "Total Steam Mass Flow Rate" or "$\dot{m}_s$" shall mean the mass flow rate of Total Steam supplied to a Flare, in pounds per hour as calculated on a 5-minute block average. Total Steam Mass Flow Rate shall be calculated as set forth in Equation 3 in Appendix FLR-2 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.ii to the operating permit.

(75) "Unobstructed Cross Sectional Area of the Flare Tip" or "$A_{tip-unob}$" shall mean the open, unobstructed area of a Flare tip through which Vent Gas and Center Steam pass. Diagrams of four common flare types are set forth in Appendix FLR-6 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.vi to the operating permit, together with the equations for calculating the $A_{tip-unob}$ of these four types.

(76) "Upper Steam," sometimes called Ring Steam, shall mean steam piped to nozzles located on the exterior perimeter of the upper end of a Flare tip. Diagrams illustrating the meaning and location of Center, Lower, and Upper Steam are set forth in Appendix FLR-1 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.i to the operating permit.

(77) "Variable Speed Motor" shall mean a motor that operates at continuously variable speeds between a minimum and maximum as regulated by a Variable Speed Drive.

(78) "Variable Speed Drive" shall mean a piece of equipment that regulates the speed and rotational force, or torque output, of an electric motor and that outputs a variable frequency to a motor to allow it to operate at variable speeds between the motor's minimum and maximum speed.

(79) "Velocity of the Wind" or "v_{wind}" shall mean the velocity of the ambient air, in ft/s on a one-minute block average, measured at the Meteorologic Station required pursuant to paragraph D.35.8.B.12.

(80) "Vent Gas" shall mean the mixture of all gases found prior to the Flare tip. This gas includes all Waste Gas, Sweep Gas, Purge Gas, and Supplemental Gas, but does not include Pilot Gas, Total Steam, or Assist Air.

(81) "Vent Gas Volumetric Flow Rate" or "Q_{vg}" shall mean the volumetric flow rate of Vent Gas directed to a Covered Flare, in wet scfm, on a 5-minute block average basis.

(82) "Vent Gas Mass Flow Rate" or "$\dot{m}_{vg}$" shall mean the mass flow rate of Vent Gas directed to a Covered Flare, in pounds per hour on a 5-minute block average. Vent Gas Mass Flow Rate shall be calculated as set forth in Equation 4 in Appendix FLR-2 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.ii to the operating permit.

(83) "Vent Gas Molecular Weight" or "MW_{vg}" shall mean the Molecular Weight, in pounds per pound-mole, of the Vent Gas, on a 5-minute block average.

(84) "Visible Emissions" shall mean five minutes or more during any two consecutive hours of Smoke Emissions. For purposes of this Appendix, Visible Emissions may be documented by either a person certified pursuant to Method 22 or by a video camera.

(85) "VOC" or "Volatile Organic Compounds" shall have the definition set forth in 40 C.F.R. Section 51.100(s).

(86) "VOC Vent Gas Concentration" shall mean the volumetric concentration of VOCs in the Vent Gas and shall be calculated as set forth in Equation 16 of Table 2 of Appendix FLR-3 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.iii to the operating permit.

(87) "Waste Gas" shall mean the mixture of all gases from facility operations that is directed to a flare for the purpose of disposing of the gas. "Waste Gas" does not include gas introduced to a flare exclusively to make it operate safely and as intended; therefore, "Waste Gas" does not include Pilot Gas, Total Steam, Assist Air, or the minimum amount of Sweep Gas and Purge Gas that is necessary to perform the functions of Sweep Gas and Purge Gas. "Waste Gas" also does not include gas introduced to a flare to comply with regulatory requirements; therefore, "Waste Gas" does not include Supplemental Gas. Depending upon the instrumentation that measures Waste Gas, certain compounds (hydrogen, nitrogen, oxygen, carbon dioxide, carbon monoxide, and/or water (steam)) that are directed to a Flare for the purpose of disposing of these compounds may be excluded from calculations relating to Waste Gas flow; in the substantive provisions of this Appendix, the circumstances in which such exclusions are permitted are specifically identified. Appendix FLR-7 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.vii to the operating permit, depicts the meaning of "Waste Gas," together with its relation to other gases associated with Flares.

(88) "BPP" means BP Products North America Inc.

C.25 Emission Credit Generation

(a) Prohibitions on Emission Credits.

(1) General Prohibition. BPP shall not generate or use any NOx, SO_2, H_2S, TRS, reduced sulfur compounds, PM, $PM_{2.5}$, PM_{10}, PM_{TOTAL}, VOC, or CO emissions reductions ("CD Emission Reductions"), or apply for and obtain any emission reduction credits, that result from any projects conducted or controls utilized pursuant to the Consent Decree entered in Civil No. 2:12 CV 207 as netting

reductions or emissions offsets in any PSD, major non-attainment, and/or minor New Source Review permit or permit proceeding.

(2) Specific Prohibition on Reductions under 2001 Consent Decree (Civ. No. 2:96 CV 095 RL). BPP shall not generate or use any NOx emission reductions, or apply for and obtain any NOx emission reduction credits, that are achieved as a result of the following projects required by the 2001 Consent Decree as netting reductions or emissions offsets in any PSD, major nonattainment, and/or minor New Source Review permit or permit proceeding:

3 Stanolind Power Station Boilers 31, 32, 33, 34 and 36	Installation of SCRs	Completed December 31, 2010
1 Stanolind Power Station Boilers 13, 14, 16 and 17	Shutdown	Completed April 1, 2010

(b) Exception to Prohibitions on Emission Credits. Notwithstanding the prohibitions set forth in Paragraph (a), BPP may use 8 tons per year (tpy) of VOC, 26 tpy of NOx, 6 tpy of PM_{10}, and 18 tpy of CO from emissions reductions required by the Consent Decree entered in Civil No. 2:12-CV-00207 or the 2001 Consent Decree (Civ. No. 2:96 CV 095 RL) as credits or offsets in any PSD, major non-attainment and/or minor NSR permit or permit proceeding occurring after the Date of Lodging of the Consent Decree at the Whiting Refinery; provided that the new, modified or affected emissions units for which credits are being used: (1) is being constructed, modified or affected for purposes of compliance with Tier III Vehicle Emission and Fuel Standards; and (2) has a federally enforceable, non-Title V Permit (i.e, a permit issued pursuant to the State of Indiana's consolidated Title V construction and operating permit program) that reflects the following requirements that are applicable to the pollutants for which credits are being used:

(1) For heaters and boilers, a limit of 0.027 lbs. NOx per million BTU on a 3-hour rolling average basis.

(2) For heaters and boilers, a limit of 0.10 grains of H_2S per dry standard cubic foot of fuel gas or 20 ppmvd SO_2 corrected to 0% O_2 both on a 3- hour rolling average basis.

(c) For heaters and boilers, no liquid or solid fuel firing authorization.

(4) For FCCUs, a limit of 20 ppmvd NOx corrected to 0% O_2 on a 365-day rolling average basis.

(5) For FCCUs, a limit of 25 ppmvd SO_2 corrected to 0% O_2 on a 365- day rolling average basis.

(6) For FCCUs, a limit of 0.5 pounds of PM per 1,000 pounds of coke burned on a 3-hour average basis.

(7) For SRPs, a limit of 100 ppmvd SO_2 at 0% O_2 on a 24-hour rolling average basis.

(c) Conditions Precedent to Utilizing Exception to General Prohibition. Utilization of the exception set forth in paragraph (b) to the general prohibition against the generation or utilization of CD Emissions Reductions set forth in paragraph (a) is subject to the following conditions:

(1) Under no circumstances shall BPP use CD Emissions Reductions for netting and/or offsets prior to the time that actual CD Emissions Reductions have occurred.

(2) CD Emissions Reductions may be used only at the Whiting Refinery.

(3) The CD Emissions Reductions provisions of the Consent Decree entered in Civil No. 2:12-CV-00207 are for purposes of this Consent Decree only and neither BPP nor any other entity may use CD Emissions Reductions for any purpose, including in any subsequent permitting or enforcement proceeding, except as provided herein.

(4) BPP still shall be subject to all federal, state and local regulations applicable to the PSD, major non-attainment and/or minor NSR permitting process.

(d) Outside the Scope of the General Prohibition. Nothing in this Condition is intended to prohibit BPP from seeking to, or IDEM from denying BPP's request to:

(1) Utilize or generate emissions credits from refinery units that are covered by the Consent Decree entered in Civil No. 2:12-CV-00207 to the extent that the proposed credits or reductions represent the difference between the emissions limitations set forth in or required by this Consent Decree for these refinery units and the more stringent emissions limitations that BPP may elect to accept for these refinery units in a permitting process.

(2) Utilize or generate emissions credits or reductions on refinery units that are not subject to an emission limitation pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207.

(3) Utilize emissions reductions pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207 for the Whiting Refinery's compliance with any rules or regulations designed to address regional haze or the non-attainment status of any area (excluding PSD and Non-Attainment New Source Review Rules, but including, for example, RACT rules) that apply to the Whiting Refinery. Notwithstanding the preceding sentence, BPP will not trade or sell any emissions reductions that result from any projects conducted or controls utilized pursuant to this Consent Decree.

SECTION D.0 EMISSIONS UNIT OPERATION CONDITIONS

Emissions Unit Description: Source Wide Conditions

(The information describing the process contained in this emissions unit 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 [326 IAC 2-7-5(1)]

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.01 EMISSIONS UNIT OPERATION CONDITIONS - Cat Feed Hydrotreating Unit and Gas Oil Hydrotreater 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 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

(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

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

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

D.01.1 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 2-2 not applicable, the Permittee shall comply with the following:

(a) Pursuant to SSM 089-32033-00453 as modified by SPM 089-40517-00453, the Permittee shall comply with the following limits following the completion of the WRMP project:

Unit ID	Firing rate (10^3 MMBtu)	SO_2 (tons)	NOx (tons)	CO (tons)
F-801A F-801B F-801C F-901A F-901B	1,592.15	8.80	33.03	39.89

All limits per twelve (12) consecutive month period with compliance determined at the end of each month.

Additional limits on PM, PM_{10}, SO_2, and VOC for the CFHU heaters (F-801A, F-801B, and F-801C) are in Section D.19.

Additional limits on PM, PM_{10}, NOx, and VOC for the GOHT heaters (F-901A and F-901B) are in Section D.42.

Compliance with the limits on the annual firing rates and the SO_2, NOx, and CO 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 SO_2, NOx, and CO 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.

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

D.01.2 Compliance Determination Requirements - CFHU & GOHT

Pursuant to SPM 089-40517-00453, the following equations shall be used to determine compliance with the firing rate limit, SO_2 limit, NOx limit, and CO limit in Condition D.01.1. Compliance is demonstrated each month by adding the combined firing rate or emissions for that month to the firing rate or emissions for the preceding eleven (11) months.

(a) Firing rate:

$$Q = Q_{CFHU} + Q_{F901A} + Q_{F901B}$$

Where:

Q = combined firing rate for CFHU heaters and GOHT heaters, 10^3 MMBtu/month
Q_{CFHU} = Greater of $Q_{F801A} + Q_{F801B} + Q_{F801C}$ or 16.38 (10^3 MMBtu/month)
Q_{F801A} = firing rate for F-801A heater, 10^3 MMBtu/month
Q_{F801B} = firing rate for F-801B heater, 10^3 MMBtu/month
Q_{F801C} = firing rate for F-801C heater, 10^3 MMBtu/month
Q_{F901A} = firing rate for F-901A heater, 10^3 MMBtu/month
Q_{F901B} = firing rate for F-901B heater, 10^3 MMBtu/month

(b) Sulfur dioxide:

$$S = S_{CFHU} + S_{F901A} + S_{F901B}$$

Where:

S = combined SO_2 emissions for CFHU heaters and GOHT heaters, tons/month
S_{CFHU} = Greater of $S_{F801A} + S_{F801B} + S_{F801C}$ or 0.064 (tons/month)
S_{F801A} = SO_2 emissions for F-801A heater, tons/month

S_{F801B} = SO_2 emissions for F-801B heater, tons/month
S_{F801C} = SO_2 emissions for F-801C heater, tons/month
S_{F901A} = SO_2 emissions for F-901A heater, tons/month
S_{F901B} = SO_2 emissions for F-901B heater, tons/month

Monthly SO_2 emissions for each unit shall be determined from the continuous emissions monitoring required by Conditions D.19.11 and D.42.9 for refinery fuel gas, or natural gas emission factor and monthly firing rate.

(c) NOx:

$$N = N_{CFHU} + N_{F901A} + N_{F901B}$$

Where:

N = combined NOx emissions for CFHU heaters and GOHT heaters, tons/month
N_{CFHU} = Greater of $N_{F801A} + N_{F801B} + N_{F801C}$ or 0.40 (tons/month)
N_{F801A} = NOx emissions for F-801A heater, tons/month
N_{F801B} = NOx emissions for F-801B heater, tons/month
N_{F801C} = NOx emissions for F-801C heater, tons/month
N_{F901A} = NOx emissions for F-901A heater, tons/month
N_{F901B} = NOx emissions for F-901B heater, tons/month

Monthly NOx emissions for each unit shall be determined from the results of performance testing required by Conditions D.19.10 and D.42.8 and monthly firing rate.

(d) CO:

$$C = C_{CFHU} + C_{F901A} + C_{F901B}$$

Where:

C = combined CO emissions for CFHU heaters and GOHT heaters, tons/month
C_{CFHU} = Greater of $C_{F801A} + C_{F801B} + C_{F801C}$ or 0.68 (tons/month)
C_{F801A} = CO emissions for F-801A heater, tons/month
C_{F801B} = CO emissions for F-801B heater, tons/month
C_{F801C} = CO emissions for F-801C heater, tons/month
C_{F901A} = CO emissions for F-901A heater, tons/month
C_{F901B} = CO emissions for F-901B heater, tons/month

Monthly CO emissions for each unit shall be determined from the results of performance testing required by Condition D.19.10 and D.42.8 and monthly firing rate.

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

D.01.3 Record Keeping Requirements

(a) In order to document the compliance status with Condition D.01.1, the Permittee shall maintain records of monthly firing rates, monthly emissions of SO_2, monthly emissions of NOx, and monthly emissions of CO from the following units:

F-801A
F.801B
F-801C

F-901A
F-901B

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

D.01.4 Reporting Requirements

(a) In order to document the compliance status with Condition D.01.1, the Permittee shall submit a quarterly summary of the following for the CFHU heaters (F-801A, F-801B, and F-801C) and GOHT heaters (F-901A and F-901B) not later than thirty (30) days after the end of the quarter being reported:

(1) Combined monthly firing rate (10^3 MMBtu/month)
(2) Combined monthly SO_2 emissions (tons/month)
(3) Combined monthly NOx emissions (tons/month)
(4) Combined monthly CO emissions (tons/month)

(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.02 EMISSIONS UNIT OPERATION CONDITIONS – TGU, FCU, and 3SPS Particulate Limits

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:

(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.

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

(1) One (1) catalyst regenerator. Flue gas from the regenerator passes through an ammonia injection system, a waste heat recovery unit which generates steam, an Electrostatic Precipitator for particulate matter control, and is exhausted through stack S/V 230-01. The ammonia injection system includes aqueous ammonia injection and handling equipment. Aqueous ammonia is transferred from the FCU 600 SCR system's storage tanks. Stack S/V 230-01 has continuous emissions monitors (CEMS) for NO_X, SO_2, CO and O_2.

(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°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.

(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) Five (5) Boilers, each approved in 2008 for modification as a contemporary project to the WRMP project, each equipped with conventional burners, a Selective Catalytic

Reduction (SCR) system, and a direct-fired Duct Burner. Each direct-fired Duct Burner rated at 41 mmBTU/hr, equipped with low-NOx burners, and controlled by the Selective Catalytic Reduction (SCR) system. Each stack equipped with continuous emissions monitors (CEMS) for NOx and CO:

Boiler and Duct Burner Identification	Maximum Heat Input Capacity (mmBTU/hr)	Installation Date	Modification Date	Emissions Control	Stack Exhausted To
#31 Boiler	575	1948	2010	SCR	503-01 (NOx & CO CEMS)
#31 Duct Burner	41	2010	--		
#32 Boiler	575	1948	2010	SCR	503-02 (NOx & CO CEMS)
#32 Duct Burner	41	2010	--		
#33 Boiler	575	1951	2010	SCR	503-03 (NOx & CO CEMS)
#33 Duct Burner	41	2010	--		
#34 Boiler	575	1951	2010	SCR	503-04 (NOx & CO CEMS)
# 34 Duct Burner	41	2010	--		
#36 Boiler	575	1953	2011	SCR	503-05 (NOx & CO CEMS)
#36 Duct Burner	41	2011	--		

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

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

D.02.1 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 2-1.1-4, 326 IAC 2-2, and 326 IAC 2-3 not applicable, the Permittee shall comply with the following:

(a) Pursuant to Significant Source Modification No. 089-25484-00453, issued on May 1, 2008, modified by Significant Permit Modification No. 089-31849-00453, issued on December 20, 2012, Significant Permit Modification No. 089-36656-00453, issued on June 14, 2016, and Significant Permit Modification No. 089-43173-00453, the Permittee shall comply with the following limits:

Unit ID	PM^1 (tons)	$PM_{10}{}^1$ (tons)
TGU A and TGU B	796.66	494.99
FCU 500		
FCU 600		
3SPS Boiler SCR on stacks 503-01, 503-02, 503-03, 503-04, and 503-05		
3SPS Duct Burners on stacks 503-01, 503-02, 503-04, 503-03, and 503-05		

Notes:

1. *Limits are per twelve (12) consecutive month period with compliance determined at the end of each month.*

Additional requirements regarding firing rate, PM, PM_{10}, NOx, VOC, SO_2, and, CO for the SRP (TGU A and TGU B) are in Section D.4.

Additional requirements regarding coke burned, fresh feed, PM_{TOTAL}, PM_{10}, NOx, VOC, SO_2, and CO for the FCU 500 are in Section D.21

Additional requirements regarding coke burned, fresh feed, PM_{TOTAL}, PM_{10}, NOx, VOC, SO2, and CO for the FCU 600 are in Section D.22.

Additional requirements regarding firing rate, NOx, VOC, and CO for the 3SPS duct burners and boiler SCRs (identified as limits on stacks 503-01, 503-02, 503-03, 503-04, and 503-05) are in Section D.24.

Compliance with the 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 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

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

D.02.2 Compliance Determination Requirements

Pursuant to SPM 089-43173-00453, the following equations shall be used to determine compliance with the PM and PM_{10} limits in Condition D.02.1.

(a) The following equations shall be used to determine compliance with the PM limit for the Claus offgas treater tail gas units A and B

(1)

$$PM_{TGU\ A} = \frac{ER_{TGU\ A} \times H_{TGU\ A}}{2{,}000\ \text{lb/ton}}$$

Where:

$PM_{TGU\ A}$ = PM emissions of TGU A, tons/month
$ER_{TGU\ A}$ = PM emission rate of TGU A, lb/hr, determined in the most recent test required by Condition D.4.9(a)
$H_{TGU\ A}$ = Monthly hours of operation of TGU A, hr/month

(2)

$$PM_{TGU\ B} = \frac{ER_{TGU\ B} \times H_{TGU\ B}}{2{,}000\ \text{lb/ton}}$$

Where:

$PM_{TGU\ B}$ = PM emissions of TGU B, tons/month
$ER_{TGU\ B}$ = PM emission rate of TGU B, lb/hr, determined in the most recent test required by condition D.4.9(b)
$H_{TGU\ B}$ = Monthly hours of operation of TGU B, hr/month

(3)

$$PM_{TGU\ An} = \sum_{i=1}^{12} (PM_{TGU\ A} + PM_{TGU\ B})_i$$

Where:

$PM_{TGU\ An}$ = Total combined PM emissions of TGU A and TGU B, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

(b) The following equations shall be used to determine compliance with the PM limit for fluid catalytic cracking unit 500:

(1)

$$PM_{FCU\ 500} = \frac{EF_{FCU\ 500} \times C_{FCU\ 500}}{2{,}000\ \text{lb/ton}}$$

Where:

$PM_{FCU\ 500}$ = PM emissions of FCU 500, tons/month
$EF_{FCU\ 500}$ = PM_{TOTAL} emission rate of FCU 500, lb/1,000 lb of coke burned, determined in the most recent test required by Condition D.21.10.
$C_{FCU\ 500}$ = Amount of coke burned in FCU 500, lb/month

(2)

$$PM_{FCU\ 500\ An} = \sum_{i=1}^{12} (PM_{FCU\ 500})_i$$

Where:

$PM_{FCU\ 500\ An}$ = Total PM emissions of FCU 500, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

However, the value of $PM_{FCU\ 500\ An}$ shall not be less than 117.20 tons per twelve (12) consecutive month period.

(c) The following equations shall be used to determine compliance with the PM limit for fluid catalytic cracking unit 600:

(1)

$$PM_{FCU\ 600} = \frac{EF_{FCU\ 600} \times C_{FCU\ 600}}{2{,}000\ \text{lb/ton}}$$

Where:

$PM_{FCU\ 600}$ = PM emissions of FCU 600, tons/month
$EF_{FCU\ 600}$ = PM_{TOTAL} emission rate of FCU 600, lb/1,000 lb of coke burned, determined in the most recent test required by Condition D.22.10.
$C_{FCU\ 600}$ = Amount of coke burned in FCU 600, lb/month

(2)

$$PM_{FCU\ 600\ An} = \sum_{i=1}^{12} (PM_{FCU\ 600})_i$$

Where:

$PM_{FCU\ 600\ An}$ = Total PM emissions of FCU 600, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

However, the value of $PM_{FCU\ 600\ An}$ shall not be less than 56.30 tons twelve (12) consecutive month period.

(d) The following equations shall be used to determine compliance with the PM limit for the No. 3 SPS:

(1)

$$PM_{3SPS\ SCR} = PM_{3SPS\ Boiler\ Stack} - PM_{3SPS\ Boiler}$$

Where:

$PM_{3SPS\ SCR}$ = PM emissions of No. 3 SPS boiler SCR system, tons/month
$PM_{3SPS\ Boiler\ Stack}$ = sum of boiler stack emissions, tons/month
$PM_{3SPS\ Boiler}$ = sum of boiler emissions, tons/month

And:

$$PM_{3SPS\ Boiler\ Stack} = \frac{\sum_{j=1}^{5} R_{PM\text{-}j}\ Q_{Bj}}{2{,}000\ lb/ton}$$

And:

$$PM_{3SPS\ Boiler} = \frac{\sum_{j=1}^{5} R_{B\text{-}j}\ Q_{Bj}}{2{,}000\ lb/ton}$$

Thus:

$$PM_{3SPS\ SCR} = \frac{\sum_{j=1}^{5} \left(R_{PM\text{-}j} - R_{B\text{-}j}\right) Q_{Bj}}{2{,}000\ lb/ton}$$

Where:

j = counter for stack ID's, 503-0*j*
$R_{PM\text{-}j}$ = Most recent PM test result for stack 503-0j, lb/MMBtu. These values shall be calculated based on the average of the valid test runs using for each test run the average PM test result for stack 503-0j in lb/hr divided by the average hourly heat input of the boilers and duct burners calculated in accordance with section (k). Until the results of tests required by Condition D.02.3 are available, the source shall use the following values of $R_{PM\text{-}j}$:

j	Date	Unit	$R_{PM\text{-}j}$
1	11/16/2021	31	0.0014
2	10/9/2018	32	0.0044
3	10/11/2018	33	0.0063
4	10/12/2018	34	0.0062
5	4/16/2019	36	0.0014

$R_{B\text{-}j}$ = Most recent PM test result for a boiler exhausting to the stack 503-0j, lb/MMBtu, calculated based on the average of the valid test runs using for each test run the average PM test result for stack 503-0j in lb/hr divided by the average hourly heat input of the boiler calculated in accordance with section (k). Until the results of tests required by Condition D.02.3 are available, $R_{B\text{-}j}$ = 0.0019 lb/MMBtu.

However, the value of $R_{B\text{-}j}$ shall not be greater than 0.0019 lb/MMBtu.

Q_{Bj} = Combined firing rate for all fuels in the boiler exhausting to stack 503-0j, MMBtu/month based on the average monthly heat input of the boiler calculated in accordance with section (k).
Note that boilers 31-34 exhaust to stacks 503-01 through 503-04, respectively and boiler 36 exhausts to stack 503-05

(2)

$$PM_{3SPS\ DB} = \frac{\sum_{j=1}^{5} R_{PM\text{-}j}\ Q_{Dj}}{2{,}000\ \text{lb/ton}}$$

Where:

$PM_{3SPS\ DB}$ = PM emissions of No. 3 SPS duct burners, tons/month
j = counter as in paragraph (1)
$R_{PM\text{-}j}$ = as in paragraph (1)
Q_{Dj} = Combined firing rate for all fuels in the duct burner exhausting to stack 503-0*j*, MMBtu/month based on the average monthly heat input of the duct burner calculated in accordance with section (k).

Note that duct burners 31-34 exhaust to stacks 503-01 through 503-04, respectively and duct burner 36 exhausts to stack 503-05

(3)

$$PM_{3SPS\ An} = \sum_{i=1}^{12} (PM_{3SPS\ SCR} + PM_{3SPS\ DB})_i$$

Where:

$PM_{3SPS\ An}$ = Total combined PM emissions of No. 3 SPS, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

(e) The following equation shall be used to determine compliance with the combined PM limit for the Claus offgas treater tail gas units A and B, fluid catalytic cracking units 500 and 600, and No. 3 SPS boiler and duct burners in Condition D.02.1(a):

$$PM_{An} = PM_{TGU\ An} + PM_{FCU\ 500\ An} + PM_{FCU\ 600\ An} + PM_{3SPS\ An}$$

Where:

PM_{An} = Total PM emissions of the units, tons per twelve (12) consecutive month period
$PM_{TGU\ An}$ = determined in paragraph (a)(3)
$PM_{FCU\ 500\ An}$ = determined in paragraph (b)(2)
$PM_{FCU\ 600\ An}$ = determined in paragraph (c)(2)
$PM_{3SPS\ An}$ = determined in paragraph (d)(3)

(f) The following equations shall be used to determine compliance with the PM_{10} limit for the Claus offgas treater tail gas units A and B

(1)

$$PM_{10\ TGU\ A} = \frac{ER_{10\ TGU\ A} \times H_{TGU\ A}}{2{,}000\ lb/ton}$$

Where:

$PM_{10\ TGU\ A}$ = PM_{10} emissions of TGU A, tons/month
$ER_{10\ TGU\ A}$ = PM_{10} emission rate of TGU A, lb/hr, determined in the most recent test required by Condition D.4.9(a).
$H_{TGU\ A}$ = Monthly hours of operation of TGU A, hr/month

(2)

$$PM_{10\ TGU\ B} = \frac{ER_{10\ TGU\ B} \times H_{TGU\ B}}{2{,}000\ lb/ton}$$

Where:

$PM_{10\ TGU\ B}$ = PM_{10} emissions of TGU B, tons/month
$ER_{10\ TGU\ B}$ = PM_{10} emission rate of TGU B, lb/hr, determined in the most recent test required by Condition D.4.9(b).
$H_{TGU\ B}$ = Monthly hours of operation of TGU B, hr/month

(3)

$$PM_{10\ TGU\ An} = \sum_{i=1}^{12} (PM_{10\ TGU\ A} + PM_{10\ TGU\ B})_i$$

Where:

$PM_{10\ TGU\ An}$ = Total combined PM_{10} emissions of TGU A and TGU B, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

(g) The following equations shall be used to determine compliance with the PM_{10} limit for fluid catalytic cracking unit 500:

(1)

$$PM_{10\ FCU\ 500} = \frac{EF_{10\ FCU\ 500} \times C_{FCU\ 500}}{2{,}000\ lb/ton}$$

Where:

$PM_{10\ FCU\ 500}$ = PM_{10} emissions of FCU 500, tons/month
$EF_{10\ FCU\ 500}$ = PM_{10} emission rate of FCU 500, lb/1,000 lb of coke burned, determined in the most recent test required by Condition D.21.10.
$C_{FCU\ 500}$ = Amount of coke burned in FCU 500, lb/month

(2)

$$PM_{10\ FCU\ 500\ An} = \sum_{i=1}^{12} (PM_{10\ FCU\ 500})_i$$

Where:

$PM_{10\ FCU\ 500\ An}$ = Total PM_{10} emissions of FCU 500, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

However, the value of $PM_{10\ FCU\ 500\ An}$ shall not be less than 117.20 tons per twelve (12) consecutive month period.

(h) The following equations shall be used to determine compliance with the PM_{10} limit for fluid catalytic cracking unit 600:

(1)

$$PM_{10\ FCU\ 600} = \frac{EF_{10\ FCU\ 600} \times C_{FCU\ 600}}{2{,}000\ \text{lb/ton}}$$

Where:

$PM_{10\ FCU\ 600}$ = PM_{10} emissions of FCU 600, tons/month
$EF_{10\ FCU\ 600}$ = PM_{10} emission rate of FCU 600, lb/1,000 lb of coke burned, determined in the most recent test required by Condition D.22.10.
$C_{FCU\ 600}$ = Amount of coke burned in FCU 600, lb/month

(2)

$$PM_{10\ FCU\ 600\ An} = \sum_{i=1}^{12} (PM_{10\ FCU\ 600})_i$$

Where:

$PM_{10\ FCU\ 600\ An}$ = Total PM_{10} emissions of FCU 600, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

However, the value of $PM_{10\ FCU\ 600\ An}$ shall not be less than 56.30 tons per twelve (12) consecutive month period.

(i) The following equations shall be used to determine compliance with the PM_{10} limit for the No. 3 SPS:

(1)

$$PM_{10\ 3SPS\ SCR} = PM_{10\ 3SPS\ Boiler\ Stack} - PM_{10\ 3SPS\ Boiler}$$

Where:

$PM_{10\ 3SPS\ SCR}$ = PM_{10} emissions of No. 3 SPS boiler SCR system, tons/month
$PM_{10\ 3SPS\ Boiler\ Stack}$ = sum of boiler stack emissions, tons/month
$PM_{10\ 3SPS\ Boiler}$ = sum of boiler emissions, tons/month

And:

$$PM_{10\ 3SPS\ Boiler\ Stack} = \frac{\sum_{j=1}^{5} R_{PM10\text{-}j}\ Q_{Bj}}{2{,}000\ lb/ton}$$

And:

$$PM_{10\ 3SPS\ Boiler} = \frac{\sum_{j=1}^{5} R_{B10\text{-}j}\ Q_{Bj}}{2{,}000\ lb/ton}$$

Thus:

$$PM_{10\ 3SPS\ SCR} = \frac{\sum_{j=1}^{5} \left(R_{PM10\text{-}j} - R_{B10\text{-}j}\right) Q_{Bj}}{2{,}000\ lb/ton}$$

Where:

j = counter for stack ID's, 503-0*j*

$$R_{PM10\text{-}j} = \sum_{j=1}^{5} \left(R_{CPM\text{-}j} + R_{PM\text{-}j}\right)$$

Where:

$R_{PM\text{-}j}$ = PM emission rate for the stack 503-0j, lb/MMBtu, calculated in accordance with section (d)(1)

$$R_{CPM\text{-}j} = (A \times S + B) \times CSF$$

$R_{CPM\text{-}j}$ = Condensible PM_{10} emission rate for the stack 503-0j, lb/MMBtu

S = Average monthly total sulfur content of fuels, calculated as H2S, combusted by the boiler and duct burner, ppm

A = Constant, in lb/MMBtu-ppm, determined after submittal of each stack test required by Condition D.02.3, rounded to two significant digits. Until the results of the tests required by Condition D.0.2.3(b) the value of 0.00021 lb/MMBtu-ppm shall be used.

B = Constant, in lb/MMBtu, determined after submittal of each stack test required by Condition D.02.3, rounded to two significant digits. Until the results of the tests required by Condition D.0.2.3(b) the value of 0.0059 lb/MMBtu shall be used.

CSF = Constant, conditional safety factor. Starting with issuance of SPM No. 089-45450-00453, and after each boiler and duct burner combination has been tested in accordance with D.02.3(a)(5), if the monthly average ammonia injection rate (lb/hr) is greater than the value determined in accordance D.02.3(a)(5), CSF shall be equal to a safety factor of 1.3. Otherwise, CSF shall be equal to 1.

Constants A and B shall be based on a linear regression of the condensible PM_{10}, in lb/MMBtu, for all valid condensable PM_{10} tests of all of the 3SPS Boilers (stacks identified as 503-1 through 503-5) calculated based on the average of the valid test runs using the average condensable PM_{10} test result for stack 503-0j in lb/hr divided by the average hourly heat input of the boiler calculated in accordance with section (k) and the hourly average fuel sulfur content, calculated as H2S, in ppm, for all fuels burned during the associated test runs.

Boiler / DB	Test Date	CPM	Fuel Gas Total Sulfur
		lb/MMBtu	(ppm)
Boiler / DB 32	8/3/2015	0.018	43
Boiler / DB 36	8/5/2015	0.016	55
Boiler / DB 32	10/20/2015	0.019	64
Boiler / DB 32	1/28/2016	0.020	66
Boiler / DB 36	11/2/2016	0.023	89
Boiler / DB 31	10/8/2018	0.013	37
Boiler / DB 32	10/9/2018	0.015	32
Boiler / DB 33	10/11/2018	0.012	25
Boiler / DB 34	10/12/2018	0.008	21
Boiler / DB 36	4/16/2019	0.011	34
Boiler / DB 31	11/16/2021	0.012	34
Slope (A)		0.00021 lb/MMBtu-ppm	
Y-Intercept (B)		0.0059 lb/MMBtu	

$R_{B10\text{-}j}$ = Most recent PM_{10} test result for a boiler exhausting to the stack 503-0j, lb/MMBtu calculated based on the average of the valid test runs using the average PM10 test result for stack 503-0j in lb/hr divided by the average hourly heat input of the boiler calculated in accordance with section (k). Until the results of tests required by Condition D.02.3 are available, $R_{B10\text{-}j}$ = 0.0075 lb/MMBtu.

However, the value of $R_{B10\text{-}j}$ shall not be greater than 0.0075 lb/MMBtu.

Q_{Bj} = Combined firing rate for all fuels in the boiler exhausting to stack 503-0j, MMBtu/month based on the average monthly heat input of the boiler calculated in accordance with section (k).

Note that boilers 31-34 exhaust to stacks 503-01 through 503-04, respectively and boiler 36 exhausts to stack 503-05

(2)

$$PM_{10\ 3SPS\ DB} = \frac{\sum_{j=1}^{5} R_{PM10\text{-}j}\ Q_{Dj}}{2{,}000\ \text{lb/ton}}$$

Where:

$PM_{10\ 3SPS\ DB}$ = PM_{10} emissions of No. 3 SPS duct burners, tons/month
j = counter as in paragraph (1)
$R_{PM10\text{-}j}$ = as in paragraph (1)
Q_{Dj} = Combined firing rate for all fuels in the duct burner exhausting to stack 503-0*j*, MMBtu/month based on the average monthly heat input of the duct burner calculated in accordance with section (k).

Note that duct burners 31-34 exhaust to stacks 503-01 through 503-04, respectively and duct burner 36 exhausts to stack 503-05

(3)

$$PM_{10\ 3SPS\ An} = \sum_{i=1}^{12} (PM_{10\ 3SPS\ SCR} + PM_{10\ 3SPS\ DB})_i$$

Where:

$PM_{10\ 3SPS\ An}$ = Total combined PM_{10} emissions of No. 3 SPS, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

(j) The following equation shall be used to determine compliance with the combined PM_{10} limit for the Claus offgas treater tail gas units A and B, fluid catalytic cracking units 500 and 600, and No. 3 SPS boiler and duct burners in Condition D.02.1(a):

$$PM_{10\ An} = PM_{10\ TGU\ An} + PM_{10\ FCU\ 500\ An} + PM_{10\ FCU\ 600\ An} + PM_{10\ 3SPS\ An}$$

Where:

$PM_{10\ An}$ = Total PM_{10} emissions of the units, tons per twelve (12) consecutive month period
$PM_{10\ TGU\ An}$ = determined in paragraph (f)(3)
$PM_{10\ FCU\ 500\ An}$ = determined in paragraph (g)(2)
$PM_{10\ FCU\ 600\ An}$ = determined in paragraph (h)(2)
$PM_{10\ 3SPS\ An}$ = determined in paragraph (i)(3)

(k) For the purposes of calculating the heat input in sections (d) and (i), when combusting refinery fuel gas in the boilers and duct burners, the Permittee shall continuously analyze the higher heating value (HHV) of the refinery fuel gas using gas chromatography (GC) technology, and shall continuously measure and record the fuel flow to the boilers and duct burners. Data substitution will be used during periods of missing data such as periods of GC maintenance or malfunction. The best available estimate of the parameter, based on all available process data may be used for substitution. Heat input to the boilers and duct burners will be calculated as follows:

$$\boldsymbol{HI_{rate-gas}} = \frac{\boldsymbol{GAS_{rate}} \times \boldsymbol{HHV_{gas}}}{\boldsymbol{10^6}}$$

Where:

$\boldsymbol{HI_{rate-gas}}$ = Heat input rate, in MMBtu
$\boldsymbol{GAS_{rate}}$ = Gas volumetric flow, in scf
$\boldsymbol{HHV_{gas}}$ = Higher heating value of refinery fuel, in Btu/scf
$\boldsymbol{10^6}$ = Conversion of Btu to MMBtu

(m) Starting with issuance of SPM No. 089-45450-00453, the permittee shall perform preventive maintenance and testing on the SCR catalyst during each planned 3SPS boiler and duct burner outage. Preventive maintenance and testing on the SCR catalyst shall be performed at least once every three years.

D.02.3 Performance Testing Requirements

(a) In order to demonstrate compliance with Conditions D.02.1, not later than 180 days after the issuance date of SPM No. 089-43173-00453, the Permittee shall perform PM and PM_{10} testing of one boiler and duct burner combination in the No. 3 Stanolind Power Station listed in the table below:

Boiler	Duct Burner	Stack
#31	#31	503-01
#32	#32	503-02
#33	#33	503-03
#34	#34	503-04
#36	#36	503-05

Utilizing methods as approved by the Commissioner, subject to the following:

(1) At least one (1) No. 3 SPS boiler and duct burner combination shall be tested at least once every twelve (12) consecutive month period from the date of the most recent valid test.

(2) Testing will be conducted for the boiler and duct burner combination for which the longest time has passed since the last test for that combination.

(3) If the lb/MMBtu emission rate of PM_{10} from of any test conducted is greater than twenty percent (20%) of the value established in the most recent test for that boiler and duct burner combination, then the Permittee shall test in accordance with the schedule under Condition D.02.3(b) (Alternative Triggered Testing Requirement).

(4) Each No. 3 SPS boiler and duct burner combination listed in the table in paragraph (a) shall be tested at least once in every five (5) year period from the date of its previous test conducted after issuance of SPM No. 089-43173-00453.

(5) Starting with issuance of SPM No. 089-45450-00453, a test shall not be considered a valid test, and the Permittee will not have met the requirement of this condition to test, unless

(i) The average total ammonia solution injection rate (in lb/hour) for the tested boiler and duct burner combination for all runs is greater than the maximum of the average monthly total ammonia injection rate from the preceding five years (in lb/hour); and

(ii) The ratio of average total ammonia solution injection rate divided by the total sulfur content in the fuel gas in lb/hr/ppm is greater than two (2).

(iii) For the purposes of calculating the average monthly total ammonia injection rate, hours where the total 3SPS heat input rate is zero shall be excluded from the average. Total ammonia injection rate during the test as well as the calculated average total ammonia injection from the preceding five-year period shall be included in the results submitted in accordance with Condition C.8(c).

(b) Alternative Triggered Testing Requirement:
If a valid test establishes a PM_{10} emission rate that is greater than the 20% of the value established in the most recent test for that boiler and duct burner combination, submission of such test results to IDEM triggers the following accelerated testing schedule for the remaining four (4) boiler and duct burner combinations.

(1) The Permittee must conduct a valid test for PM and PM_{10} on each of the other four (4) boiler and duct burner combinations no more than 2.5 years (30 months) from the date the Permittee submits the triggering test results to IDEM.

(2) Condition D.02.3(a)(1) will continue to apply to accelerated testing conducted pursuant to this subpart (b).

(3) Conditions D.02.3(a)(2) and D.02.3(a)(3) will not apply to accelerated testing conducted pursuant to this subpart (b).

(4) Upon completion of the fourth and final boiler and duct burner combination valid test conducted pursuant to this subpart (b), future tests shall be conducted in accordance with D.02.3(a).

(c) In order to demonstrate compliance with Conditions D.02.1, not later than 180 days after the issuance date of SPM No. 089-43173-00453, the Permittee shall perform PM and PM_{10} testing of the boiler in the No. 3 Stanolind Power Station selected for testing required by Condition D.02.3(a), utilizing methods as approved by the Commissioner, subject to the following:

(1) Subsequent to the initial test required by Condition D.02.3(c), at least one (1) No. 3 SPS boiler listed in the table in paragraph (a) shall be tested in conjunction with the subsequent test required by Condition D.02.3(a) until all five (5) boilers have been tested. After all five (5) boilers have been tested, each No. 3 SPS boiler listed in the table in paragraph (a) shall be tested for PM and PM_{10} at least once in every five (5) year period from the date of its previous test conducted after issuance of SPM No. 089-43173-00453.

(d) 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. PM_{10} includes filterable and condensable PM.

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

D.02.4 Fuel Gas Temperature and Pressure Monitoring

A continuous monitoring system for the 3SPS boilers and associated duct burners shall be calibrated, maintained, and operated for measuring the fuel gas temperature and pressure. For the purpose of this condition, continuous means no less often than once per fifteen (15) minutes.

D.02.5 Ammonia Injection Rate Monitoring

The Permittee shall monitor and record the ammonia injection rate on each Selective Catalytic Reduction (SCR) system continuously when the associated processes are in operation. For the purpose of this condition, continuous means no less often than once per fifteen (15) minutes.

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

D.02.6 Record Keeping Requirements

(a) In order to document the compliance status with Condition D.02.1, the Permittee shall maintain records of the monthly and twelve (12) consecutive month of PM and PM_{10} from the following units. Records shall be complete and sufficient to establish compliance with the limits in Condition D.02.1.

TGU A and TGU B
FCU 500
FCU 600
3SPS Boiler SCR on stacks 503-01, 503-02, 503-03, 503-04, and 503-05
3SPS Duct Burners on stacks 503-01, 503-02, 503-03, 503-04, and 503-05

(b) In order to document the compliance status with Condition D.02.1, the Permittee shall maintain records of:

(1) Monthly hours of operation for TGU A and TGU B;
(2) Hourly and monthly average heat input rate of refinery fuel gas combusted by the No. 3 SPS boilers and duct burners; and
(3) Monthly values of A, S, B, and CSF determined in accordance with D.02.2(i)(1).
(4) Preventive maintenance and testing records for the SCR catalyst during each planned 3SPS boiler and duct burner outage.

(b) To document the compliance status with Condition D.02.4, the Permittee shall maintain continuous fuel gas temperature and pressure records for the boilers and duct burners.

(c) In order to document the compliance status with Condition D.02.3(a)(5) and D.02.5, the Permittee shall maintain continuous records of the ammonia injection rate.

(d) Condition D.21.17(e) contains the requirement for the Permittee to maintain a record of the monthly amount of coke burned in FCU 500.

(e) Condition D.22.17(e) contains the requirement for the Permittee to maintain a record of the monthly amount of coke burned in FCU 600.

(f) Condition D.24.14(c) contains the requirement for the Permittee to maintain a record of the monthly firing rate the No. 3 SPS boilers and duct burners.

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

D.02.7 Reporting Requirements

(a) In order to document the compliance status with Condition D.02.1, the Permittee shall submit a quarterly summary of the following for the TGU A, TGU B, FCU 500, FCU 600, 3SPS Boiler SCRs and 3 SPS Boiler Duct Burners not later than thirty (30) days after the end of the quarter being reported:

(1) Combined twelve (12) consecutive month PM emissions, PM_{An}, as defined at Condition D.02.2(e) for each month of the quarter.

(2) Combined twelve (12) consecutive month PM_{10} emissions, $PM_{10\ An}$, as defined at Condition D.02.2(j) for each month of the quarter.

(3) Monthly values of A, S, B, and CSF determined in accordance with D.02.2(i)(1) for each month of the quarter.

(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.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 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* (11A)	250	120-01	Ultra Low NO_X Burners
H-2 (11A)	45	120-02	None
H-3 (11A)	55	120-03	None
H-200* (11C)	249.5	120-05	Ultra Low NO_X Burners
H-300 (11C)	180	120-06	Ultra-Low NOx Burners

* 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.

A Brine Conditioning System (BCS), added as part of the WEP, including the following units:

(9) T-400 Brine Stripper Tower, approved in 2017 for construction.

(10) D-400 Stripper Overhead Receiver, approved in 2017 for construction.

(11) D-401 Liquid Ring Separator, approved in 2017 for construction.

(12) D-402 Second Stage Liquid Ring Separator Drum, approved in 2018 for construction.

(13) D-403 Oil Skimming Drum, approved in 2018 for construction.

(14) 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.

(15) Leaks from process equipment, including pumps, compressors (K-400A, K-400B and K-400C), pressure relief devices, sampling connection systems, open-ended lines and valves, and heat exchange and instrumentation systems, approved in 2017 for construction, and compressors K-401A and K-401B, approved for construction in 2018.

(The information describing the process contained in this emissions unit 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 NOx and SO_2 emissions limits:

Unit ID	NOx Emissions (tons per 12 consecutive month period)	SO_2 emissions (tons per 12 consecutive month period)
H-1X H-2 H-3	80.7 (combined)	12.4 (combined)
H-200 H-300	127.0 (combined)	15.9 (combined)

(2) Firing rate limit, CO, VOC, PM and PM_{10} emissions limits:

Heater ID	Firing rate (10^3 mmBTU) per 12 consecutive month period	CO (lb/mmBTU)	VOC (lb/mmBTU)	PM (lb/mmBTU)	PM_{10} (lb/mmBTU)
H-1X	2,237.30 (combined)	0.082	0.0054	0.0075	0.0075
H-2		0.082	0.0054	0.0075	0.0075
H-3		0.082	0.0054	0.0075	0.0075
H-200	2,871.53 (combined)	0.082	0.0054	0.0075	0.0075
H-300		0.082	0.0054	0.0075	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

Process Heater	SO_2 Limit (lbs/mmBTU)	SO_2 Limit (lbs/hour)
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 [326 IAC 2-7-5(1)]

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 in Condition D.1.8(b) for 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)).

(c) In order to assure compliance with the NOx limit in Condition D.1.2(b)(1), NOx emissions shall be determined each month by adding the total emissions for that month to the total emissions for the preceding eleven (11) months. Total emissions for each month shall be calculated using the following equations:

(1) Combined Pipe Still 11A heaters:

E_{11A} (ton/month) = [(H-1X (NO_X CEMS) * FR_{H-1X}) + (H-2 NOx * FR_{H-2}) + (H-3 NOx * FR_{H-3})] * 1 ton/2000 lbs.		
Where:		
E_{11A} (ton/month)	=	Combined NOx emissions from H-1X, H-2 and H-3 in tons per month
H-1X (NO_X CEMS)	=	NOx lb/mmBtu for H-1X calculated per 40 CFR Part 60, Appendix A, Method 19, using the average concentration as measured by the CEMS over the preceding month.
FR_{H-1X}		Firing rate in mmBTU to H-1X from all fuels fired in H-1X over the previous month period.
H-2 NOx	=	0.098 lb NOx/mmBTU or the NOx lb/mmBTU determined by the most recent stack test
FR_{H-2}	=	Firing rate in mmBTU to H-2 from all fuels fired in H-2 over the previous month period.
H-3 NOx	=	0.098 lb NOx /mmBTU or the NOx lb/mmBTU determined by the most recent stack test
FR_{H-3}	=	Firing rate in mmBTU to H-3 from all fuels fired in H-3 over the previous month period.

(2) Combined Pipe Still 11C heaters:

E_{11C} (ton/month) = [(H-200 (NO_X CEMS) * FR_{H-200}) + (H-300 NOx * FR_{H-300})] * 1 ton/2000 lbs].		
Where:		
E_{11C} (ton/month)	=	Combined NOx emissions from H-200 and H-300 in tons per month
H-200 (NO_X CEMS)	=	NOx lb/mmBtu for H-200 calculated per 40 CFR Part 60, Appendix A, Method 19, using the average concentration as measured by the CEMS over the preceding month.
FR_{H-200}	=	Firing rate in mmBTU to H-200 from all fuels fired in H-200 over the previous month period
H-300 NOx	=	Prior to the startup of ultra-low NOx burners, 0.137 lb NOx/mmBTU or the NOx lb/mmBTU determined by the most recent stack test

	=	After the startup of ultra-low NOx burners, 0.05 lb NOx/MMBtu or the NOx lb/MMBtu determined by the most recent stack test conducted in accordance with paragraph D.1.10(a)(2)
FR_{H-300}	=	Firing rate in mmBTU to H-300 from all fuels fired in H-300 over the previous month period

D.1.10 Performance Testing Requirements

(a) (1) 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 paragraph D.1.2(b)(1), the Permittee shall conduct performance tests to measure emissions of NO_X from Heater H-300 once every five (5) years.

(2) Pursuant to MSM No. 089-44288-00453, within 60 days after achieving the maximum production rate at which the unit will be operated but not later than 180 days after startup of Heater H-300 using ultra-low NOx burners, in order to demonstrate compliance with the emission limits in paragraph D.1.2(b)(1), the Permittee shall conduct performance tests to measure emissions of NO_X from Heater H-300.

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) To document the compliance status with Conditions D.1.2(b)(1), D.1.2(b)(2) and D.1.8(b), the Permittee shall maintain records in accordance with (1) through (7) below. Records maintained for (1) through (7) shall be taken monthly and shall be complete and sufficient to establish compliance with the limits established in Condition D.1.2.

(1) Combined monthly firing rates for heaters H-1X, H-2, H-3,
(2) Combined monthly firing rates for heaters H-200 and H-300.
(3) NOx emissions, as measured by the CEMS, for heater H-1X.
(4) Combined NOx emissions for heaters H-1X, H-2 and H-3.
(5) Combined NOx emissions for heaters H-200 and H-300
(6) Combined SO2 emissions for heaters H-1X, H-2 and H-3.
(7) Combined SO2 emissions for heaters 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 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 following:

(1) Combined monthly firing rates for heaters H-1X, H-2, H-3,
(2) Combined monthly firing rates for heaters H-200 and H-300;
(3) Combined NOx emissions for heaters H-1X, H-2, and H-3;
(4) Combined NOx emissions for heaters H-200 and H-300;
(5) Combined SO_2 emissions for heaters H-1X, H-2, and H-3; and
(6) Combined SO_2 emissions for heaters H-200 and H-300.

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 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).The No. 11B Coker and existing Coke Handling System, heaters H-101, H-102, H-103, and H-104 were permanently shut down as of May 10, 2014.

(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. As part of the WEP, there is a replacement of tubes and outlet piping on the existing heaters with an upgraded metallurgy to reduce fouling. There will also be enhancements made to the Coke Handling System (installation of new rail track and crane automation improvements). Also, there are new piping connections (valves and flanges). 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 feed at a vapor pressure less than 0.5 psia. Tank TK-6254 is equipped with a fixed roof, nitrogen blanketed, and vented to a caustic scrubber and carbon canister control system in series (Option 1 Controls) or vented to a vapor recovery system (Option 2 Controls). The vapor recovery system routes the vapors from TK-6254 to the flare gas recovery system (FGRS) at the South Flare (FGRS1).

(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).

(H) Storage vessels containing coker feed with a maximum true vapor pressure, as defined at 326 IAC 8-9-6(i)(4)(A), less than 0.5 psia, as follows:

(1) One (1) fixed roof storage vessel, identified as TK-6126, constructed in 1999, approved in 2021 for modification, with a maximum storage capacity of 3,108,000 gallons (11,764 m^3), venting to a vapor recovery system (Option 2 Controls).

(2) One (1) fixed roof storage vessel, identified as TK-6127, constructed in 2000, approved in 2021 for modification, with a maximum storage

capacity of 3,108,000 gallons (11,764 m^3), venting to a vapor recovery system (Option 2 Controls).

(The information describing the process contained in this emissions unit 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) RESERVED

(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 originating in 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 combined emissions of SO_2 from heaters F-201, F-202 and F-203 shall not exceed 30.3 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 combined emissions of CO from heaters F-201, F-202 and F-203 shall not exceed 51.9 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	5,466.3 (combined)
F-202	
F-203	

(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, modified by SPM 089-42998-00453, and as originating in the Consent Decree entered in Civil No. 2:12-CV-00207, emissions of H_2S from 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 Option 1 or Option 2 controls are offline for maintenance shall be included in determining compliance with this emission limit.

(m) Pursuant to SSM 089-32033-00453 and as originating in the Consent Decree entered in Civil No. 2:12-CV-00207, emissions of VOC from 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 RESERVED

D.2.4 Volatile Organic Liquid Storage Vessels [326 IAC 8-9-6]

Pursuant to 326 IAC 8-9-6(b), for storage tanks TK-6254, TK-6126, and TK-6127 which are used to store liquids with a maximum true vapor pressure, determined in accordance with 326 IAC 8-9-6(i)(4), 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 originating in 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 Coker 2 and Coke Handling System:

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) RESERVED

(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 originating in 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 originating in 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 originating in 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 originating in 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 originating in 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 originating in 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 originating in 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, modified by SPM 089-42998-00453, and as originating in the Consent Decree entered in Civil No. 2:12-CV-00207 as amended, the existing Coker Feed Tank (TK-6254) shall be equipped with a fixed roof, shall be nitrogen blanketed and shall be vented to a caustic scrubber and carbon canister control system in series (Option 1 Controls). As an alternative to Option 1 Controls, by no later than October 1, 2021, the existing Coker Feed Tank (TK-6254) and two (2) additional Coker Feed Tanks (TK-6126 and TK-6127) shall all be vented to a vapor recovery system that routes the vapors from the three (3) tanks (TK-6254, TK-6126, and TK-6127) to the refinery's flare gas recovery system (FRGS) at the South Flare (FRGS1) (Option 2 Controls). If the Permittee elects to comply by using Option 2 Controls, by no later than October 1, 2021, the Permittee shall install a new compressor at FRGS1. The FRGS1 shall comply with the requirements in paragraph D.35.8.D. Electing to comply by using a vapor recovery system (Option 2 Controls) does not preclude the Permittee from electing to return to a caustic scrubber and carbon canister in series control system for TK-6254 (Option 1 Controls). Coker Feed Tank TK-6254 shall be controlled at all times except during periods when the caustic scrubber and carbon canister control system in series (Option 1 Controls) or the vapor recovery system (Option 2 Controls) is offline for maintenance or a malfunction event.

(i) Pursuant to SSM 089-32033-00453 and as originating in 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 originating in 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.

(k) Pursuant to SSM 089-42988-00453 and as originating in the Consent Decree entered in Civil No. 2:12-CV-00207, if the Permittee elected to comply with Option 2 Controls, the Permittee shall install the following equipment:

(1) GE Panametric Ultrasonic Dual Pass analyzers or equivalent analyzers that comply with the following accuracy requirements (Analyzers): a flow sensor with a measurement sensitivity of no more than five (5) percent of the flow rate or ten (10) cubic feet per minute, whichever is greater. These Analyzers shall be installed on the line going to FRGS1, which consists of the vapor flow from the three (3) coker feed tanks (TK-6254, TK-6126, and TK-6127).

(2) A flow meter that measures the amount of natural gas added at the natural gas ejector.

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

D.2.10 Operating Requirements

(a) Pursuant to SSM 089-32033-00453 and as originating in 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 originating in 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) RESERVED

(b) Pursuant to SSM 089-32033-00453 and as originating in 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, modified by SPM 089-42998-00453, and as originating in the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to demonstrate compliance with condition D. 2.2.(l), for Option 1 Controls, the Permittee shall monitor the daily average H_2S concentration at the outlet of the carbon canister control system for 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) Coker feed tank VOC monitoring

(1) Pursuant to SSM 089-32033-00453, modified by SPM 089-42998-00453, and as originating in 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, for Option 1 Controls, the Permittee shall monitor the VOC concentration at the outlet of the carbon canister system in accordance with the methods used to comply with the requirements for breakthrough monitoring for carbon canisters in Paragraph 52.a.ii and 52.b.ii of the Consent Decree entered in Civil No. 2:12-CV-00207 and shall record the results of such monitoring. The Permittee shall verify and record that flow is present when the VOC concentration is measured at the tank vent and determine the monthly average vapor flow based on the nitrogen purge rate to TK-6254 and use the VOC concentration and nitrogen purge flow to calculate the VOC emissions rate.

(2) Pursuant to SSM 089-42988-00453 and as originating in the Consent Decree entered in Civil No. 2:12-CV-00207, and in order to demonstrate compliance with condition D.2.2.(m), for Option 2 Controls, annually, the Permittee shall use an Optical Gas Imaging Camera to video image and record emissions from the tank roof and related vent systems on the coker feed tanks, TK-6254, TK-6126, and TK-6127. If imaging indicates emissions inconsistent with well-maintained floating roof tanks, seals, fittings, or welds, the Permittee shall inspect and, if necessary, repair the leaks consistent with the underlying Federal, State or local regulations applicable to the tank(s). The Permittee will report the results of these inspections and any corrective actions required during the next semi-annual Part VIII report.

D.2.12 Performance Testing

(a) 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.

(b) Pursuant to SSM 089-42988-00453 and as originating in the Consent Decree entered in Civil No. 2:12-CV-00207, within 180 days of startup of Option 2 Controls for Tanks TK-6254, TK-6126, and TK-6127, the Permittee shall conduct continuous emissions monitoring of VOCs, Total Reduced Sulfur (TRS), and H_2S for a period of no less than 30 consecutive days. If the Permittee is required to evacuate the area of the three (3) tanks (TK-6254, TK-6126, and TK-6127) for safety reasons during the 30 day testing period, the Permittee shall not be required to restart the 30-day period of testing, but shall extend the number of days of testing by the number of days the area was evacuated, for a total of at least 30 days.

(1) Testing shall be conducted after the natural gas ejector, but before gases from the three (3) tanks (TK-6254, TK-6126, and TK-6127) mix with other streams, and prior to the flare gas recovery system. Testing shall be conducted as follows:

(A) Utilizing process analyzers for VOC, TRS, and H_2S and following the manufacturer's specifications for operation and calibration; or

(B) Utilizing a mass spectrometer for VOCs, TRS, and H_2S and following the manufacturer's specifications for operation and calibration; or

(C) Utilizing Test Methods 25/25A and 18 or Method 320 for VOCs and Method 15 or 16 for TRS and H_2S.

(2) The Permittee shall conduct optical gas imaging (OGI) on each of the three (3) tank's (TK-6254, TK-6126, and TK-6127) deck fittings, including, but not limited to, vacuum breakers, manways, and pressure relief devices, for a minimum of 15 consecutive minutes per tank during this 30-day period. The OGI video shall be submitted as part of the test results.

(3) The Permittee shall record the hourly average tank levels and the hourly average bulk liquid temperature for each of the three (3) tanks (TK-6254, TK-6126, and TK-6127), for a period of 30 days prior to commencement of testing, and for the 30 days of continuous emissions testing of the three (3) tanks, for a total period of at least 60 consecutive days (30 days before testing and 30 days during testing).

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 originating in 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 SSM 089-42988-00453 and as originating in the Consent Decree entered in Civil No. 2:12-CV-00207, after startup of the vapor recovery system (Option 2 Controls), the Permittee shall record flow data for a period of at least one year, including: natural gas in and vent flow to FGRS1; and pressure in the header between the ejector and the three (3) tanks (TK-6254, TK-6126, and TK-6127) Option 2 Controls.

(b) RESERVED

(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 tanks TK-6254, TK-6126, and TK-6127 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 combined monthly firing rates, combined CO emissions, and combined SO_2 emissions for heaters F-201, F-202, and F-203 and NOx 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, modified by SPM 089-42998-00453, and as originating in the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to document compliance with Condition D.2.2(l), for Option 1 Controls, the Permittee shall maintain records of daily average H_2S concentration at the outlet of the carbon canister control system and the daily average vapor flow based on the nitrogen purge rate to TK-6254.

(l) Pursuant to SSM 089-32033-00453, modified by SPM 089-42998-00453, and as originating in the Consent Decree entered in Civil No. 2:12-CV-00207 and in order to document compliance with Condition D.2.2(m), for Option 1 Controls, the Permittee shall maintain records of the monthly measurement of the VOC concentration at the outlet of the carbon canister control system and record whether flow is present when the VOC concentration is measured at the tank vent.

(m) Section C - General Record Keeping Requirements 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) Coker feed tank vapor controls

(1) Pursuant to SSM 089-42988-00453 and as originating in the Consent Decree entered in Civil No. 2:12-CV-00207, if the Permittee chooses to comply with Option 2 Controls, the Permittee shall send a letter to EPA and IDEM notifying them that the Permittee is selecting Option 2 pursuant to the Consent Decree entered in Civil No. 2:12-CV-00207 no later than 30 days after initial startup of the Option 2 Controls. The Permittee is not precluded from electing to return to Option 1 Controls (or back to Option 2 Controls after utilizing Option 1 Controls), provided that EPA and IDEM are notified of that election no later than fifteen (15) days after the Permittee has made the change.

(2) Pursuant to SSM 089-42988-00453 and as originating in the Consent Decree entered in Civil No. 2:12-CV-00207, for Option 2 Controls, following the start-up of the three (3) coker feed tanks' (TK-6254, TK-6126, or TK-6127) Option 2 Controls, the Permittee shall submit semi-annual reports of flow data for a period of at least one year, including: natural gas in and vent flow to FGRS1; and pressure in the header between the ejector and the three (3) tanks' (TK-6254, TK-6126, and TK-6127) Option 2 Controls.

(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 combined monthly firing rates, combined CO emissions, NOx emissions for heaters F-201, F-202, and F-203, and combined SO_2 emissions for 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. As part of the WEP, there will be new control valves, instrumentation upgrades (valves, flanges) and new piping connections (valves, flanges). 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
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.
**Heaters H-1AN, H-1AS, H-1B, H-2, H-1CN, H-1CX were permanently shut down as of November 30, 2012.

(2) RESERVED

(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).

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

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

D.3.1 RESERVED

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 RESERVED

D.3.4 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 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) RESERVED

(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	86.5 (combined)	0.0054	0.0075
H-101B		0.0054	0.0075
H-102		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	9,119.2 (combined)
H-101B	
H-102	

(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	50.4 (combined)
H-101B	
H-102	

(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 RESERVED

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. Heaters H-1AN, H-1AS, H-1B, H-2, H-1CN, and H-1CX were permanently shut down as of November 30, 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 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 [326 IAC 2-7-5(1)]

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) RESERVED

(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 combined monthly firing rates, combined CO emissions, combined SO_2 emissions for heaters H-101A, H-101B, and H-102, and NO_X emissions for 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 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 combined monthly firing rates, combined CO emissions, and combined SO_2 emissions for heaters H-101A, H-101B, and H-102 and NOx 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) RESERVED

(3) RESERVED

(4) RESERVED

(5) RESERVED

(6) RESERVED

(7) RESERVED

(8) RESERVED

(9) RESERVED

(10) RESERVED

(11) RESERVED

(12) One (1) modular degassing unit, which removes gases that are emitted during the cooling of molten sulfur. Removed gases are vented to the front end of Claus Trains D and/or E.

(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) The sealed sulfur collection 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).

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 each of the two (2) offgas treaters/thermal oxidizers identified as TGU A and TGU B shall not exceed 0.03 grains per dry standard cubic foot.

D.4.2 RESERVED

D.4.3 Lake County Sulfur Dioxide (SO_2) Emission Limitations [326 IAC 7-4.1-3]

(a) RESERVED

(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) RESERVED

(2) RESERVED

(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) RESERVED

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) RESERVED

(2) RESERVED

(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 SO2 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) RESERVED

(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) 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) RESERVED

(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, and CO 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, and CO 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 Performance for Petroleum Refineries [326 IAC 12] [40 CFR 60, Subpart Ja]

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 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) RESERVED

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 RESERVED

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

(a) Pursuant to SSM 089-32033-00453 and as specified 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 specified 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 specified 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) RESERVED

(e) RESERVED

(f) Pursuant to SSM 089-32033-00453 and as specified 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. Pit 2400 was shut down prior to May 10, 2014.

(g) RESERVED

(h) Pursuant to SSM 089-32033-00453 and as specified 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) RESERVED

(j) Pursuant to SSM 089-32033-00453 and as specified 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 [326 IAC 2-7-5(1)]

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) RESERVED

(d) RESERVED

D.4.10 Compliance Determination Requirements

(a) RESERVED

(b) Pursuant to SSM 089-32033-00453 and as specified 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	=	TGU SO_2 Emissions in tons per month
F	=	Measured total TGU incinerator stack flow rate, dscf at standard conditions (60º F), for the month
C	=	Average concentration of SO_2 in TGU 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) The NOx continuous emission monitoring systems (CEMS) on TGU A 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) The NOx continuous emission monitoring systems (CEMS) on TGU B 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) RESERVED

(b) RESERVED

(c) RESERVED

(d) RESERVED

(e) RESERVED

(f) RESERVED

(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) 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 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) RESERVED

(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) RESERVED

(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) 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. As part of WEP, there will be rerouting of naphtha streams (valves and flanges), removal of hydraulic constraints (pump modifications), and new piping connections (valves and flanges).

(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 [326 IAC 2-7-5(1)]

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 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) (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.

The following sources have been added as part of the WEP:

(C) RESERVED

(D) As part of WEP, there will be rerouting of naphtha streams (valves and flanges), removal of hydraulic constraints (pump modifications), replacement of trays in distillation towers, upgrades to heat exchangers, and new piping connections (valves and flanges).

(2) Vapor Recovery Unit VRU 400 for the Coker 2, permitted in 2008, to be installed as part of the WRMP project, approved in 2016 for modification. 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. As part of the WEP, there are tray modifications in distillation towers and new piping connections (valves and flanges). 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 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.

(6) As part of the WEP there are removal of hydraulic constraints (pump modifications), installation of a cooler, and new piping connections (valves, flanges).

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

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

D.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 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).

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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. As part of the WEP, there are modifications to trays and new nozzles for the distillation towers, and new piping connections (valves and flanges). 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 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.

As part of the WEP, there are modifications to the C-250 feed drum, removal of hydraulic constraints (pump modifications), installation of a filter coalescer, and the installation of new piping connections (valves and flanges).

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

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

D.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 specified 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 specified 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 specified 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 [326 IAC 2-7-5(1)]

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 specified 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 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 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.

(The information describing the process contained in this emissions unit 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	1861.5 (combined)	10.2 (combined)
F-200B		

(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 specified 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 specified 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 specified 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 [326 IAC 2-7-5(1)]

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 specified 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 combined monthly firing rates and combined 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 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 combined monthly firing rates and combined 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. As part of the WEP, there are removal of hydraulic constraints (pump modification) and new piping connections (valves and flanges). 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 specified 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 specified 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 specified 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 specified 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 specified 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 [326 IAC 2-7-5(1)]

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 specified 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 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:

(I) 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) RESERVED

(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 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 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 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.

(7) As part of the WEP, there are new fugitive components (valves, flanges and pumps).

(The information describing the process contained in this emissions unit 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	

Process Heater Identification	SO_2 Limit (lbs/mmBTU)	SO_2 Limit (lbs/hour)
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	Firing rate (10^3 mmBTU) per 12 month period	CO (lb/mmBTU)	VOC (lb/mmBTU)	PM (lb/mmBTU)	PM_{10} (lb/mmBTU)
F-1	8,340.59 (combined)	0.082	0.0054	0.0075	0.0075
F-2		0.082	0.0054	0.0075	0.0075
F-3		0.082	0.0054	0.0075	0.0075
F-4		0.082	0.0054	0.0075	0.0075
F-5		0.082	0.0054	0.0075	0.0075
F-6		0.082	0.0054	0.0075	0.0075
F-7		0.082	0.0054	0.0075	0.0075
F-8A		0.082	0.0054	0.0075	0.0075
F-8B		0.082	0.0054	0.0075	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	NOx (tons per 12 consecutive month period)	SO_2 (tons per 12 consecutive month period)
F-1	566.1 (combined)	46.0 (combined)
F-8A		
F-8B		
F-2		
F-3		
F-4		
F-5		
F-6		
F-7		

(c) Pursuant to SSM 089-32033-00453, and as specified 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 [326 IAC 2-7-5(1)]

D.16.8 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.16.2 shall be determined based on the daily average sulfur dioxide emission rate, in pounds per hour.

(b) In order to assure compliance with the NOx limit in Condition D.16.3, NOx emissions shall be determined each month by adding the total emissions for that month to the total emissions for the preceding eleven (11) months. Total emissions for each month shall be calculated using the following equation:

E_{4UF} (ton/month) = {(F-2 (NO_X CEMS) * FR_{F-2}) + (F-3 (NOx CEMS) * FR_{F-3}) + [(F-1/F-8A/F-8B NOx) * (FR_{F-1} + FR_{F-8A} + FR_{F-8B})] + [(F-4/F-5/F-6 NOx) * (FR_{F-4} + FR_{F-5} + FR_{F-6})] + (F-7 NOx * FR_{F-7})} * 1 ton/2000 lbs.

Where:

E_{4UF} (ton/month)	=	Combined NOx emissions from F-1, F-2, F-3, F-4, F-5, F-6, F-7, F-8A, and F-8B in tons per month
F-2 (NO_X CEMS)	=	NOx lb/mmBTU calculated per 40 CFR Part 60, Appendix A, Method 19, using the average concentration as measured by the CEMS over the previous month period.
FR_{F-2}	=	Firing rate in mmBTU to F-2 from all fuels fired in F-2 over the previous month period.
F-3 (NO_X CEMS)	=	NOx lb/mmBTU calculated per 40 CFR Part 60, Appendix A, Method 19, using the average concentration as measured by the CEMS over the previous month period.
FR_{F-3}	=	Firing rate in mmBTU to F-3 from all fuels fired in F-3 over the previous month period.
F-1/F-8A/F-8B NOx	=	0.244 lb NOx/mmBTU or the NOx lb/mmBTU value from the most recent stack test
FR_{F-1}	=	Firing rate in mmBTU to F-1 from all fuels fired in F-1 over the previous month period.

FR_{F-8A}	=	Firing rate in mmBTU to F-8A from all fuels fired in F-8A over the previous month period.
FR_{F-8B}	=	Firing rate in mmBTU to F-8B from all fuels fired in F-8B over the previous month period.
F-4/F-5/F-6 NOx	=	0.183 lb NOx/mmBTU or the NOx lb/mmBTU value from the most recent stack test
FR_{F-4}	=	Firing rate in mmBTU to F-4 from all fuels fired in F-4 over the previous month period.
FR_{F-5}	=	Firing rate in mmBTU to F-5 from all fuels fired in F-5 over the previous month period.
FR_{F-6}	=	Firing rate in mmBTU to F-6 from all fuels fired in F-6 over the previous month period.
F-7 NOx	=	0.098 lb NOx /mmBTU or the NOx lb/mmBTU value from the most recent stack test
FR_{F-7}	=	Firing rate in mmBTU to F-7 from all fuels fired in F-7 over the previous month period.

*F-1/F-8A/F-8B NOx and F-4/F-5/F-6 NOx are established on a weighted average emission rate based on maximum heater fired duty (mmBtu/hr).

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.

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 combined monthly firing rates and combined SO_2 emissions and combined NOx 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 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 combined monthly firing rates, combined SO_2 emissions and combined NOx 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 [326 IAC 2-7-5(1)]

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 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 [326 IAC 2-7-5(1)]

D.18.9 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.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 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 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.

(The information describing the process contained in this emissions unit 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	VOC (lb/mmBTU)	PM_{10} (lb/mmBTU)
F-801A	0.0054	0.0075
F-801B	0.0054	0.0075
F-801C	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	PM (lb/mmBTU)
F-801A	0.0075
F-801B	0.0075
F-801C	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.19.5. An instrument reading of 2000 parts per million (ppm) or greater shall constitute a leak for pumps in heavy liquid service.

Additional limits on firing rate, SO_2, NOx, and CO for the CFHU heaters (F-801A, F-801B, and F-801C) are in Section D.01.

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.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 [326 IAC 2-7-5(1)]

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 and to demonstrate compliance with Conditions D.01.1 and D.19.3, 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) 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 Conditions D.01.1, D.19.2, and D.19.8 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) RESERVED

(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 contains the Permittee's obligations with regard to the records required by paragraphs (a), (b), (d), 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 Condition D.19.2, 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.01.1 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) RESERVED

(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), and (d) 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 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).

<u>Main Operating Scenario:</u>
The CRU operates as a naphtha hydrotreater. Maximum production under this scenario is 27,000 barrels per day.

<u>Alternative Operating Scenario:</u>
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 emissions unit 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

Process Heater	PM_{10} Limit (lbs/mmBTU)	PM_{10} Limit (lbs/hour)
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 [326 IAC 2-7-5(1)]

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 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) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, on and after December 31, 2013, 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.

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 [326 IAC 2-7-5(1)]

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:

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 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 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.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:

$R_{c(month)}$ (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 500 to demonstrate compliance with Condition D.21.3(b) 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 Condition D.21.3(b), 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.21.3(b), 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.21.3(b), 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 established in the most recent performance test conducted pursuant to 40 CFR §60.104a.	An excursion is defined as a daily average exhaust coke burn-off rate exceeding the level established during the during the most recent performance test conducted pursuant to 40 CFR §60.104a.	An excursion is defined as not following the inspection schedule and procedures specified in the Continuous Compliance Plan (CCP).
III. Performance Criteria	--	--	--
A. Data Representativeness	Continuous Parameter	Continuous Parameter	Recording, inspection, and maintenance

Monitoring Approach for PM_{10} and PM_{Total} Emissions From FCU 500			
Parameter	**Indicator No. 1**	**Indicator No. 2**	**Indicator No. 3**
	Monitoring System (CPMS) requirements in 40 CFR 60.105a(b)(1)(i) and (iii).	Monitoring System (CPMS) requirements in 40 CFR 60.105a(b)(1)(iii) and (iv).	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 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°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) Pursuant to SSM 089-32033-00453 and as required by the Consent Decree in Civil No. 2:12-CV-00207, on and after December 31, 2013, 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_{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_{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.

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

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.22.3(b) 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 Condition D.22.3(b), 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.22.3(b), 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.22.3(b), 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	An excursion is defined as a daily average exhaust coke burn-off rate exceeding the level	An excursion is defined as not following the inspection schedule and procedures specified in

Monitoring Approach for PM_{10} and PM_{Total} Emissions From FCU 600			
Parameter	**Indicator No. 1**	**Indicator No. 2**	**Indicator No. 3**
	falling below the level established in the most recent performance test conducted pursuant to 40 CFR §60.104a.	established during the during the most recent performance test conducted pursuant to 40 CFR §60.104a.	the Continuous Compliance Plan (CCP).
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 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

The No. 1 SPS Boilers 5, 6, and 7 were shut down as of April 1, 2010 as specified in Consent Decree 2:96CV 095RL.

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

(The information describing the process contained in this emissions unit 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) Five (5) Boilers, each approved in 2008 for modification as a contemporary project to the WRMP project, each equipped with conventional burners, a Selective Catalytic Reduction (SCR) system, and a direct-fired Duct Burner. Each direct-fired Duct Burner rated at 41 mmBTU/hr, equipped with low-Nox burners, and controlled by the Selective Catalytic Reduction (SCR) system. Each stack equipped with continuous emissions monitors (CEMS) for NOx and CO:

Boiler and Duct Burner Identification	Maximum Heat Input Capacity (mmBTU/hr)	Installation Date	Modification Date	Emissions Control	Stack Exhausted To
#31 Boiler	575	1948	2010	SCR	503-01 (NOx & CO CEMS)
#31 Duct Burner	41	2010	--		
#32 Boiler	575	1948	2010	SCR	503-02 (NOx & CO CEMS)
#32 Duct Burner	41	2010	--		
#33 Boiler	575	1951	2010	SCR	503-03 (NOx & CO CEMS)
#33 Duct Burner	41	2010	--		
#34 Boiler	575	1951	2010	SCR	503-04 (NOx & CO CEMS)
# 34 Duct Burner	41	2010	--		
#36 Boiler	575	1953	2011	SCR	503-05 (NOx & CO CEMS)
#36 Duct Burner	41	2011	--		

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

Insignificant Activities:

(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)]

(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).

(The information describing the process contained in this emissions unit 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 Particulate Matter Limitations for Lake County [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 0.03 gr/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.

These emission limits are specific to the boilers and do not apply to the duct burners.

D.24.4 Prevention of Significant Deterioration [326 IAC 2-2] and Emission Offset [326 IAC 2-3] Minor Limits

In order to render 326 IAC 2-2 and 326 IAC 2-3 not applicable, the Permittee shall comply with the following for No. 3 Stanolind Power Station Boiler #31 and Duct Burner #31, Boiler #32 and Duct Burner #32, Boiler #33 and Duct Burner #33, Boiler #34 and Duct Burner #34, and Boiler #36 and Duct Burner #36, as measured at Stacks 503-01, 503-02, 503-03, 503-04, and 503-05:

(a) Pursuant to SSM 089-25484-00453, as modified by SPM 089-36656-00453, issued on June 14, 2016, the Permittee shall comply with the following:

(1) The emissions of VOC 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 twelve (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 twelve (12) consecutive month period, with compliance determined at the end of each month.

(4) The total emissions of CO shall not exceed 260.4 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(5) The total emissions of NOx shall not exceed 260.4 tons per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) RESERVED

(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, and CO 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, and CO 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, and 36.

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 [326 IAC 2-7-5(1)]

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(a)(5) 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 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 Flotation (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 emissions unit 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 [326 IAC 2-7-5(1)]

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:

(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° 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 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 Flotation (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 Flotation (DNF) System, installed as a part of the Lakefront Upgrades Project; and Dissolved Air Flotation (DAF) Secondary Boxes, which vent to a biofilter and carbon canisters; Tank 562 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 Flotation (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 Flotation (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 Flotation (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 [326 IAC 2-7-5(1)]

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 Flotation (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 Flotation (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 Flotation (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 Flotation (DNF) System, the Permittee shall sample and determine the molecular weight of the vent exhaust from the dual carbon canisters controlling the Dissolved Nitrogen Flotation (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 Flotation (DNF) System.

(5) The VOC emissions from the Dissolved Nitrogen Flotation (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 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 also include insignificant activities listed in Section A.4 of this permit:

(1) RESERVED

(2) RESERVED

(3) External floating roof storage tanks storing petroleum hydrocarbon with vapor pressure less than 11.1 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-three (63) internal floating roof storage tanks, storing petroleum hydrocarbon with true 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	1924/2018[1]	3,380,000
3484	1996/2021[2]	3,382,264 3,380,000 after replacement
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	4,061,000
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	3,380,000
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	3,380,000
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

Notes:
1. *These units are to be replaced with like units and were approved in 2018 for construction. The exact construction years will be added after construction is complete.*
2. *TK-3484 was approved in 2021 for reconstruction. The actual date that reconstruction commences will be added as a change in the descriptive information upon completion of the reconstruction.*

(5) Miscellaneous Storage tanks including the following:

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Tank ID	Location	Description	Tank Construction Dates	Tank Capacity (gallons)	True Vapor Pressure of Liquid (psia)
D-424	4ULTRAFORMER	Methanol Tank	--[1]	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 or biodiesel	1992/2021[2]	3,876,768	<0.5
TK-3496	SO. TK FLD.	Distillate	1992	3,876,768	<0.5
TK-3498R	SO. TK FLD.	Amoco Premier Diesel [Future Lsfo]	Approved in 2016 for Construction	4,229,840	<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.	Petroleum Distillate	1948/2018[3]	3,380,000	<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	5,527,375	<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-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.	Petroleum Distillate	1945/2018[3]	3,356, 000	<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-3717R	IND. TK FLD.	Gas Oil	Approved in 2016 for Construction	4,229,840	<0.5
TK-3718	IND. TK FLD.	Gas Oil	1996	3,871,379	<0.5
TK-3719	IND. TK FLD.	Gas Oil	2015	3,357,627	<0.5
TK-3720	IND. TK FLD.	Petroleum Distillate	1946/2018[3]	3,356,000	<0.5
TK-3721	IND. TK FLD.	Gas Oil	1946	3,357,600	<0.5
TK-3721R	IND. TK FLD.	Gas Oil	Approved in 2016 for Construction	4,229,840	<0.5
TK-3722	IND. TK FLD.	Gas Oil	1952	4,227,300	<0.5

TK-3723	IND. TK FLD.	Gas Oil	2016	3,386,880	<0.5
TK-3733	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,383,520	<0.5
TK-3734	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,383,520	>0.5 and <0.75
TK-3735	IND. TK FLD.	Cru / Bou Distillate Feed	1971	3,411,072	<0.5
TK-3867	SO. TK FLD.	Stadis 450	1967	17,640	<0.5
TK-3868	SO. TK FLD.	Amogard	1953	17,640	>0.5 and <0.75
TK-3869	SO. TK FLD.	Pour Depressant	1956	23,436	<0.5
TK-3872	CRUDE STA	Used Motor Oil	1985	15,120	<0.5
TK3876	South TF	Cetane Improver	1993	14,381	<0.5
TK-3906	J&L TK FLD.	Lsfo	1956	3,381,840	>0.5 and <0.75
TK-3908	J&L TK FLD.	Amoco Premier Diesel	1956	3,381,840	<0.5
TK-3910	J&L TK FLD.	Furnace Oil [Hs]	1956	3,381,840	<0.5
TK-3913	J&L TK FLD.	Furnace Oil [Ls]	1956	3,402,977	<0.5
TK-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.	Petroleum Distillate	2020[4]	4,231,000	<0.5
TK-3506	SO. ANNEX	Petroleum Distillate	2020[4]	4,231,000	,0.5
TK-3710	IND. TK FLD.	Petroleum Distillate	2020[4]	3,385,000	<0.5
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	--	--	--
TK-3490	SO. TK FLD	Petroleum Distillate	1925	3,371,000	<0.5
3495		--	1992	3,876,768	<0.5

Notes:
1. "--" - no data provided.

2. Optional biodiesel service of this tank was approved in MSM No.089-44288-00453. The actual date that modification commences will be added as a change in the descriptive information upon completion of the modification.
3. These units are to be replaced with like units and were approved in 2018 for construction. The exact construction years will be added after construction is complete.
4. These units were approved in 2020 for construction. The entry will be revised to the actual construction date after construction commences.

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

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

(11) Fugitive components constructed as part of the construction of TK-3498R, TK-3717R, and TK-3721R, permitted in 2016.

(12) As part of the WEP, there are improvements to the Crude Tank Field, including reconfigurations of the crude field piping (valves and flanges), and new piping connections (valves and flanges).

(13) As part of WEP, there are the installation of piping connections (valves and flanges), removal of hydraulic constraints (pump modifications), heat exchanger upgrades, and new chillers.

(14) Fugitive components associated with TK-3497, TK-3506, and TK-3710, approved in 2020 for construction.

(The information describing the process contained in this emissions unit 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, 3728, 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, 3492, TK-3497, TK-3506, 3510, 3512, 3532, 3631, 3633, 3635, 3639, 3641, 3705, 3706, 3728, 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-3610, TK-3611, TK-3613, TK-3710, TK-3711, TK-3712, TK-3714, TK-3717, TK-3718, TK-3719, TK-3720, TK-3721, TK-3722, TK-3723, TK-3733, TK-3735, TK-3908, TK-3910, TK-3913, TK-3571, TK-3572, TK-3734, TK-3906, TK-3490, 3495, TK-3717R, TK-3721R and TK-3498R. Tank TK-3483 (constructed in 1924) is subject to 326 IAC 8-9, but was approved in 2018 for replacement pursuant to MSM 089-39950-00453. Upon replacement, tank TK-3483 (approved in 2018 for construction) will no longer be subject to 326 IAC 8-9.

(a) For Storage tanks 3534, 3602, 3604, 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-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-3733, TK-3735, TK-3908, TK-3910, TK-3913, TK-3571, TK-3572, TK-3734, TK-3906, TK-3490, 3495, TK-3717R, TK-3721R TK-3498R, TK-3497. TK-3506, and TK-3710 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) and D.27.10(h).

(b) For storage tanks 3633, 3635, 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).

(c) 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.

(d) 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.

(e) 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, and submit to the department 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), the Permittee shall maintain the following records for storage tanks 3633, 3635, 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.

(h) Pursuant to 326 IAC 8-9-6(h), for any tank with a capacity greater than 39,000 gallons and a maximum true vapor pressure that is normally less than seventy-five hundredths (0.75) psia, 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.

(i) 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.

(j) 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.

(k) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the records required by 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 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

(The information describing the process contained in this emissions unit 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 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 emissions unit 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 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 Marketing Terminal was permanently decommissioned pursuant to Minor Permit Modification No. 089-42328-00453.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

RESERVED

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	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.

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 emissions unit 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 2-7-5(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 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).

DRAFT

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 one (1) asphalt storage tank used to store volatile organic liquids that has a vapor pressure less than 0.75 psi:

Identification	Storage Capacity (gallons)	Year Constructed
TK-3613	8,866,200	1992

(3) The following four (4) 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
TK-3571	5,040,000	1971
TK-3572	5,040,000	1971
TK-3609*	9,652,608	1973 Modified in 2017
TK-3611	8,513,400	1973

* TK-3609 equipped with nitrogen sparging and a biofilter.

Under 40 CFR 63, Subpart CC, TK-3609 is considered as a Group 2 storage vessel that is part of the existing affected source.

Under 40 CFR 60, Subpart UU, TK-3609 is considered an affected facility.

(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	TK-3616
TK-3617	Trim Gas Oil	2007*	2,268,000	16,800,000	TK-3617
*Construction completed in 2007					

Under 40 CFR 60, Subpart UU, storage tanks TK-3614 and TK-3615 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)	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.

Insignificant Activities:

(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:

(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)(J)(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 TK-3613, TK-3571, TK-3572, TK-3609, TK-3611, 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 and TK-3615 shall be controlled by the biofilter system at all times that the storage tanks are in operation.

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

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 TK-3613, TK-3571, TK-3572, TK-3609, TK-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 TK-3609, TK-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.32.4(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.32.4(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 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.32.4(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 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 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.

(The information describing the process contained in this emissions unit 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 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 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, K-103B, and K-103C; 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.

(The information describing the process contained in this emissions unit 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 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: (“Covered Flare” is defined at paragraph C.24(b)(22) and "BPP" means BP Products North America Inc. as defined at paragraph C.24(b)(88))

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 D.35.8.B.7 - D.35.8.B.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 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.xi to the operating permit. 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 D.35.8.B.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 in paragraph C.24(b).

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 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.x to the operating permit. 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 D.35.8.B.7 – D.35.8.B.9 and D.35.8.B.11 – D.35.8.B.12 shall meet or exceed the specifications set forth in Appendix FLR-11 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.xi to the operating permit.

16. Instrumentation and Monitoring Systems: Recording and Averaging Times. The instrumentation and monitoring systems identified in paragraphs D.35.8.B.7 – D.35.8.B.9 and D.35.8.B.11 - D.35.8.B.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 D.35.8.B.7 – D.35.8.B.9, D.35.8.B.11 – D.35.8.B.13, D.35.8.G.42.a, and D.35.8.G.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 paragraphs D.35.8.B.17.a — D.35.8.B.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 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.xi to the operating permit. If the excepted activities in paragraphs D.35.8.B.17.a — D.35.8.B.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”) of the Consent Decree entered in Civil No. 2:12-CV-00207 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, Subpart 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 paragraph D.35.8.L.70. All such requirements shall apply in accordance with the terms set forth in 40 C.F.R. Part 60, Subpart 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 paragraph D.35.8.D.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

Note: Paragraph 83.b.xii of the Consent Decree entered in Civil No. 2:12-CV-00207 does not list Paragraph D.23 of Appendix D as required to be incorporated into the operating permit. However, Paragraph D.35.8.L.70.a cites the FRGS tie-in dates in this Paragraph D.35.8.D.23.a with regard to determining the applicability of Subpart Ja to the Covered Flares. Therefore, Paragraph D.35.8.D.23 is incorporated into the permit as a way to determine compliance with Paragraph D.35.8.L.70.

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.

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 paragraph D.35.8.D.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 paragraphs D.35.8.E.26.a and/or D.35.8.E.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 paragraph D.35.8.E.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 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.xiv to the operating permit. 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 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.xiv to the operating permit.

c. EPA Response to Request. EPA shall evaluate any request under paragraph D.35.8.E.27.a on the basis of consistency with paragraphs D.35.8.E.27.a and D.35.8.E.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. Meaning and Calculation of "Waste Gas" Flow for Purposes of the Limitation on Flaring. For purposes of the meaning and calculation of "Waste Gas" flow in the limitations on flaring in paragraphs D.35.8.E.26 and D.35.8.E.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 paragraph D.35.8.E.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. By no later than November 6, 2012, 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 Condition D.35.8, 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

V_{max} 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 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.vi to the operating permit.

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.

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 D.35.8.B.7 – D.35.8.B.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 paragraph D.35.8.F.30.b. BPP manually may override the operation of the Automatic Control System required in paragraph D.35.8.F.30.b (for control of Total Steam Mass Rate) if the exception in paragraph D.35.8.H.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 D.35.8.F.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 Condition D.35.8.

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 D.35.8.H.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 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.iii to the operating permit to meet the requirements of this paragraph.

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 paragraph D.35.8.F.34.a, BPP is not subject to the emissions standard in that Subparagraph if the exception in paragraph D.35.8.H.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 D.35.8.F.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 paragraph D.35.8.F.35.b. or D.35.8.F.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 paragraph D.35.8.F.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 paragraph D.35.8.F.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 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.v to the operating permit. 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 paragraphs D.35.8.F.35.b and D.35.8.F.35.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 D.35.8.H.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 D.35.8.F.33 – D.35.8.F.35.

37. Inapplicability of paragraphs D.35.8.F.33 – D.35.8.F.36. The requirements of paragraphs D.35.8.F.33 – D.35.8.F.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.

40. Combustion Efficiency (CE) Multipliers for Calculating the $NHV_{cz\text{-}limit}$ that replace those listed in Table 2 of Appendix FLR-3 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.iii of the operating permit. BPP shall operate each Covered Flare to comply with the EPA-established "A" CE multiplier from the letter to BP from the Department of Justice, dated December 11, 2018, as listed below.

    a. Alky Flare: 6.6.

    b. DDU Flare: 6.1.

    c. VRU Flare: 6.6.

    d. FCU Flare: 6.1.

    e. South Flare: 6.1.

    f. GOHT Flare: 6.1.

    g. 4UF Flare: 6.1.

    h. UIU Flare: 6.1.

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 D.35.8.B.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. NHV_{vg} (in BTU/scf)
        v. NHV_{cz} (in BTU/scf)
        vi. $NHV_{cz\text{-}limit}$ (in BTU/scf)

    b. By no later than June 30, 2014, for all Covered Flares, commencing if and when any instrument subject to paragraph D.35.8.B.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 D.35.8.F.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 D.35.8.F.29, D.35.8.F.33 - D.35.8.F.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 Condition D.35.8, and except with respect to the data produced by video cameras required pursuant to paragraph D.35.8.B.13, BPP shall retain all records created pursuant to this Condition D.35.8, including the raw data values, in accordance with Part VIII ("Reporting and Recordkeeping") of the Consent Decree entered in Civil No. 2:12-CV-00207 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 D.35.8.B.13 for six months except that BPP shall comply with the data retention requirements in Part VIII of the Consent Decree entered in Civil No. 2:12-CV-00207 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 November 6, 2012, 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 D.35.8.G.45; and

d. In the semi-annual report required under Paragraph 98 of Part VIII of the Consent Decree entered in Civil No. 2:12-CV-00207 that is the first one due after one year after November 6, 2012, provide a detailed description of the installations made in compliance with paragraphs D.35.8.G.42.a. and D.35.8.G.42.b, including the specific models and manufacturers.

44. Emission Standards Applicable to the LPG Flare. By no later than one year after November 6, 2012, BPP shall comply with each of the requirements in paragraph D.35.8.F.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 paragraph D.35.8.F.29.d.

45. Standard for $\dot{m}_{air\text{-}asst}/\dot{m}_{air\text{-}stoich\text{-}vg}$. By no later than one year after November 6, 2012 and continuing through to either: (i) the date that EPA sets a new limit pursuant to either Subparagraph 48.d or 49.b of the Consent Decree entered in Civil No. 2:12-CV-00207; 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 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.xv to the operating permit, 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 D.35.8.H.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 November 6, 2012, 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 Condition D.35.8.

48. RESERVED

H. Exception for Instrument Downtime

51. A failure to comply with the work practices or standards in paragraphs D.35.8.F.30.b, D.35.8.F.33.b, D.35.8.F.34.a, D.35.8.F.35.b, D.35.8.F.35.c, or D.35.8.G.45 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 paragraphs D.35.8.H.51.a. through D.35.8.H.51.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 of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207, incorporated as Attachment F.xi to the operating permit.

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 Condition D.35.8 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 Condition D.35.8 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 Condition D.35.8 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 83.b.xii of the Consent Decree entered in Civil No. 2:12-CV-00207 does not list Paragraph K.67.a, b, and e of Appendix D as required to be incorporated into the operating permit. However, Paragraph D.35.8.K.67.b defines the terms "planned" and "unplanned" with regard to an outage of a Covered Flares. Therefore, Paragraphs D.35.8.K.67.a and b are incorporated into the permit as a way to determine compliance with Paragraphs D.35.8.K.67.c and d. Paragraph D.35.8.K.67.e is incorporated pursuant to 326 IAC 2-7-5(3) and retained in the present condition for consistency with usage in the Consent Decree.

L. NSPS Subparts A and Ja Applicability for Flares

69. RESERVED

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 November 6, 2012 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 D.35.8.D.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 paragraph D.35.8.L.70.a, the requirements in Sections I. and J. of Appendix D to the Consent Decree entered in Civil No. 2:12-CV-00207 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 also include insignificant activities listed in Section A.4 of this permit.

(1) As part of the WEP, there are new piping connections (valves and flanges).

(The information describing the process contained in this emissions unit 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 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 [326 IAC 2-7-5(1)]

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 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)(J)(vi)(CC)] [326 IAC 8-3-2] [326 IAC 8-3-5].

(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:

Insignificant Activities:

(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 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.

A stage II vapor recovery system was decommissioned in accordance with 326 IAC 8-4-6(d).

(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 that extends to not more than:

(1) Twelve (12) inches from the bottom of the storage tank if the fill pipe was installed on or before November 9, 2006; or

(2) Six (6) inches from the bottom of the storage tank if the fill pipe was installed after November 9, 2006.

(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) If employees of the Permittee are not present during loading, it shall be the responsibility of the owner or the operator of the transport to make certain the vapor balance system is:

(1) Connected between the transport and the storage tank; and

(2) Operating according to manufacturer's specifications.

D.39.2 Volatile Organic Compounds [326 IAC 8-4-6(e)] [326 IAC 8-4-6(d)]

(a) Pursuant to 326 IAC 8-4-6(e)(2), a stage II vapor recovery system is not required in Lake County for a gasoline dispensing facility that has been decommissioned in accordance with 326 IAC 8-4-6(d).

(b) A stage II vapor recovery system at a gasoline dispensing facility in Clark, Floyd, Lake, or Porter counties must be maintained in accordance with 326 IAC 8-4-6(c), unless the owner or operator decommissions the stage II vapor recovery system as follows:

(1) The owner or operator shall notify the department of the intent to decommission the stage II vapor recovery system. The Permittee notified IDEM of its intent to decommission the stage II vapor recovery system in accordance with section 14 of the 2009 "Recommended Practices for Installation and Testing of Vapor Recovery Systems at Vehicle Refueling Sites"* of the Petroleum Equipment Institute on October 13, 2020.

(2) The owner or operator shall decommission the stage II vapor recovery system in accordance with section 14 of the 2009 "Recommended Practices for Installation and Testing of Vapor Recovery Systems at Vehicle Refueling Sites"* of the Petroleum Equipment Institute.

(3) The owner or operator shall complete decommissioning within one hundred (100) calendar days from notification to the department.

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

D.39.3 RESERVED

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

D.39.4 Reporting Requirements

Pursuant to 326 IAC 8-4-6(f), upon request by IDEM, the Permittee shall submit records to the agency within thirty (30) calendar days from the date of the request that demonstrate that the gasoline dispensing facility is exempt from 326 IAC 8-4-6(c).

SECTION D.40 EMISSIONS UNIT OPERATION CONDITIONS – CALUMET WAREHOUSE

Emissions Unit Description:

Insignificant Activities:

(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.

(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 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	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).

(The information describing the process contained in this emissions unit 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) RESERVED

(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) RESERVED

(g) RESERVED

(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.

Additional limits on firing rate, SO_2, NOx, and CO for the GOHT heaters (F-901A and F-901B) are in Section D.01.

Compliance with the NO_X, 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 NO_X, 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.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 [326 IAC 2-7-5(1)]

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 and to demonstrate compliance with Conditions D.01.1 and D.42.2, 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 and to demonstrate compliance with Conditions D.01.1 and D.42.2, 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.01.1 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) RESERVED

(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 contains the Permittee's obligations with regard to the records required by Paragraphs (a) 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) RESERVED

(c) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.01.1 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) 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 Linde 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-9210 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.

(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 [326 IAC 2-7-5(1)]

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 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 – Pump Engines and Concrete Crusher

Emissions Unit Description:

(ee) Diesel-fired engines, as follows:

(1) One (1) emergency fire pump engine, identified as Firepump Engine 1 (PU-300B), a 2010 model year engine permitted and installed in 2012, with a maximum capacity of 359 HP. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ]

(2) Two (2) non-emergency pump engines, identified as Pump Engine 2 (P-31) and Pump Engine 3 (P-32), 2010 model year engines permitted and installed in 2012, each with a maximum capacity of 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.

(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 Engine 1 (PU-300B), Pump Engine 2 (P-31), Pump Engine 3 (P-32) 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 Firepump Engine 1 (PU-300B), Pump Engine 2 (P-31), and Pump Engine 3 (P-32) shall not exceed 500 hours per year, each.

(b) The total amount of concrete processed by the concrete crusher shall not exceed 18,000 tons.

Compliance with the emissions limits at Firepump Engine 1 (PU-300B), Pump Engine 2 (P-31), and Pump Engine 3 (P-32) 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 D.46 EMISSIONS UNIT OPERATION CONDITIONS –Naphtha Hydrotreater

Emissions Unit Description:

(pp) The Naphtha Hydrotreater (NHT), identified as Unit ID 810, approved in 2016 for construction, removes sulfur from petroleum naphthas. Petroleum naphthas are heated and sent through a Selective Hydrotreating Unit (SHU) reactor, D-701, to prevent fouling downstream and to treat diolefins. The SHU reactor effluent is routed to a Hydrodesulfurization (HDS) reactor, D-702, to further reduce sulfur content. The HDS reactor effluent is cooled, and the HDS reactor's vapor stream is sent to the amine absorber tower, C-701, to remove H2S from the unreacted hydrogen prior to being recycled within the NHT unit and purged as needed to the hydrogen header system. The HDS reactor's liquid stream is sent to the stabilizer distillation column, C-702, to separate lighter components entrained in the desulfurized naphtha. Additional sulfur is removed from the stabilizer's off-gas at the stabilizer off-gas amine contactor tower, C-703, prior to being recycled to the fuel gas system. Desulfurized naphtha is pumped to the tank fields for gasoline blending. Sulfur containing sour water and amine streams are sent to the SRP. The NHT includes the following sources of emissions:

(1) One (1) hydrodesulfurization (HDS) reactor heater, identified as F-701, with a maximum rated capacity of 104.2 mmBTU/hr, with emissions uncontrolled and exhausting to stack 810-01. The HDS reactor heater is equipped with low-NO_X burners, a NOx CEMS, has natural gas-fired pilot lights, and burns refinery fuel gas. The HDS reactor heater provides heat for the HDS reactor feed and effluent streams.

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

(3) The NHT Unit is connected to the GOHT Flare and associated flare gas recovery system FGRS 2 (included in Section D.35). This system is used to recover or control VOC emissions during emergency situations, unit startups and shutdowns.

(4) As part of the WEP, there are new piping connections (valves and flanges).

(The information describing the process contained in this facility description box is descriptive information and does not constitute enforceable conditions.)

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

D.46.1 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2, particulate matter emissions from the HDS Reactor Heater F-701 shall not exceed 0.03 grains per dry standard cubic foot.

D.46.2 Prevention of Significant Deterioration [326 IAC 2-2] and Emission Offset [326 IAC 2-3] Minor Limits

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

(a) The firing rate of the HDS Reactor Heater F-701 shall not exceed 912,792 million BTU per twelve (12) consecutive month period, with compliance determined at the end of each month.

(b) The Permittee shall control leaks of VOC from pumps, compressors, valves, process drains, and pressure relief devices of the NHT process according to the Leak Detection and Repair (LDAR) Plan submitted by the Permittee that meets the requirements of 326 IAC 8-4-8 (Leaks From Petroleum Refineries; Monitoring; Recordkeeping), and shall comply with the applicable requirements of Section F.9 - 40 CFR Part 60, Subpart GGGa (NSPS for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After November 7, 2006) and 40 CFR Part 60, Subpart VVa (NSPS for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After November 7, 2006), and Section F.11 - 40 CFR Part 60, Subpart QQQ (NSPS for VOC Emissions for Petroleum Refinery Wastewater Systems), Section H.2 - 40 CFR Part 63, Subpart CC (NESHAP for Petroleum Refineries).

Compliance with the limits shall ensure that the emissions increases, including fugitive emissions, for VOC for the Clean Fuel Project (NHT unit) remain below the significant levels, rendering 326 IAC 2-2 and 326 IAC 2-3 not applicable for this pollutant.

D.46.3 Volatile Organic Compounds (VOC) [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.46.4 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.

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

D.46.5 Continuous Emissions Monitoring

The NOx continuous emission monitoring systems (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.46.6 Monitoring for Equipment Leaks of VOC [326 IAC 8-4-8]

Pursuant to 326 IAC 8-4-8, the Permittee shall monitor for leaks of VOC according to the LDAR plan submitted by the Permittee.

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

D.46.7 Record Keeping Requirements

(a) To document the compliance status with Condition D.46.2(a), the Permittee shall maintain monthly records of the firing rate of the HDS Reactor Heater F-701.

(b) To document the compliance status with Condition D.46.2(b) and pursuant to 326 IAC 8-4-8, the Permittee shall keep records as specified in the LDAR plan.

(c) Pursuant to 326 IAC 3-5-6 and to document the compliance status with Conditions D.46.5, 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.

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

D.46.8 Reporting Requirements

(a) A quarterly summary of the information to document the compliance status with Condition D.46.2(a) 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, the Permittee shall comply with equipment leak reporting requirements specified in the LDAR plan.

(c) Pursuant to 326 IAC 3-5-7 and to document the compliance status with Conditions D.46.5, C.12, and C.13, the Permittee shall submit reports of excess NOx emissions at the HDS Reactor Heater F-701not 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) 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.47 EMISSIONS UNIT OPERATION CONDITIONS – Radio Tower Emergency Generator Engines

Emissions Unit Description:

(ii) Two (2) propane-fired emergency generator engines, identified as Radio Tower Emergency Engine 1 and Radio Tower Emergency Engine 2, permitted in 2019, each with a maximum capacity of 230 HP. [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

(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.47.1 Particulate Matter [326 IAC 6.8-1-2]

Pursuant to 326 IAC 6.8-1-2, particulate matter emissions from Radio Tower Emergency Engine 1 and Radio Tower Emergency Engine 2 shall not exceed 0.03 grains per dry standard cubic foot.

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
- T-400 Brine Stripper Tower

(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. As part of the WEP, there will be new control valves, instrumentation upgrades (valves, flanges) and new piping connections (valves, flanges). 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. As part of WEP, there will be rerouting of naphtha streams (valves and flanges), removal of hydraulic constraints (pump modifications), and new piping connections (valves and flanges). 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, approved in 2016 for modification. 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. As part of WEP, there are tray modifications in distillation towers and new piping connections (valve and flanges). 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-407 Rich Amine Flash Drum
- D-407A Rich Amine Flashed Gas Knock Out Drum
- 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. As part of the WEP, there are modifications to trays and new nozzles for the distillation towers, and new piping connections (valves and flanges). 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. As part of the WEP, there are removal of hydraulic constraints (pump modification) and new piping connections (valves and flanges). 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°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°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)

(pp) The Naphtha Hydrotreater (NHT), identified as Unit ID 810, approved in 2016 for construction, removes sulfur from petroleum naphthas. Petroleum naphthas are heated and sent through a Selective Hydrotreating Unit (SHU) reactor, D-701, to prevent fouling downstream and to treat diolefins. The SHU reactor effluent is routed to a Hydrodesulfurization (HDS) reactor, D-702, to further reduce sulfur content. The HDS reactor effluent is cooled, and the HDS reactor's vapor stream is sent to the amine absorber tower, C-701, to remove H2S from the unreacted hydrogen prior to being recycled within the NHT unit and purged as needed to the hydrogen header system. The HDS reactor's liquid stream is sent to the stabilizer distillation column, C-702, to separate lighter components entrained in the desulfurized naphtha. Additional sulfur is removed from the stabilizer's off-gas at the stabilizer off-gas amine contactor tower, C-703, prior to being recycled to the fuel gas system. Desulfurized naphtha is pumped to the tank fields for gasoline blending. Sulfur containing sour water and amine streams are sent to the SRP. [Section D.46]

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.)

Consolidated Federal Air Rule [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 to the operating 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
- T-400 Brine Stripper Tower

(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. As part of the WEP, there will be new control valves, instrumentation upgrades (valves, flanges) and new piping connections (valves, flanges). 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. As part of WEP, there will be rerouting of naphtha streams (valves and flanges), removal of hydraulic constraints (pump modifications), and new piping connections (valves and flanges). 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, approved in 2016 for modification. 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. As part of WEP, there are tray modifications in distillation towers and new piping connections (valve and flanges). 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-407 Rich Amine Flash Drum
- D-407A Rich Amine Flashed Gas Knock Out Drum
- 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. As part of the WEP, there are modifications to trays and new nozzles for the distillation towers, and new piping connections (valves and flanges). 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. As part of the WEP, there are removal of hydraulic constraints (pump modification) and new piping connections (valves and flanges). 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°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°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

(pp) The Naphtha Hydrotreater (NHT), identified as Unit ID 810, approved in 2016 for construction, removes sulfur from petroleum naphthas. Petroleum naphthas are heated and sent through a Selective Hydrotreating Unit (SHU) reactor, D-701, to prevent fouling downstream and to treat diolefins. The SHU reactor effluent is routed to a Hydrodesulfurization (HDS) reactor, D-702, to further reduce sulfur content. The HDS reactor effluent is cooled, and the HDS reactor's vapor stream is sent to the amine absorber tower, C-701, to remove H_2S from the unreacted hydrogen prior to being recycled within the NHT unit and purged as needed to the hydrogen header system.

The HDS reactor's liquid stream is sent to the stabilizer distillation column, C-702, to separate lighter components entrained in the desulfurized naphtha. Additional sulfur is removed from the stabilizer's off-gas at the stabilizer off-gas amine contactor tower, C-703, prior to being recycled to the fuel gas system. Desulfurized naphtha is pumped to the tank fields for gasoline blending. Sulfur containing sour water and amine streams are sent to the SRP. [Section D.46]

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.)

Consolidated Federal Air Rule [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 to the operating 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
- T-400 Brine Stripper Tower
- E-400A/B Stripper Overhead Condensers at the BCS
- D-400 Stripper Overhead Receiver at the BCS
- D-401 Liquid Ring Separator at the BCS
- K-400A/B/C Overhead Gas Compressors at the BCS
- D-402 Second Stage Liquid Ring Separator Drum at the BCS
- D-403 Oil Skimming Drum at the BCS
- K-401A Compressor at the BCS
- K-401B Compressor at the BCS

(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. As part of the WEP, there will be new control valves, instrumentation upgrades (valves, flanges) and new piping connections (valves, flanges). 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. As part of WEP, there will be rerouting of naphtha streams (valves and flanges), removal of hydraulic constraints (pump modifications), and new piping connections (valves and flanges). 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, approved in 2016 for modification. 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. As part of WEP, there are tray modifications in distillation towers and new piping connections (valve and flanges). 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-407 Rich Amine Flash Drum
- D-407A Rich Amine Flashed Gas Knock Out 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. As part of the WEP, there are modifications to trays and new nozzles for the distillation towers, and new piping connections (valves and flanges). 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. As part of the WEP, there are removal of hydraulic constraints (pump modification) and new piping connections (valves and flanges) . 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°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°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)

(pp) The Naphtha Hydrotreater (NHT), identified as Unit ID 810, approved in 2016 for construction, removes sulfur from petroleum naphthas. Petroleum naphthas are heated and sent through a Selective Hydrotreating Unit (SHU) reactor, D-701, to prevent fouling downstream and to treat diolefins. The SHU reactor effluent is routed to a Hydrodesulfurization (HDS) reactor, D-702, to further reduce sulfur content. The HDS reactor effluent is cooled, and the HDS reactor's vapor stream is sent to the amine absorber tower, C-701, to remove H2S from the unreacted hydrogen prior to being recycled within the NHT unit and purged as needed to the hydrogen header system. The HDS reactor's liquid stream is sent to the stabilizer distillation column, C-702, to separate lighter components entrained in the desulfurized naphtha. Additional sulfur is removed from the stabilizer's off-gas at the stabilizer off-gas amine contactor tower, C-703, prior to being recycled to the fuel gas system. Desulfurized naphtha is pumped to the tank fields for gasoline blending. Sulfur containing sour water and amine streams are sent to the SRP. [Section D.46]

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.)

Consolidated Federal Air Rule [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 to the operating 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.)

New Source Performance Standards (NSPS) Requirements [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 the operating 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) RESERVED

(oo) The New Hydrogen Unit (New HU), identified as Unit ID 801, owned and operated by Linde 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.)

New Source Performance Standards (NSPS) Requirements [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 the operating 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

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. As part of the WEP, there will be new control valves, instrumentation upgrades (valves, flanges) and new piping connections (valves, flanges). 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. As part of the WEP, there are removal of hydraulic constraints (pump modification) and new piping connections (valves and flanges). 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°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°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 Linde 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.

(pp) The Naphtha Hydrotreater (NHT), identified as Unit ID 810, approved in 2016 for construction, removes sulfur from petroleum naphthas. Petroleum naphthas are heated and sent through a Selective Hydrotreating Unit (SHU) reactor, D-701, to prevent fouling downstream and to treat diolefins. The SHU reactor effluent is routed to a Hydrodesulfurization (HDS) reactor, D-702, to further reduce sulfur content. The HDS reactor effluent is cooled, and the HDS reactor's vapor stream is sent to the amine absorber tower, C-701, to remove H2S from the unreacted hydrogen prior to being recycled within the NHT unit and purged as needed to the hydrogen header system. The HDS reactor's liquid stream is sent to the stabilizer distillation column, C-702, to separate lighter components entrained in the desulfurized naphtha. Additional sulfur is removed from the stabilizer's off-gas at the stabilizer off-gas amine contactor tower, C-703, prior to being recycled to the fuel gas system. Desulfurized naphtha is pumped to the tank fields for gasoline blending. Sulfur containing sour water and amine streams are sent to the SRP. [Section D.46]

- F-701 HDS Reactor Heater

Under 40 CFR Part 60, Subpart Ja 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.)

New Source Performance Standards (NSPS) Requirements [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 the operating 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.)

New Source Performance Standards (NSPS) Requirements [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 the operating 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.)

New Source Performance Standards (NSPS) Requirements [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 the operating 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 3483 (approved in 2018 for construction)
- Tank 3484 (constructed in 1996)
- Tank 3484 (replacement, approved in 2021 for construction)
- 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.)

New Source Performance Standards (NSPS) Requirements [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]

Upon replacement, tank TK-3483 (approved in 2018 for construction) will become subject to 40 CFR Part 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 the operating 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
- TK-6126
- TK-6127

(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]

- TK-3613
- TK-3614
- TK-3615
- TK-3609

Under 40 CFR Part 60, Subpart UU, the above units are affected facilities.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [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 the operating 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.)

New Source Performance Standards (NSPS) Requirements [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 January 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 the operating 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 the operating 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.

- K-400A
- K-400B
- K-400C
- K-401A
- K-401B

Under 40 CFR 60, Subpart GGGa, the compressors listed above are an 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. As part of the WEP, there will be new control valves, instrumentation upgrades (valves, flanges) and new piping connections (valves, flanges). 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 compressors listed above are affected facilities.

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.

(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. As part of WEP, there will be rerouting of naphtha streams (valves and flanges), removal of hydraulic constraints (pump modifications), and new piping connections (valves and flanges). 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, approved in 2016 for modification. 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. As part of the WEP, there are tray modifications in distillation towers and new piping connections (valves and flanges). 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. As part of the WEP, there are modifications to trays and new nozzles for the distillation towers, and new piping connections (valves and flanges). 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, and 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. As part of the WEP, there are removal of hydraulic constraints (pump modification) and new piping connections (valves and flanges). 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°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°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) RESERVED

(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-103C
- 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 compressors listed above 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 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 Linde 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

(pp) The Naphtha Hydrotreater (NHT), identified as Unit ID 810, approved in 2016 for construction, removes sulfur from petroleum naphthas. Petroleum naphthas are heated and sent through a Selective Hydrotreating Unit (SHU) reactor, D-701, to prevent fouling downstream and to treat diolefins. The SHU reactor effluent is routed to a Hydrodesulfurization (HDS) reactor, D-702, to further reduce sulfur content. The HDS reactor effluent is cooled, and the HDS reactor's vapor stream is sent to the amine absorber tower, C-701, to remove H2S from the unreacted hydrogen prior to being recycled within the NHT unit and purged as needed to the hydrogen header system. The HDS reactor's liquid stream is sent to the stabilizer distillation column, C-702, to separate lighter components entrained in the desulfurized naphtha. Additional sulfur is removed from the stabilizer's off-gas at the stabilizer off-gas amine contactor tower, C-703, prior to being recycled to the fuel gas system. Desulfurized naphtha is pumped to the tank fields for gasoline blending. Sulfur containing sour water and amine streams are sent to the SRP. [Section D.46]

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.

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [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 the operating 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 the operating 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
- T-400 Brine Stripper

(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. As part of the WEP, there will be new control valves, instrumentation upgrades (valves, flanges) and new piping connections (valves, flanges). 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. As part of WEP, there will be rerouting of naphtha streams (valves and flanges), removal of hydraulic constraints (pump modifications), and new piping connections (valves and flanges). 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, approved in 2016 for modification. 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. As part of WEP, there are tray modifications in distillation towers and new piping connections (valve and flanges). The following specific units are considered to be affected facilities: [Section D.6]

- T-401 Absorber
- T-403 Sponge Adsorber
- T-405 Coker Produict Gas Amine Scrubber

- T-404 Debutanizer
- T-406 C3/C4 Amine Contactor
- T-407 Splitter T-407 Splitter
- D-407 Rich Amine Flash Drum
- D-407A Rich Amine Flashed Gas Knock Out Drum
- 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. As part of the WEP, there are modifications to trays and new nozzles for the distillation towers, and new piping connections (valves and flanges). 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. As part of the WEP, there are removal of hydraulic constraints (pump modification) and new piping connections (valves and flanges). 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°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°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

(pp) The Naphtha Hydrotreater (NHT), identified as Unit ID 810, approved in 2016 for construction, removes sulfur from petroleum naphthas. Petroleum naphthas are heated and sent through a Selective Hydrotreating Unit (SHU) reactor, D-701, to prevent fouling downstream and to treat diolefins. The SHU reactor effluent is routed to a Hydrodesulfurization (HDS) reactor, D-702, to further reduce sulfur content. The HDS reactor effluent is cooled, and the HDS reactor's vapor stream is sent to the amine absorber tower, C-701, to remove H2S from the unreacted hydrogen prior to being recycled within the NHT unit and purged as needed to the hydrogen header system. The HDS reactor's liquid stream is sent to the stabilizer distillation column, C-702, to separate lighter components entrained in the desulfurized naphtha. Additional sulfur is removed from the stabilizer's off-gas at the stabilizer off-gas amine contactor tower, C-703, prior to being recycled to the fuel gas system.

Desulfurized naphtha is pumped to the tank fields for gasoline blending. Sulfur containing sour water and amine streams are sent to the SRP. [Section D.46]

- C-701 Amine Absorber Tower
- C-702 Stabilizer Distillation Column
- C-703 Stabilizer Off-Gas Amine Contact Tower

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.)

New Source Performance Standards (NSPS) Requirements [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 Organic 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 the operating permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.660 (a), (b), (c)(1-3), (c)(5), (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. As part of the WEP, there will be new control valves, instrumentation upgrades (valves, flanges) and new piping connections (valves, flanges). 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. As part of WEP, there will be rerouting of naphtha streams (valves and flanges), removal of hydraulic constraints (pump modifications), and new piping connections (valves and flanges). 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, approved in 2016 for modification. 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. As part of WEP, there are tray modifications in distillation towers and new piping connections (valve and flanges). 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. As part of the WEP, there are modifications to trays and new nozzles for the distillation towers, and new piping connections (valves and flanges). 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. As part of the WEP, there are removal of hydraulic constraints (pump modification) and new piping connections (valves and flanges). 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°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 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°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 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 Flotation (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.

(pp) The Naphtha Hydrotreater (NHT), identified as Unit ID 810, approved in 2016 for construction, removes sulfur from petroleum naphthas. Petroleum naphthas are heated and sent through a Selective Hydrotreating Unit (SHU) reactor, D-701, to prevent fouling downstream and to treat diolefins. The SHU reactor effluent is routed to a Hydrodesulfurization (HDS) reactor, D-702, to further reduce sulfur content. The HDS reactor effluent is cooled, and the HDS reactor's vapor stream is sent to the amine absorber tower, C-701, to remove H2S from the unreacted hydrogen prior to being recycled within the NHT unit and purged as needed to the hydrogen header system. The HDS reactor's liquid stream is sent to the stabilizer distillation column, C-702, to separate lighter components entrained in the desulfurized naphtha. Additional sulfur is removed from the stabilizer's off-gas at the stabilizer off-gas amine contactor tower, C-703, prior to being recycled to the fuel gas system. Desulfurized naphtha is pumped to the tank fields for gasoline blending. Sulfur containing sour water and amine streams are sent to the SRP. [Section D.46]

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.)

New Source Performance Standards (NSPS) Requirements [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 Petroleum 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 the operating 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 Petroleum Refinery Wastewater Systems Modification Requirements [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, approved in 2016 for modification. 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. As part of WEP, there are tray modifications in distillation towers and new piping connections (valve and flanges). 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. As part of the WEP, there are removal of hydraulic constraints (pump modification) and new piping connections (valves and flanges). 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°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°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

(pp) The Naphtha Hydrotreater (NHT), identified as Unit ID 810, approved in 2016 for construction, removes sulfur from petroleum naphthas. Petroleum naphthas are heated and sent through a Selective Hydrotreating Unit (SHU) reactor, D-701, to prevent fouling downstream and to treat diolefins. The SHU reactor effluent is routed to a Hydrodesulfurization (HDS) reactor, D-702, to further reduce sulfur content. The HDS reactor effluent is cooled, and the HDS reactor's vapor stream is sent to the amine absorber tower, C-701, to remove H2S from the unreacted hydrogen prior to being recycled within the NHT unit and purged as needed to the hydrogen header system. The HDS reactor's liquid stream is sent to the stabilizer distillation column, C-702, to separate lighter components entrained in the desulfurized naphtha. Additional sulfur is removed from the stabilizer's off-gas at the stabilizer off-gas amine contactor tower, C-703, prior to being recycled to the fuel gas system. Desulfurized naphtha is pumped to the tank fields for gasoline blending. Sulfur containing sour water and amine streams are sent to the SRP. [Section D.46]

- D-701 SHU Reactor
- D-702 HDS Reactor

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.)

New Source Performance Standards (NSPS) Requirements [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 the operating permit), for the emission unit(s) listed above as specified as follows.

1. 40 CFR 60.700 (a), (b), (c)(1), (c)(3), (c)(5-7), (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 Linde 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:

(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 equal to or less than five hundred thousand (500,000) British thermal units per hour except where total capacity of equipment operated by one (1) stationary source as defined in 326 IAC 2-7-1(39) exceeds two million (2,000,000) British thermal units per hour. [326 IAC 2-7-1(21)(J)(i)(BB)] [40 CFR 60, Subpart IIII] [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

(y) Activities associated with emergencies, as follows:

(2) Emergency generators as follows: [326 IAC 2-7-1(21)(J)(xxii)(BB)]

(B) Diesel Generators not exceeding one thousand six hundred (1,600) horsepower. [326 IAC 2-7-1(21)(J)(xxii)(BB)(bb)] [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ]

(3) Stationary fire pump engines. [326 IAC 2-7-1(21)(J)(xxii)(CC)] [40 CFR 60, Subpart IIII] [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

(ee) Diesel-fired pump engines, as follows:

(1) One (1) emergency fire pump engine, identified as Firepump Engine 1 (PU-300B), a 2010 model year engine permitted and installed in 2012, with a maximum capacity of 359 HP. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ]

(2) Two (2) non-emergency pump engines, identified as Pump Engine 2 (P-31) and Pump Engine 3 (P-32), 2010 model year engines permitted and installed in 2012, each with a maximum capacity of 460 HP. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [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 the operating 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 F.14 EMISSIONS UNIT OPERATION CONDITIONS - 40 CFR 60, Subpart JJJJ

Emissions Unit Description:

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 equal to or less than five hundred thousand (500,000) British thermal units per hour except where total capacity of equipment operated by one (1) stationary source as defined in 326 IAC 2-7-1(39) exceeds two million (2,000,000) British thermal units per hour. [326 IAC 2-7-1(21)(J)(i)(BB)] [40 CFR 60, Subpart IIII] [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

(y) Other activities associated with emergencies, as follows:

(2) Emergency generators as follows: [326 IAC 2-7-1(21)(J)(xxii)(BB)]

(A) Gasoline generators not exceeding one hundred ten (110) horsepower; [326 IAC 2-7-1(21)(J)(xxii)(BB)(aa)] [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

(C) Natural gas turbines or reciprocating engines not exceeding sixteen thousand (16,000) horsepower. [326 IAC 2-7-1(21)(J)(xxii)(BB)(cc)] [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

(3) Stationary fire pump engines. [326 IAC 2-7-1(21)(J)(xxii)(CC)] [40 CFR 60, Subpart IIII] [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

(ii) Two (2) propane-fired emergency generator engines, identified as Radio Tower Emergency Engine 1 and Radio Tower Emergency Engine 2, permitted in 2019, each with a maximum capacity of 230 HP. [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

(The information describing the process contained in this emissions unit description box is descriptive information and does not constitute enforceable conditions.)

New Source Performance Standards (NSPS) Requirements [326 IAC 2-7-5(1)]

F.14.1 General Provisions Relating to New Source Performance Standards [326 IAC 12-1] [40 CFR Part 60, Subpart A]

(a) Pursuant to 40 CFR 60.1, the Permittee shall comply with the provisions of 40 CFR Part 60, Subpart A – General Provisions, which are incorporated by reference as 326 IAC 12-1, for the emission unit(s) listed above, except as otherwise specified in 40 CFR Part 60, Subpart JJJJ.

(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.14.2 Standards of Performance for Stationary Spark Ignition Internal Combustion Engines NSPS [326 IAC 12] [40 CFR Part 60, Subpart JJJJ]

The Permittee shall comply with the following provisions of 40 CFR Part 60, Subpart JJJJ (included as Attachment C.XVII to the operating permit), which are incorporated by reference as 326 IAC 12, for the emission unit(s) listed above:

(1) 40 CFR 60.4230
(2) 40 CFR 60.4233
(3) 40 CFR 60.4234
(4) 40 CFR 60.4235
(5) 40 CFR 60.4236
(6) 40 CFR 60.4237
(7) 40 CFR 60.4243
(8) 40 CFR 60.4244
(9) 40 CFR 60.4245
(10) 40 CFR 60.4246
(11) 40 CFR 60.4248
(12) Table 1 to Subpart JJJJ of Part 60
(13) Table 2 to Subpart JJJJ of Part 60
(14) Table 3 to Subpart JJJJ of Part 60

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 the operating 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 the operating 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. As part of the WEP, there will be new control valves, instrumentation upgrades (valves, flanges) and new piping connections (valves, flanges). 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. As part of WEP, there will be rerouting of naphtha streams (valves and flanges), removal of hydraulic constraints (pump modifications), and new piping connections (valves and flanges).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, approved in 2016 for modification. 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. As part of WEP, there are tray modifications in distillation towers

and new piping connections (valve and flanges). 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. As part of the WEP, there are modifications to trays and new nozzles for the distillation towers, and new piping connections (valves and flanges). 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. As part of the WEP, there are removal of hydraulic constraints (pump modification) and new piping connections (valves and flanges). 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°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°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 Flotation (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 Flotation (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
- TK-3624

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.

(pp) The Naphtha Hydrotreater (NHT), identified as Unit ID 810, approved in 2016 for construction, removes sulfur from petroleum naphthas. Petroleum naphthas are heated and sent through a Selective Hydrotreating Unit (SHU) reactor, D-701, to prevent fouling downstream and to treat diolefins. The SHU reactor effluent is routed to a Hydrodesulfurization (HDS) reactor, D-702, to further reduce sulfur content. The HDS reactor effluent is cooled, and the HDS reactor's vapor stream is sent to the amine absorber tower, C-701, to remove H2S from the unreacted hydrogen prior to being recycled within the NHT unit and purged as needed to the hydrogen header system. The HDS reactor's liquid stream is sent to the stabilizer distillation column, C-702, to separate lighter components entrained in the desulfurized naphtha. Additional sulfur is removed from the stabilizer's off-gas at the stabilizer off-gas amine contactor tower, C-703, prior to being recycled to the fuel gas system. Desulfurized naphtha is pumped to the tank fields for gasoline blending. Sulfur containing sour water and amine streams are sent to the SRP. [Section D.46]

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 the operating 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 the operating 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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.
- 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]

- 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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.
- All delayed coking units meeting the criteria of 40 CFR 63, Subpart CC.

The following are Group 2 storage vessels:

- TK-6254
- TK-6126
- TK-6127

(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. As part of the WEP, there will be new control valves, instrumentation upgrades (valves, flanges) and new piping connections (valves, flanges). 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 including maintenance 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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 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. As part of WEP, there will be rerouting of naphtha streams (valves and flanges), removal of hydraulic constraints (pump modifications), and new piping connections (valves and flanges).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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.

(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 including maintenance 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, approved in 2016 for modification. 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. As part of WEP, there are tray modifications in distillation towers and new piping connections (valve and flanges). 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 including maintenance 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 including maintenance 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. As part of the WEP, there are modifications to trays and new nozzles for the distillation towers, and new piping connections (valves and flanges). 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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.

(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 including maintenance 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 including maintenance 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. As part of the WEP, there are removal of hydraulic constraints (pump modification) and new piping connections (valves and flanges) . 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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.

(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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.

(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 including maintenance 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 including maintenance 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 including maintenance 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 H_2S. 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 including maintenance 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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.

(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 including maintenance 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°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]

- 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 including maintenance 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°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]

- 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 including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.

(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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.

(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 Flotation (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 Flotation (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 Flotation (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 including maintenance 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 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
- TK-3711
- TK-3712
- 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-3610
- TK-3611
- TK-3613
- TK-3490
- Tank 3495
- TK-3717
- TK-3721
- TK-3498
- TK-3717R
- TK-3721R
- TK-3498R
- TK-3720
- TK-3497
- TK-3506
- TK-3710

(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) RESERVED

(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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.

The following Group 2 storage vessels meeting the criteria specified in 40 CFR 63, Subpart CC:

- TK-3609
- 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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.

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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.

(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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.

(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 including maintenance 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 Linde 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.
- All miscellaneous process vents including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC.

(pp) The Naphtha Hydrotreater (NHT), identified as Unit ID 810, approved in 2016 for construction, removes sulfur from petroleum naphthas. Petroleum naphthas are heated and sent through a Selective Hydrotreating Unit (SHU) reactor, D-701, to prevent fouling downstream and to treat diolefins. The SHU reactor effluent is routed to a Hydrodesulfurization (HDS) reactor, D-702, to further reduce sulfur content. The HDS reactor effluent is cooled, and the HDS reactor's vapor stream is sent to the amine absorber tower, C-701, to remove H2S from the unreacted hydrogen prior to being recycled within the NHT unit and purged as needed to the hydrogen header system. The HDS reactor's liquid stream is sent to the stabilizer distillation column, C-702, to separate lighter components entrained in the desulfurized naphtha. Additional sulfur is removed from the stabilizer's off-gas at the stabilizer off-gas amine contactor tower, C-703, prior to being recycled to the fuel gas system. Desulfurized naphtha is pumped to the tank fields for gasoline blending. Sulfur containing sour water and amine streams are sent to the SRP. [Section D.46]

- 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 including maintenance vents from petroleum refining process units meeting the criteria of 40 CFR 63, Subpart CC. The Group 1 miscellaneous

process vent emissions from the NHT are routed to the GOHT Flare and associated flare gas recovery system FGRS2.

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 the operating permit), for the emission unit(s) listed above, as specified as follows.

1. 40 CFR 63.640 all except (b) and (s)
2. 40 CFR 63.641
3. 40 CFR 63.642 (a), (b), (c), (d), (e), (f), (g), (i), (k), (m), (n)
4. 40 CFR 63.643 (a), (b), (c), (d)
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), (a)(3), (b), (f), (g), (h), (i), (j)
10. 40 CFR 63.650
11. 40 CFR 63.651
12. 40 CFR 63.654

13. 40 CFR 63.655
14. 40 CFR 63.656
15. 40 CFR 63.657 (a)(1), (b), (c), (d), (f)
16. 40 CFR 63.658
17. 40 CFR 63.660
18. 40 CFR 63.670 (b), (c), (d), (e), (f), (g), (h), (i), (j), (k), (l), (m), (n), (o), (p), (q)
19. 40 CFR 63.671
20. Table 1
21. Table 4
22. Table 5
23. Table 6
24. Table 11
25. Table 12
26. Table 13

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 the operating 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 the operating 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

H.2.5 National Emissions Standards for Storage Vessels (Tanks)—Control Level 2 [40 CFR Part 63, Subpart WW] [326 IAC 20-43] [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 WW, which are incorporated by reference as 326 IAC 20-43 (included as Attachment E.ix to the operating permit), as follows.

1. 40 CFR 63.1060
2. 40 CFR 63.1061
3. 40 CFR 63.1063
4. 40 CFR 63.1065
5. 40 CFR 63.1066 except (a)

H.2.6 National Emissions Standards for Hazardous Air Pollutants for Petroleum Refineries – Miscellaneous Process Vents [40 CFR Part 63, Subpart CC] [326 IAC 20-16]

Pursuant to a Notice of Agency Determination and Order of the Commissioner of the Department of Environmental Management dated June 8, 2017, the Permittee has been granted a one year extension of the August 1, 2017 compliance date for the standards set forth in 40 CFR 63.643(c), 40 CFR 63.655(g)(13), and 40 CFR 63.655(i)(12). Pursuant to Indiana Code § 13-14-2-6 and in order to secure compliance with 40 CFR Part 63.6(i) and 40 CFR 63, Subpart CC, the Permittee is subject to the following order:

1. Within Sixty (60) days of the effective date of the order, the Permittee shall submit a status report with respect to the following milestones indicating the actual dates of the milestones:

   a. The identification of requirements necessary for compliance; and
   b. The projected dates of implementation of necessary compliance measures.

2. The status report in Paragraph 1 shall include a description of the measures that have been or will be implemented in order to comply with the standards set forth in 40 CFR 63.643(c), 40 CFR 63.655(g)(13), and 40 CFR 63.655(i)(12).

3. The Permitee shall comply with the standards set forth in 40 CFR 63.643(c), 40 CFR 63.655(g)(13), and 40 CFR 63.655(i)(12) no later than August 1, 2018.

H.2.7 National Emissions Standards for Hazardous Air Pollutants for Petroleum Refineries – Flares [40 CFR Part 63, Subpart CC] [326 IAC 20-16]

Pursuant to a Notice of Agency Determination and Order of the Commissioner of the Department of Environmental Management dated December 5, 2018, the Permittee has been granted a one year extension of the January 30, 2019 compliance date for the standards set forth in 40 CFR 63.655(i)(9), 63.655(g)(11), 63.670(b), (c), (d), (e), (g), (h), (i), (j), (k), (l), (m), (o), (p), (q), 63.671(a), (b), (c), (d), (e). Pursuant to Indiana Code § 13-14-2-6 and in order to secure compliance with 40 CFR Part 63.6(i) and 40 CFR 63, Subpart CC, the Permittee is subject to the following order:

(a) BP Products North America Inc., Whiting Refinery, Whiting, IN shall install video monitoring equipment and record visible emissions per 40 CFR 63.670(h)(2) for the following flares: South, Alky, DDU, GOHT, 4UF, UIU, VRU, and FCU no later than January 31, 2019.

(b) BP Products North America Inc., Whiting Refinery South, Alky, and DDU flares shall comply with the standards set forth in 40 CFR Part 63, Subpart CC no later than May 1, 2019.

(c) BP Products North America Inc., Whiting Refinery GOHT flare shall comply with the standards set forth in 40 CFR Part 63, Subpart CC no later than July 1, 2019.

(d) BP Products North America Inc., Whiting Refinery 4UF and UIU flares shall comply with the standards set forth in 40 CFR Part 63, Subpart CC no later than October 1, 2019.

(e) BP Products North America Inc., Whiting Refinery VRU and FCU flares shall comply with the standards set forth in 40 CFR Part 63, Subpart CC no later than January 1, 2020.

(f) BP Products North America Inc., Whiting Refinery, Whiting, Indiana shall submit a status report within fifteen (15) days of completion of the following milestones indicating the actual dates of completion.

   (1) The dates by which final compliance with the standards set forth in 40 CFR 63.607(h)(2) for the following flares: South, Alky, DDU, GOHT, 4UF, UIU, VRU and FCU is achieved.

(2) The dates by which final compliance with the standards set forth in 40 CFR Part 63, Subpart CC for South, Alky, and DDU flares is achieved.

(3) The dates by which final compliance with the standards set forth in 40 CFR Part 63, Subpart CC for GOHT flare is achieved.

(4) The dates by which final compliance with the standards set forth in 40 CFR Part 63, Subpart CC for 4UF and UIU flares is achieved.

(5) The dates by which final compliance with the standards set forth in 40 CFR Part 63, Subpart CC for VRU and FCU flares is achieved.

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°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°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 the operating 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), (a)(5), (a)(6), (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 32
53. Table 33
54. Table 34
55. Table 35
56. Table 36
57. Table 37
58. Table 38
59. Table 39
60. Table 40
61. Table 41
62. Table 42
63. Table 43
64. Table 44

H.3.3 Compliance Monitoring Requirements for the Fluidized Catalytic Cracking Unit (FCU) 500 and Fluidized Catalytic Cracking Unit (FCU) 600 [326 IAC 20-50] [40 CFR 63, Subpart UUU]

To demonstrate the compliance status with Condition H.3.2 and as approved by the U.S. EPA on April 3, 2017, the Permittee shall comply with the following alternative compliance monitoring requirements for the Fluidized Catalytic Cracking Unit (FCU) 500 and Fluidized Catalytic Cracking Unit (FCU) 600:

During periods of startup, shutdown, and hot standby the Permittee shall maintain the oxygen concentration in the exhaust gas of each of the two FCCUs (FCU500 and FCU600) at or above 1% by volume on a wet basis.

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 the operating 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 Linde 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:

(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 equal to or less than five hundred thousand (500,000) British thermal units per hour except where total capacity of equipment operated by one (1) stationary source as defined in 326 IAC 2-7-1(39) exceeds two million (2,000,000) British thermal units per hour.[326 IAC 2-7-1(21)(J)(i)(BB)] [40 CFR 60, Subpart IIII] [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ] [Section A]

(y) Activities associated with emergencies, as follows:

(2) Emergency generators as follows: [326 IAC 2-7-1(21)(J)(xxii)(BB)]

(A) Gasoline generators not exceeding one hundred ten (110) horsepower; [326 IAC 2-7-1(21)(J)(xxii)(BB)(aa)] [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

(B) Diesel Generators not exceeding one thousand six hundred (1,600) horsepower. [326 IAC 2-7-1(21)(J)(xxii)(BB)(bb)] [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ]

(C) Natural gas turbines or reciprocating engines not exceeding sixteen thousand (16,000) horsepower. [326 IAC 2-7-1(21)(J)(xxii)(BB)(cc)] [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

(3) Stationary fire pump engines. [326 IAC 2-7-1(21)(J)(xxii)(CC)] [40 CFR 60, Subpart IIII] [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

(ee) Diesel-fired pump engines, as follows:

(1) One (1) emergency fire pump engine, identified as Firepump Engine 1 (PU-300B), a 2010 model year engine permitted and installed in 2012, with a maximum capacity of 359 HP. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ]

(2) Two (2) non-emergency pump engines, identified as Pump Engine 2 (P-31) and Pump Engine 3 (P-32), 2010 model year engines permitted and installed in 2012, each with a maximum capacity of 460 HP. [40 CFR 60, Subpart IIII] [40 CFR 63, Subpart ZZZZ]

(ii) Two (2) propane-fired emergency generator engines, identified as Radio Tower Emergency Engine 1 and Radio Tower Emergency Engine 2, permitted in 2019, each with a maximum capacity of 230 HP. [40 CFR 60, Subpart JJJJ] [40 CFR 63, Subpart ZZZZ]

(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 the operating 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. As part of the WEP, there will be new control valves, instrumentation upgrades (valves, flanges) and new piping connections (valves, flanges). 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. As part of the WEP, there are removal of hydraulic constraints (pump modification) and new piping connections (valves and flanges). 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 Linde 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.

(pp) The Naphtha Hydrotreater (NHT), identified as Unit ID 810, approved in 2016 for construction, removes sulfur from petroleum naphthas. Petroleum naphthas are heated and sent through a Selective Hydrotreating Unit (SHU) reactor, D-701, to prevent fouling downstream and to treat diolefins. The SHU reactor effluent is routed to a Hydrodesulfurization (HDS) reactor, D-702, to further reduce sulfur content. The HDS reactor effluent is cooled, and the HDS reactor's vapor stream is sent to the amine absorber tower, C-701, to remove H2S from the unreacted hydrogen prior to being recycled within the NHT unit and purged as needed to the hydrogen header system. The HDS reactor's liquid stream is sent to the stabilizer distillation column, C-702, to separate lighter components entrained in the desulfurized naphtha. Additional sulfur is removed from the stabilizer's off-gas at the stabilizer off-gas amine contactor tower, C-703, prior to being recycled to the fuel gas system. Desulfurized naphtha is pumped to the tank fields for gasoline blending. Sulfur containing sour water and amine streams are sent to the SRP. [Section D.46]

- F-701 HDS Reactor Heater

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 the operating 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 Linde 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 the operating 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**) daytime 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: ____________________

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:	

Page 2 of 2

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: ____

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

☐ No deviation occurred in this quarter.
☐ Deviation/s occurred in this quarter.
Deviation has been reported on: ____________________

Submitted by: ____

Title / Position: ____

Signature: ____

Date: ____

Phone: ____

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for a Part 70 Significant Permit Modification

Source Description and Location

Source Name:	**BP Products North America, Inc. - Whiting Business Unit**
Source Location:	**2815 Indianapolis Boulevard, Whiting, Indiana 46394**
County:	**Lake (North Township)**
SIC Code:	**2911 (Petroleum Refining)**
Operation Permit No.:	**T 089-30396-00453**
Operation Permit Issuance Date:	**January 1, 2015**
Significant Permit Modification No.:	**089-45450-00453**
Permit Reviewer:	**Aasim Noveer**

Source Definition

(a) This stationary source, the Whiting Business Unit (Plant ID 089-00453), consists of a single plant:

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

The stationary source formerly included one other plant:

(2) The Marketing Terminal (previously designated 089-00004), located at 2530 Indianapolis Boulevard, Whiting, Indiana 46394. The Marketing Terminal was permanently decommissioned and removed from the source in Minor Source Modification No. 089-42309-00453, issued on July 21, 2020.

The source determination also formerly considered one other plant:

(3) INEOS USA LLC (designated as 089-00076), 2357 Standard Avenue, Whiting, IN 46394. Significant Source Modification No. 089-22011-00076, issued on March 20, 2006, withdrew an earlier determination that the source then owned by INEOS USA, LLC was part of the BP Products North America - Whiting Business Unit (Plant ID 089-00453) source. The 2006 determination was based on a sale of shares that eliminated any common ownership of the two sources. INEOS USA LLC ceased operation and its Part 70 Operating Permit No. 089-31963-00076 was revoked in Revocation No. 089-35599-00076, issued on March 25, 2015.

(b) The BP Whiting Refinery (BP) needs high pressure steam and high pressure hydrogen for its Whiting Refinery Modernization Project (WRMP). Linde Inc. owns and operates a plant near the BP facility (2551 Dickey Rd., East Chicago, IN 46312) that produces low pressure hydrogen, carbon dioxide and low pressure steam (Plant A, Plant ID 089-00435, Linde's unit identification SMR1, SMR2, SMR3, and SMR4). Linde'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, Linde constructed a new plant (Plant B, identified as HU-1 and HU-2 in the BP permit) near Plant A and sharing the same physical address. IDEM, OAQ examined whether Linde's Plant B is part of the same major source as Linde's Plant A, and whether one or both of the Linde 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 Linde Plants

The first analysis will be of the relationship between the two Linde plants. The Linde plants are owned by Linde. 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 Linde 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 Linde 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. Linde's Plant B is located approximately 75 yards from Linde's Plant A. The plants are separated by property owned by Mittal Steel. A Mittal Steel bridge runs between the two Linde 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.

Linde 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. Linde has stated that it will not operate Plant B if the WRMP were to cease operation. Linde 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 Linde 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 plants. Linde uses the same plant manager for other Linde sources that are in the same general area, even when the sources are miles apart. Linde employs additional regional employees with offices at Plant B that have responsibilities at Plant A, Plant B and two other regional Linde plants in Michigan. Linde hired additional employees to operate Plant B. All Linde 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 Linde plants in the region and elsewhere. Linde 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 has its own control room, supply room, parts room and functions as a stand-alone plant. The production process is not split in any way between the two Linde plants. The raw materials Plant B uses to produce hydrogen and high pressure steam, natural gas, refinery gas and water, come directly from BP.

The two Linde plants do not operate as a single source. Though the plants 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 Linde plants are not part of the same major source.

The Linde Plants and the BP Whiting Refinery

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

The Linde 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 dedicates at least 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 supplies all of the natural gas, refinery gas and water used by Plant B. BP has 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 flow through lines from BP to Plant B. Plant B uses that fuel and raw material to create high pressure steam and hydrogen which is 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 Renewal No. T089-30396-00453 effective on January 1, 2015. The source has since received the following approval:

Permit Type	Permit Number	Issuance Date
Administrative Amendment	089-35450-00453	February 19, 2015
Significant Source Modification	089-35708-00453	August 28, 2015
Significant Permit Modification	089-35729-00453	September 16, 2015
Significant Source Modification	089-36651-00453	May 26, 2016
Significant Permit Modification	089-36656-00453	June 14, 2016
Administrative Amendment	089-36920-00453	June 15, 2016
Minor Source Modification	089-37370-00453	October 28,2016
Significant Permit Modification	089-37390-00453	December 28, 2016
Administrative Amendment	089-38381-00453	May 15, 2017
Significant Permit Modification	089-38641-00453	October 4, 2017
Significant Source Modification	089-38851-00453	January 11, 2018
Significant Permit Modification	089-38868-00453	January 29, 2018
Minor Source Modification	089-39950-00453	June 27, 2018
Minor Permit Modification	089-39973-00453	August 27, 2018
Administrative Amendment	089-40242-00453	September 12, 2018
Significant Permit Modification	089-40517-00453	September 20, 2019
Minor Source Modification	089-42309-00453	July 21, 2020
Minor Permit Modification	089-42328-00453	September 9, 2020
Significant Permit Modification	089-43173-00453	June 2, 2021
Significant Source Modification	089-42988-00453	July 20, 2021
Significant Permit Modification	089-42998-00453	August 5, 2021
Minor Source Modification	089-44288-00453	October 13, 2021
Significant Permit Modification	089-44305-00453	December 9, 2021

The source submitted an application for a Part 70 Operating Permit Renewal on April 1, 2019. At this time, the application is under review.

County Attainment Status

The source is located in Lake County, North Township.

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	Attainment effective May 20, 2022, for the 2008 8-hour ozone standard.
O_3	Moderate nonattainment effective November 7, 2022, for the 2015 8-hour ozone standard for Calumet Township, Hobart Township, North Township, Ross Township, and St. John Township. Unclassifiable or attainment effective August 3, 2018, for the 2015 8-hour ozone standard for the remainder of the county.
$PM_{2.5}$	Unclassifiable or attainment effective January 28, 2019, for the 2012 annual $PM_{2.5}$ standard.
$PM_{2.5}$	Unclassifiable or attainment effective December 13, 2009, for the 2006 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	Unclassifiable or attainment effective January 29, 2012, for the 2010 NO_2 standard.
Pb	Unclassifiable or attainment effective December 31, 2011, for the 2008 lead standard.

(a) Ozone Standards
U.S. EPA, in the Federal Register Notice 87 FR 60897 dated October 7, 2022, designated Lake County, North Township, as moderate nonattainment for the 2015 8-hour ozone standard effective November 7, 2022. On December 15, 2022, the Environmental Rules Board issued an emergency rule adopting the U.S. EPA's designation. Volatile organic compounds (VOC) and Nitrogen Oxides (NOx) are regulated under the Clean Air Act (CAA) for the purposes of attaining and maintaining the National Ambient Air Quality Standards (NAAQS) for ozone. Therefore, VOC and NOx emissions are considered when evaluating the rule applicability relating to ozone. Therefore, VOC and NOx 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 the 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 (1) of the twenty-eight (28) listed source categories, as specified in 326 IAC 2-2-1(ff)(1), 326 IAC 2-3-2(g), or 326 IAC 2-7-1(22)(B). Therefore, fugitive emissions are counted toward the determination of PSD, Emission Offset, and Part 70 Permit applicability.

The fugitive emissions of hazardous air pollutants (HAP) are counted toward the determination of Part 70 Permit applicability and source status under Section 112 of the Clean Air Act (CAA).

Greenhouse Gas (GHG) Emissions

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 GHG emissions to determine operating permit applicability or PSD applicability to a source or modification.

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. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	Source-Wide Emissions Prior to Modification (ton/year)								
	PM[1]	PM_{10}[1]	$PM_{2.5}$[1, 2]	SO_2	NO_X	VOC	CO	Single HAP[3]	Combined HAPs
Total PTE of Entire Source Including Fugitives*	>100	>100	>100	>100	>50	>50	>100	>10	>25
Title V Major Source Thresholds	NA	100	100	100	50	50	100	10	25
PSD Major Source Thresholds	100	100	100	100	100	100	100	--	--
Emission Offset Major Source Thresholds	---	NA	NA	NA	50	50	NA	--	--

[1]Under the Part 70 Permit program (40 CFR 70), PM_{10} and $PM_{2.5}$, not particulate matter (PM), are each considered as a "regulated air pollutant."
[2]$PM_{2.5}$ listed is direct $PM_{2.5}$.
[3]Single highest source-wide HAP
*Fugitive HAP emissions are always included in the source-wide emissions.

(a) This existing source is a major stationary source, under PSD (326 IAC 2-2), because the PSD regulated pollutant(s), PM, PM_{10}, $PM_{2.5}$, SO_2 and CO are emitted at a rate of 100 tons per year or more, each, 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 NOx and VOC, nonattainment regulated pollutants, are emitted at a rate of 50 tons per year or more, each.

(c) This existing source is a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions are equal to or greater than ten (10) tons per year for a single HAP and equal to or greater than twenty-five (25) tons per year for a combination of HAPs.

(d) These emissions are based on the TSD of Significant Permit Modification No. 089-42998-00453, issued on August 5, 2021.

Description of Proposed Modification

The Office of Air Quality (OAQ) has reviewed an application, submitted by BP Products North America, Inc. - Whiting Business Unit on May 23, 2022, relating to addressing the two claims granted by the EPA as follows:

On March 4, 2022, the EPA Administrator issued a response order partially granting and partially denying the Petition for Objection (Petition No. V-2021-9) filed by the Environmental Integrity Project and Sierra Club on the BP Products North America, Inc. Whiting Business Unit significant title V permit modification (SPM No. 089-43173-00453, issued on June 2, 2021). Four claims were raised in the petition, these claims and EPA's responses are summarized as follows:

Claim A alleged that the permit modification fails to assure compliance with a SIP limit, which applies to all PM10 emissions from each boiler stack. EPA denied Claim A on the basis that the permit modification didn't change the permit condition, and the petition is limited to the significant permit modification.

Claim B alleged that the 494.99 ton/year rolling PM10 limit is based on maximum firing rates that cannot be achieved in practice. EPA denied Claim B on the basis that the petitioner did not address how this claim impacts the applicable requirements or associated compliance provisions.

Claim C alleged that the emission rates (*i.e., emission factors*) used to quantify PM10 emissions from the boilers are flawed and understate actual emissions by up to 25%. EPA granted Claim C on the basis that the permit and permit record do not ensure that heat input will be calculated the same way when reporting monthly heat input from the boilers and duct burners as it was when establishing the stack test-based emission factors.

Claim D alleged that the permit fails to establish testing, monitoring, or reporting requirements adequate to determine or assure compliance with the ton/year rolling PM10 limit. EPA granted Claim D on the basis that the petitioners demonstrated that stack test frequency and PM10 emissions variability from the boilers, duct burners, and selective catalytic reduction devices are not sufficient to assure compliance.

The Petition No. V-2021-9 (2022 Order Granting in Part and Denying in Part in a Petition for Object to Title V Operating Permit for BP Whiting) can be found on the U.S. EPA website by searching for the "Title V Petition Database."

There is no change in the source's permitted total emissions as a result of this proposed modification or in its potential to emit. The source has requested to make changes in the compliance section and in the methodology for calculating its emissions.

Proposed Permit Revision Addressing EPA Order Regarding Claim C of the Petition for Objection

The existing Permit Condition D.02.1(a) imposes combined particulate matter (PM) and particulate matter less than ten microns (PM10) limits across five sets of emissions units at the Whiting Refinery: (a) TGU A and TGU B; (b) FCU 500; (c) FCU 600; (d) the SCR systems on the five 3SPS Boilers; and (e) the duct burners on the five 3SPS Boilers. In order to demonstrate compliance with the combined PM and PM10 12-month rolling limits, the Permit requires the Whiting Refinery to total the emissions from these emission units on a monthly basis.

The EPA Order specifically addressed the calculation of (d) and (e) above: i.e., the PM and PM10 emissions from the SCR systems and duct burners on the five 3SPS Boilers. The Permit currently requires that these emissions be determined by multiplying the PM and PM10 emission rates(1) of each SCR system and duct burner (in lbs/MMBtu) by the monthly heat input to the 3SPS Boilers and duct

1 Emission rates are determined by the most recent valid stack tests in lb PM/MMbtu or lb PM10/MMBtu.

burners (in total MMBtu), respectively. This calculation provides the total pounds of PM and PM10 emitted per month for each of the 3SPS SCR systems and duct burners. The total monthly emissions are added to the emissions from the prior eleven (11) months to determine the twelve (12) month rolling average. Finally, these totals are then added to the total emissions of PM and PM10 from the other emission units limited by Condition D.02.1 and compared against the limits of 796.66 tons per twelve (12) consecutive month period and 494.99 tons per twelve (12) consecutive month period, respectively, to determine compliance with the Title V Permit.

The “proposed changes” section below maintains the general formula that determines the contribution of the 3SPS SCR systems and duct burners to the D.02.1(a) PM and PM10 emission limits (i.e., PM and PM10 emission rate of each unit monthly heat input of each unit). However, to address the EPA Order, the “proposed changes” section requires that, following issuance of the proposed permit modification, the Whiting Refinery will determine the monthly heat input for this general compliance formula by using the higher heating value (HHV) of the refinery fuel gas combusted by the 3SPS Boilers and duct burners determined with gas chromatography (GC) technology. The “proposed changes” section explains this will be accomplished by a new Condition D.02.2(k) that specifies the formula used to calculate heat input using the HHV of the refinery fuel gas. The new Condition D.02.2(k) also requires the Whiting Refinery to continuously analyze the HHV of the refinery fuel gas and continuously measure and record the fuel flow to the 3SPS Boilers and duct burners. The Permit already requires the Whiting Refinery to collect the data (fuel flow to the units and HHV) necessary to compute the heat input for the 3SPS Boilers and duct burners in this manner. See, e.g., Condition D.24.4(a)(2) and (3) imposing annual heat input limits on the 3SPS Boilers and duct burners.

Because the monthly heat input for determining the 3SPS SCR systems and duct burners contribution toward the combined PM and PM10 emission limits is based on the HHV of the refinery fuel gas, the “proposed changes” section requires that the PM and PM10 emission rates (lbs/MMBtu) used to calculate the 3SPS SCR systems and duct burners contribution toward the combined limits also will be based on heat input (MMBtus) determined using the HHV of the refinery fuel gas. See proposed Condition D.02.2(d) and (i) (defining the emission rates (R) for the 3SPS Stacks and 3SPS Boilers). The proposed change section also includes an update that the lb/MMBtu emission rates will be based on the “heat input calculated in accordance with proposed Condition D.02.2 (k).” The proposed changes section also contains revised emission rates in Condition D.02.2(d)’s summary table of the most recent PM emission rates for each of the 3SPS Stacks (RPM-j) using the HHV of the refinery fuel gas, where those rates previously were calculated and incorporated into the existing Permit using the fuel factor (F-Factor). See Appendix D containing the HHV based calculations. Finally, the proposed changes section requires continuous pressure and temperature monitoring of the fuel flow meters.

Proposed Permit Revision Addressing EPA Order Regarding Claim D of the Petition for Objection

Every month, the existing Permit Condition D.02.4(a) requires the Whiting Refinery to calculate the PM10 emissions from the 3SPS SCR systems and duct burners by multiplying their PM10 emission rates established during the most recent stack test (in lbs/MMbtu) by the continuously monitored heat input (or firing rate) (in MMBtus). This calculation demonstrates the 3SPS SCR system and duct burner contribution to the rolling 12-month rolling PM10 emission limit set in Condition D.02.1(a). Further, pursuant to Condition D.02.5 and D.24.15(d) the Whiting Refinery provides publicly available quarterly reports to IDEM that identify these monthly firing rates for the 3SPS Boilers and duct burners and the calculated PM10 emissions showing compliance with D.02.1(a).

Permit Condition C.9 specifies the methods[2] the Whiting Refinery uses to measure the emission rates of the five 3SPS Stacks and 3SPS Boilers. And Condition D.02.3(a) requires the Whiting Refinery to conduct valid stack testing to establish the PM10 emission rates for the five 3SPS Stacks and their

2 Consent Decree (Civil No. 2:12-CV-00207) specified the test methodology to be used for FCU 500 and 600.

associated Boilers so that, (1) each of the five is tested at least once every five years, and (2) at least one of the five is tested each year (among other additional testing obligations).

The EPA Order stated that under the specific circumstances characterized by EPA in its Order, “the Permit’s reliance on a PM10 emission factor (for the 3SPS Boilers, SCR systems, and duct burners) based on stack tests spaced five (or even two-and-a-half) years apart is not sufficient to account for their contributions towards assuring compliance with the 494.99 tons PM10 limit.” EPA Order at 22. EPA gave IDEM wide discretion to address the identified concern suggesting “various options that will better account for the variability of PM_{10} emissions from the 3SPS boilers, duct burners, and SCRs, and the operating parameters that contribute to these emissions. For example, IDEM may require monitoring of ammonia injection rates and establishing correlations between these (or other parameters) and PM_{10} emissions.”

Two substantive modifications to the Permit have been made to address the EPA Order. The first is use of a demonstrated quantifiable correlation as a reasonable predictor of condensible particulate matter (CPM) measured by Method 202 from the 3SPS Stacks along with an additional safety factor that guarantees a maximized calculation of each 3SPS Stack's contribution to the PM10 imit. The second is the addition of performance testing conditions defined in accordance with 326 IAC 3-6-3’s requirement to measure worst-case emissions. The proposed permit modifications are supported by reasoned factual bases and provide the appropriate supplemental monitoring requested by EPA to satisfy Title V’s requirement to demonstrate continuous compliance with applicable requirements.

In proposing the first modification, establishing a CPM correlation, the results of the PM/PM_{10} performance tests conducted on the 3SPS Stacks since 2015 were examined, including review of ammonia injection and fuel gas sulfur content during these tests. See Application, Appendix D. Analysis of all five 3SPS Stacks’ test results identified a discernable – and most importantly, quantifiable – correlation between the sulfur content of fuel combusted during the stack tests and the CPM measured during the stack tests. See Application, Appendix D.

From this data, a linear regression was developed that provides a formula to predict CPM emission rates (in lb/MMBtu) as would be measured by a Method 202 performance test based on a known value of fuel gas sulfur content combusted by the 3SPS Boilers and duct burners. See Appendix D. This formula, along with a new table of the data used to derive the slope and Y-intercept of the formula, appears in the redline at revised Condition D.02.2(i). The revised Condition also identifies the slope and Y-intercept values for this formula based on the stack test data listed in the new table.

Incorporation of the new formula into the Permit responds to and remedies the EPA’s charge that the Permit’s up-to-5-year-old stack test data (that determined the emission rates used to calculate each 3SPS SCR system and duct burner’s monthly contribution to the D.02.1(a) PM_{10} emission limit) is not necessarily representative of actual PM_{10} emissions. The new formula will allow the source to convert the Permit’s single, static PM_{10} emission rate (R_{PM10-j}) into emission rates of PM_{10}’s component parts: filterable PM_{10} (FPM) and CPM. Instead of the previous emission rate that was re-established as infrequently as every five years, the source will use the separate component emission rates (of FPM and CPM) to calculate monthly emissions from the 3SPS Stacks that are based on the actual operating conditions. The stack test results in Appendix D indicate a quantifiable correlation between fuel gas sulfur content and CPM; however, the FPM measured during a stack test does not show the same correlation.[3]

Therefore, while the emission rates for FPM (R_{PM-j}) will continue to be set by (and remain unchanged from) the most recent stack test results from the 3SPS Stacks, the emission rates for CPM (R_{CPM-j}) from the 3SPS SCR systems and duct burners will depend on actual fuel gas sulfur content each month. Using the linear regression formula in the revised Permit, the 3SPS SCR systems and duct burner contributions to the D.02.1(a) PM_{10} emission limit may increase or decrease each month based on the measured monthly average sulfur content of the refinery fuel gas. The updated compliance formula for the 3SPS SCR systems and duct burners relies on no fewer than eleven stack tests (versus a single stack test) to

[3] It is also worth noting that, historically, CPM makes up the largest portion of PM_{10}; FPM makes up a smaller portion of PM_{10} measured during testing of the 3SPS Stacks.

establish the emission rates used to calculate their contribution to the combined PM_{10} emissions limit. This makes the reported emissions under the proposed permit modification more responsive to fluctuating fuel gas sulfur content than reported under the existing Permit's requirements.

The Permit has also been updated to include new monitoring, reporting, and recordkeeping conditions in Section D.02 to support use of the new formula to calculate the 3SPS SCR systems and duct burners' monthly emissions. These additional requirements create multiple timely touchpoints to monitor both the units' operation and assure compliance with the relevant applicable requirements.

In the second modification, defining stack test conditions for PM_{10} at the 3SPS Stacks, the source will be required to conduct future PM and PM_{10} testing of the 3SPS Stacks to maximize the CPM measured by Method 202 during testing. A new subpart in Condition D.02.3(a) would require that the 3SPS Stacks' performance tests be conducted using an ammonia injection rate that is no less than the maximum of the average monthly injection rate for the 3SPS SCR system associated with the 3SPS Stack being tested over the previous 5 years. The source utilizes the SCR system to control the 3SPS Boilers' nitrous oxide (NOx) emissions in accordance with its consent decree obligations. To maintain properly functioning SCR systems, the source (already) must monitor and record the ammonia injection rate to the SCR systems to assure optimum control of the 3SPS Stacks' NOx emissions. However, certain operating scenarios may result in an increase in ammonia injection above normal ranges (e.g., to overcompensate for catalyst that may be at the end of its useful life and in need of replacement) during periods where the SCR is not operating optimally, or to proactively reduce NOx emissions. Ammonia from the 3SPS Stacks that does not react with NOx can be a contributor to Method 202 CPM measurements when sulfur combustion compounds are present. Therefore, the revised permit's new stack test condition includes a minimum total ammonia injection rate to assure that CPM measured during these tests and used to establish the R_{PM10-j} emission rate does not underestimate Method 202 measured CPM. Utilizing the maximum of the average monthly total ammonia injection from the past five years assures that any swings in ammonia injection rate due to relatively rare operational necessity (e.g., end of life catalyst operation) are accounted for when establishing the total ammonia injection rate for a valid test. In addition, existing Preventive Maintenance Plan requirements have been incorporated into the Permit to maintain and test the SCR catalyst during each planned unit outage and must be completed every 3 years at minimum. This all but eliminates the likelihood of an already rare, elevated ammonia injection operational scenario occurring undetected resulting in an emissions rate above that established during stack testing. As a final measure to ensure calculated monthly emissions from the 3SPS Stacks use a maximum emission rate to avoid underestimating actual emissions, once a boiler and duct burner has been tested under these new ammonia injection requirements a safety factor of 1.3 will be applied to the emission calculations each month if the monthly average ammonia injection for that month is higher than the average ammonia injection from the most recent test. A 1.3 safety factor was selected as it represents the average standard deviation (i.e., ~ 30%) from the measured CPM for the tests included in the linear regression analysis. Utilization of a safety factor also further aligns with EPA's direction to IDEM; "Additionally or alternatively, IDEM may also consider establishing a reasonably conservative safety factor on the lb/MMBtu emission factor derived from the stack tests."

Additionally, when developing the linear regression that models the expected CPM emissions from the 3SPS Stacks based on average monthly sulfur content of the fuel gas, the correlation was less strong (more erratic) during stack tests when the ratio of average injection rate of ammonia versus the average total sulfur content of the fuel[4] combusted was less than two. *See* Appendix D. Accordingly, the linear regression excludes past test data where the ratio was less than two.[5] The relationship between fuel gas sulfur content and ammonia injection is consistent with the general understanding of CPM Method 202 measurement in units controlled by SCR systems. The chemistry that occurs between the compounds in the 3SPS Stacks suggests that – depending on the ratio of these two molecules (sulfur or ammonia) – one or the other will be the controlling/limiting agent to the measurement of Method 202 CPM.

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[4] Measured in parts per million (ppm)

[5] The October 21, 2015 and November 1, 2016 tests were not included in the linear regression analysis as the ratio of ammonia injection in pounds per hour to total sulfur in ppm was less than two.

By requiring valid test data to have a ratio of ammonia injection rate to fuel gas sulfur of at least two, the developed correlation is validated and ensures that the ammonia component of the stack gases is not the limiting aspect of expected CPM measurement during testing. Accordingly, imposing this additional requirement on “valid” PM_{10} stack tests under the revised Permit helps ensure that the stack testing is conducted under circumstances expected to generate “worst case” CPM Method 202 measurement for the 3SPS Stacks at any given sulfur content. 326 IAC 3-6-3.

It is important to note that the revised permit does not require that the source maintain a ratio of ammonia injection rate to fuel gas sulfur of at least two during normal operations of the 3SPS SCR systems. The ratio requirement during testing is intended to maximize the Method 202 CPM measurement during testing; however, during normal operations the source intends only to inject the needed amount of ammonia for the SCR systems to adequately control NOx emissions. Therefore, the linear regression formula will likely conservatively overstate the Method 202 CPM formation, assuring buffered compliance of the 3SPS SCR systems and duct burners contribution to the 12-Month D.02.1(a) PM_{10} Limit as compared to their actual emissions.

Accordingly, the proposed changes section includes definitions of the emission rates in Conditions D.02.2(d) and (i), a new Condition D.02.3(a)(5) creating conditions for what constitutes a “valid” PM10 stack test of the 3SPS Stacks and 3SPS Boilers, and conforming revisions to the monitoring, record keeping, and reporting conditions in D.02.4 and D.02.5. Specifically, the permit has been modified to do the following, as described in the Proposed Changes section below:

1. Adjust the Permit’s required calculation of the monthly PM10 emissions from the 3SPS SCR systems and duct burners based on the actual monthly average of the sulfur content of refinery fuel gas combusted by the 3SPS Boilers and duct burners. To accomplish this, the proposed revision includes new conditions that:

    a. Develop a formula that correlates the sulfur content of combusted refinery fuel gas with the condensable PM10 (CPM) emissions measured at the 3SPS Stacks and Boilers during EPA Method 202 stack tests.

    b. Require monitoring, record keeping, and reporting on the sulfur content of the refinery fuel gas combusted by the 3SPS Boilers and duct burners.

    c. Require updates to the formula upon submittal of new (valid) stack test results.

    d. Require application of a conditional 30% safety factor to the monthly emission calculation if the measured ammonia injection is less than the ammonia injection rate during the prior test.

2. Conduct PM10 stack tests of the 3SPS Stacks to ensure that the PM10 measurement provides a conservative accounting of potential CPM formed by ammonia/sulfur combustion species reaction in Method 202 and supports the sulfur content adjustment identified in (1), above.
To accomplish these objectives, the Whiting Refinery will:

    a. Rely only on PM10 emission rates obtained from stack tests of the 3SPS Stacks where the ammonia injection rate to the SCR system for the Stack is no less than its average hourly injection rate for the 12-months prior to the stack test, and monitor, record, and report on the 3SPS SCR systems’ ammonia injection rates accordingly.

    b. Rely only on PM10 emission rates obtained from stack tests of the 3SPS Stacks where the ammonia injection rate to the SCR system is not the limiting (controlling) element of condensable particulate formation.

    c. When the hourly ammonia injection rate during the testing is less than the highest monthly average ammonia injection rate since the last valid compliance demonstration, the automated system will be overridden, and the ammonia injection rate will be at the higher rate.

Enforcement Issues

There are no pending enforcement actions related to this modification.

Emission Calculations

See Appendix A of this Technical Support Document for detailed emission calculations.

Permit Level Determination – Part 70 Modification to an Existing Source

There are no new emission units or modifications to existing emission units (i.e., no physical change or change in the method of operation occurring at the source) as a result of this modification. See the "Description of Proposed Modification " section above for more detail.

Pursuant to 326 IAC 2-1.1-1(12), Potential to Emit is defined as "the maximum capacity of a stationary source or emission unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, IDEM, or the appropriate local air pollution control agency."

There is no change in the potential to emit of this source due to this modification.

Pursuant to 326 IAC 2-7-12(d)(1), this change to the permit is being made through a Significant Permit Modification because this modification makes a significant change to existing monitoring conditions.

Permit Level Determination – PSD and Emission Offset

(a) There is no physical change or change in the method of operation occurring at the source as a result of this modification and there are no increases of regulated NSR pollutants.

PTE of the Entire Source After Issuance of the Part 70 Modification

The table below summarizes the after issuance source-wide potential to emit, reflecting all limits, of the emission units. Any control equipment is considered federally enforceable only after issuance of the Part 70 source and/or permit modification, and only to the extent that the effect of the control equipment is made practically enforceable in the permit. If the control equipment has been determined to be integral, the table reflects the potential to emit (PTE) after consideration of the integral control device.

	Source-Wide Emissions After Issuance (ton/year)								
	PM[1]	PM_{10}[1]	$PM_{2.5}$[1, 2]	SO_2	NO_X	VOC	CO	Single HAP[3]	Combined HAPs
Total PTE of Entire Source Including Fugitives*	>100	>100	>100	>100	>50	>50	>100	>10	>25
Title V Major Source Thresholds	NA	100	100	100	50	50	100	10	25
PSD Major Source Thresholds	100	100	100	100	100	100	100	--	--
Emission Offset Major Source Thresholds	---	NA	NA	NA	50	50	NA	--	--

	Source-Wide Emissions After Issuance (ton/year)								
	PM[1]	PM_{10}[1]	$PM_{2.5}$[1, 2]	SO_2	NO_X	VOC	CO	Single HAP[3]	Combined HAPs
[1]Under the Part 70 Permit program (40 CFR 70), PM_{10} and $PM_{2.5}$, not particulate matter (PM), are each considered as a "regulated air pollutant." [2]$PM_{2.5}$ listed is direct $PM_{2.5}$. [3]Single highest source-wide HAP *Fugitive HAP emissions are always included in the source-wide emissions.									

(a) This existing major PSD stationary source will continue to be major under 326 IAC 2-2 because at least one pollutant PM, PM10, PM2.5, SO2 and CO, has emissions equal to or greater than the PSD major source threshold.

(b) This existing major Emission Offset stationary source will continue to be major under 326 IAC 2-3 because the emissions of the nonattainment pollutant(s), NOx and VOC, will continue to be equal to or greater than the Emission Offset major source thresholds.

(c) This existing major source of HAP will continue to be a major source of HAP, as defined in 40 CFR 63.2, because HAP emissions will continue to be equal to or greater than ten (10) tons per year for any single HAP and/or equal to or greater than twenty-five (25) tons per year of a combination of HAPs. Therefore, this source is a major source under Section 112 of the Clean Air Act (CAA).

Federal Rule Applicability Determination

Due to the modification at this source, federal rule applicability has been reviewed as follows:

New Source Performance Standards (NSPS):

(a) There are no New Source Performance Standards (NSPS) (326 IAC 12 and 40 CFR Part 60) included in the permit for this proposed modification.

National Emission Standards for Hazardous Air Pollutants (NESHAP):

(b) There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) (40 CFR Part 63, 326 IAC 14, and 326 IAC 20) included in the permit for this proposed modification.

Compliance Assurance Monitoring (CAM):

(a) Pursuant to 40 CFR 64.2, Compliance Assurance Monitoring (CAM) is applicable to each pollutant-specific emission unit that meets the following criteria:

(1) has a potential to emit before controls equal to or greater than the major source threshold for the regulated pollutant involved;

(2) is subject to an emission limitation or standard for that pollutant (or a surrogate thereof); and

(3) uses a control device, as defined in 40 CFR 64.1, to comply with that emission limitation or standard.

(b) Pursuant to 40 CFR 64.2(b)(1)(i), emission limitations or standards proposed after November 15, 1990, pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act are exempt from the requirements of CAM. Therefore, an evaluation was not conducted for any emission limitations or standards proposed after November 15, 1990, pursuant to a NSPS or NESHAP under Section 111 or 112 of the Clean Air Act.

(c) Pursuant to 40 CFR 64.3(d), if a continuous emission monitoring system (CEMS) is required pursuant to other federal or state authority, the owner or operator shall use the CEMS to satisfy the requirements of CAM according to the criteria contained in 40 CFR 64.3(d).

Based on this evaluation, the requirements of 40 CFR Part 64, CAM, are not applicable to this modification because there are no new pollutant-specific emissions units meeting the criteria above and no change to the potential to emit of any existing emissions units.

State Rule Applicability

There is no change in the state rule applicability due to this modification.

Compliance Determination and Monitoring Requirements

Permits issued under 326 IAC 2-7 are required to assure 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.

Condition D.02.2 - Compliance Determination Requirements, contains the objected equations. Please see the “Proposed Changes” section of this document for detailed informing regarding revisions made to these equations.

(a) The Compliance Determination Requirements applicable to this modification are as follows:

Testing Requirements:

Summary of Testing Requirements

Emission Unit	Control Device	Timeframe for Testing or Date of Initial Valid Demonstration)	Pollutant/ Parameter	Frequency of Testing	Authority
Boiler #31 and Duct Burner #31 (stack 503-01)		11/16/2021[2]			
Boiler #32 and Duct Burner #32 (stack 503-02)		10/9/2018[2]			
Boiler #33 and Duct Burner #33 (stack 503-03)	none[1]	10/11/2018[2]	PM, PM_{10}	every 5 years[3]	326 IAC 2-2
Boiler #34 and Duct Burner #34 (stack 503-04)		10/12/2018[2]			
Boiler #36 and Duct Burner #36 (stack 503-05)		4/16/2019[2]			
Boiler #31 (stack 503-01)		11/16/2021[2]			
Boiler #32 (stack 503-02)		180 days[4]			
Boiler #33 (stack 503-03)	none[1]	180 days[4]	PM, PM_{10}	every 5 years[5]	326 IAC 2-2
Boiler #34 (stack 503-04)		180 days[4]			
Boiler #36 (stack 503-05)		180 days[4]			

Notes:

1. *Units do not have control devices for particulate matter that is the subject of these testing requirements.*

2. *One (1) boiler and duct burner combination shall be tested not later than 180 days after the issuance date of SPM No. 089-43173-00453. If the result of the any conducted after the issuance date of SPM No. 089-43173-00453 is more than twenty percent (20%) greater than the last test result for that same boiler and duct burner combination, then all of the other four (4) boiler and duct burner combinations shall be tested in an accelerated period of no more than two and one-half (2.5) years following the date the results of the 20% triggering test are submitted to IDEM.*

3. *Except as specified in the permit, one (1) boiler and duct burner combination shall be tested in each year.*

4. *One (1) boiler shall be tested not later than 180 days after the issuance date of SPM No. 089-43173-00453.*

5. *PM and PM_{10} testing of the No. 3 SPS boilers at the stack while the duct burner and SCR are not operating will establish values of $R_{B\text{-}j}$ and $R_{B10\text{-}j}$ for the compliance determination calculations. Each such boiler test shall be conducted concurrently with the required test of the boiler and duct burner.*

6. *Testing shall be conducted in accordance with 326 IAC 3-6. Pursuant 326 IAC 3-6-1, this rule applies to any emissions unit emissions testing performed to determine compliance with applicable emission limitations contained in this title, or for any other purpose requiring review and approval by the department. The owner or operator of an emissions unit shall conduct emission tests subject to this rule in accordance with any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by the department and U.S. EPA.*

These testing requirements are enforceable as a practical matter. IDEM, OAQ assigned a 20% increase threshold relative to the previous test of the 3SPS stack as indicating a significant change in the Stack's emissions performance that could signal a similar (yet undetected) increase at the remaining stacks. Exceedance of this 20% threshold would therefore trigger an accelerated testing requirement (to establish the lb/MMBtu emission rate) for each of the other four (4) 3SPS Stacks. IDEM modified D.02.3 to add clarifying language around the accelerated testing requirement for the other four (4) 3SPS Stacks if the 20% threshold is triggered.

The accelerated test schedule represents a significant commitment of resources on the part of IDEM and the source. Stack tests do not provide instant results. Tests require laboratory analysis and rather extensive calculations involving the stack flow rate and operating conditions. When a source submits the report provided by its testing contractor, IDEM's Compliance Data Section performs its own calculations that are considered to determine the compliance status.

Continuous Emissions Monitoring System (CEMS) and Continuous Opacity Monitoring (COM) Requirements:

There is no change in CEMS requirement for NOx and CO as a result of this modification.

(b) The Compliance Monitoring Requirements applicable to this proposed modification are as follows:

Emission Unit	Type of Parametric Monitoring	Frequency	Range or Specification
3SPS/SCR	Fuel Gas Pressure Monitoring	Continuous	Operated and maintained per manufacturer's specifications.
3SPS/SCR	Fuel Gas Temperature Monitoring	Continuous	Operated and maintained per manufacturer's specifications.
3SPS/SCR	Ammonia Injection Rate	Continuous	Operated and maintained per manufacturer's specifications.

These monitoring conditions are necessary because the SCR for each 3SPS boiler must operate properly to assure compliance with the limits to render 326 IAC 2-2 (PSD) and 326 IAC 2-3 (Emission Offset) not applicable.

Proposed Changes

As part of this permit approval, the permit may contain new or different permit conditions and some conditions from previously issued permits/approvals may have been corrected, changed, or removed. These corrections, changes, and removals may include Title I changes.

The following changes listed below are due to the proposed modification. Deleted language appears as ~~strikethrough~~ text and new language appears as **bold** text (these changes may include Title I changes):

- IDEM, OAQ has made changes in compliance determination equations for PM and PM_{10} emission calculations, and testing requirements for SPS boilers and duct burners as requested by source on concerned of EPA. See the Section "Description of Proposed Modification" for details.

Therefore, the permit was updated as follows:

SECTION D.02 EMISSIONS UNIT OPERATION CONDITIONS – TGU, FCU, and 3SPS Particulate Limits

*****

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

*****

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

D.02.2 Compliance Determination Requirements

Pursuant to SPM 089-43173-00453, the following equations shall be used to determine compliance with the PM and PM_{10} limits in Condition D.02.1.

(a) The following equations shall be used to determine compliance with the PM limit for the Claus offgas treater tail gas units A and B

(1)

$$PM_{TGU\ A} = \frac{ER_{TGU\ A} \times H_{TGU\ A}}{2{,}000\ lb/ton}$$

Where:

$PM_{TGU\ A}$ = PM emissions of TGU A, tons/month
$ER_{TGU\ A}$ = PM emission rate of TGU A, lb/hr, determined in the most recent test required by Condition D.4.9(a)
$H_{TGU\ A}$ = Monthly hours of operation of TGU A, hr/month

(2)

$$PM_{TGU\ B} = \frac{ER_{TGU\ B} \times H_{TGU\ B}}{2{,}000\ lb/ton}$$

Where:

$PM_{TGU\ B}$ = PM emissions of TGU B, tons/month
$ER_{TGU\ B}$ = PM emission rate of TGU B, lb/hr, determined in the most recent test required by condition D.4.9(b)
$H_{TGU\ B}$ = Monthly hours of operation of TGU B, hr/month

(3)

$$PM_{TGU\ An} = \sum_{i=1}^{12} (PM_{TGU\ A} + PM_{TGU\ B})_i$$

Where:

$PM_{TGU\ An}$ = Total combined PM emissions of TGU A and TGU B, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

(b) The following equations shall be used to determine compliance with the PM limit for fluid catalytic cracking unit 500:

(1)

$$PM_{FCU\ 500} = \frac{EF_{FCU\ 500} \times C_{FCU\ 500}}{2{,}000\ lb/ton}$$

Where:

$PM_{FCU\ 500}$ = PM emissions of FCU 500, tons/month
$EF_{FCU\ 500}$ = PM_{TOTAL} emission rate of FCU 500, lb/1,000 lb of coke burned, determined in the most recent test required by Condition D.21.10.
$C_{FCU\ 500}$ = Amount of coke burned in FCU 500, lb/month

(2)

$$PM_{FCU\ 500\ An} = \sum_{i=1}^{12} (PM_{FCU\ 500})_i$$

Where:

$PM_{FCU\ 500\ An}$ = Total PM emissions of FCU 500, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

However, the value of $PM_{FCU\ 500\ An}$ shall not be less than 117.20 tons per twelve (12) consecutive month period.

(c) The following equations shall be used to determine compliance with the PM limit for fluid catalytic cracking unit 600:

(1)

$$PM_{FCU\ 600} = \frac{EF_{FCU\ 600} \times C_{FCU\ 600}}{2{,}000\ lb/ton}$$

Where:

$PM_{FCU\ 600}$ = PM emissions of FCU 600, tons/month
$EF_{FCU\ 600}$ = PM_{TOTAL} emission rate of FCU 600, lb/1,000 lb of coke burned, determined in the most recent test required by Condition D.22.10.
$C_{FCU\ 600}$ = Amount of coke burned in FCU 600, lb/month

(2)

$$PM_{FCU\ 600\ An} = \sum_{i=1}^{12} (PM_{FCU\ 600})_i$$

Where:

$PM_{FCU\ 600\ An}$ = Total PM emissions of FCU 600, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

However, the value of $PM_{FCU\ 600\ An}$ shall not be less than 56.30 tons twelve (12) consecutive month period.

(d) The following equations shall be used to determine compliance with the PM limit for the No. 3 SPS:

(1)

$$PM_{3SPS\ SCR} = PM_{3SPS\ Boiler\ Stack} - PM_{3SPS\ Boiler}$$

Where:

$PM_{3SPS\ SCR}$ = PM emissions of No. 3 SPS boiler SCR system, tons/month
$PM_{3SPS\ Boiler\ Stack}$ = sum of boiler stack emissions, tons/month
$PM_{3SPS\ Boiler}$ = sum of boiler emissions, tons/month

And:

$$PM_{3SPS\ Boiler\ Stack} = \frac{\sum_{j=1}^{5} R_{PM\text{-}j}\ Q_{Bj}}{2{,}000\ lb/ton}$$

And:

$$PM_{3SPS\ Boiler} = \frac{\sum_{j=1}^{5} R_{B\text{-}j}\ Q_{Bj}}{2{,}000\ lb/ton}$$

Thus:

$$PM_{3SPS\ SCR} = \frac{\sum_{j=1}^{5} \left(R_{PM\text{-}j} - R_{B\text{-}j}\right) Q_{Bj}}{2{,}000\ lb/ton}$$

Where:

j = counter for stack ID's, 503-0*j*

$R_{PM\text{-}j}$ = Most recent PM test result for stack 503-0j, lb/MMBtu. **These values shall be calculated based on the average of the valid test runs using for each test run the average PM test result for stack 503-0j in lb/hr divided by the average hourly heat input of the boilers and duct burners calculated in accordance with section (k).** Until the results of tests required by Condition D.02.3~~(a)~~ are available, the source shall use the following values of $R_{PM\text{-}j}$:

j	Date	Unit	$R_{PM\text{-}j}$
1	~~10/8/2018~~ **11/16/2021**	31	~~0.0043~~ **0.0014**
2	10/9/2018	32	~~0.0036~~ **0.0044**
3	10/11/2018	33	~~0.0053~~ **0.0063**
4	10/12/2018	34	~~0.0051~~ **0.0062**
5	4/16/2019	36	~~0.0012~~ **0.0014**

$R_{B\text{-}j}$ = Most recent PM test result for a boiler exhausting to the stack 503-0j, lb/MMBtu, **calculated based on the average of the valid test runs using for each test run the average PM test result for stack 503-0j in lb/hr divided by the average hourly heat input of the boiler calculated in accordance with section (k).** Until the results of tests required by Condition D.02.3~~(b)~~ are available, $R_{B\text{-}j}$ = 0.0019 lb/MMBtu.

However, the value of $R_{B\text{-}j}$ shall not be greater than 0.0019 lb/MMBtu.

Q_{Bj} = Combined firing rate for all fuels in the boiler exhausting to stack 503-0j, MMBtu/month **based on the average monthly heat input of the boiler calculated in accordance with section (k).**
Note that boilers 31-34 exhaust to stacks 503-01 through 503-04, respectively and boiler 36 exhausts to stack 503-05

(2)

$$PM_{3SPS\ DB} = \frac{\sum_{j=1}^{5} R_{PM\text{-}j}\ Q_{Dj}}{2{,}000\ lb/ton}$$

Where:

$PM_{3SPS\ DB}$ = PM emissions of No. 3 SPS duct burners, tons/month
j = counter as in paragraph (1)
$R_{PM\text{-}j}$ = as in paragraph (1)

Q_{Dj} = Combined firing rate for all fuels in the duct burner exhausting to stack 503-0*j*, MMBtu/month **based on the average monthly heat input of the duct burner calculated in accordance with section (k).**

Note that duct burners 31-34 exhaust to stacks 503-01 through 503-04, respectively and duct burner 36 exhausts to stack 503-05

(3)

$$PM_{3SPS\ An} = \sum_{i=1}^{12}(PM_{3SPS\ SCR} + PM_{3SPS\ DB})_i$$

Where:

$PM_{3SPS\ An}$ = Total combined PM emissions of No. 3 SPS, tons per twelve (12) consecutive month period

i = a counter for the most recent twelve (12) months

(e) The following equation shall be used to determine compliance with the combined PM limit for the Claus offgas treater tail gas units A and B, fluid catalytic cracking units 500 and 600, and No. 3 SPS boiler and duct burners in Condition D.02.1(a):

$$PM_{An} = PM_{TGU\ An} + PM_{FCU\ 500\ An} + PM_{FCU\ 600\ An} + PM_{3SPS\ An}$$

Where:

PM_{An} = Total PM emissions of the units, tons per twelve (12) consecutive month period

$PM_{TGU\ An}$ = determined in paragraph (a)(3)

$PM_{FCU\ 500\ An}$ = determined in paragraph (b)(2)

$PM_{FCU\ 600\ An}$ = determined in paragraph (c)(2)

$PM_{3SPS\ An}$ = determined in paragraph (d)(3)

(f) The following equations shall be used to determine compliance with the PM_{10} limit for the Claus offgas treater tail gas units A and B

(1)

$$PM_{10\ TGU\ A} = \frac{ER_{10\ TGU\ A} \times H_{TGU\ A}}{2{,}000\ lb/ton}$$

Where:

$PM_{10\ TGU\ A}$ = PM_{10} emissions of TGU A, tons/month

$ER_{10\ TGU\ A}$ = PM_{10} emission rate of TGU A, lb/hr, determined in the most recent test required by Condition D.4.9(a).

$H_{TGU\ A}$ = Monthly hours of operation of TGU A, hr/month

(2)

$$PM_{10\ TGU\ B} = \frac{ER_{10\ TGU\ B} \times H_{TGU\ B}}{2{,}000\ lb/ton}$$

Where:

$PM_{10\ TGU\ B}$ = PM_{10} emissions of TGU B, tons/month

$ER_{10\ TGU\ B}$ = PM_{10} emission rate of TGU B, lb/hr, determined in the most recent test required by Condition D.4.9(b).

$H_{TGU\ B}$ = Monthly hours of operation of TGU B, hr/month

(3)

$$PM_{10\ TGU\ An} = \sum_{i=1}^{12} (PM_{10\ TGU\ A} + PM_{10\ TGU\ B})_i$$

Where:

$PM_{10\ TGU\ An}$ = Total combined PM_{10} emissions of TGU A and TGU B, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

(g) The following equations shall be used to determine compliance with the PM_{10} limit for fluid catalytic cracking unit 500:

(1)

$$PM_{10\ FCU\ 500} = \frac{EF_{10\ FCU\ 500} \times C_{FCU\ 500}}{2{,}000\ lb/ton}$$

Where:

$PM_{10\ FCU\ 500}$ = PM_{10} emissions of FCU 500, tons/month
$EF_{10\ FCU\ 500}$ = PM_{10} emission rate of FCU 500, lb/1,000 lb of coke burned, determined in the most recent test required by Condition D.21.10.
$C_{FCU\ 500}$ = Amount of coke burned in FCU 500, lb/month

(2)

$$PM_{10\ FCU\ 500\ An} = \sum_{i=1}^{12} (PM_{10\ FCU\ 500})_i$$

Where:

$PM_{10\ FCU\ 500\ An}$ = Total PM_{10} emissions of FCU 500, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

However, the value of $PM_{10\ FCU\ 500\ An}$ shall not be less than 117.20 tons per twelve (12) consecutive month period.

(h) The following equations shall be used to determine compliance with the PM_{10} limit for fluid catalytic cracking unit 600:

(1)

$$PM_{10\ FCU\ 600} = \frac{EF_{10\ FCU\ 600} \times C_{FCU\ 600}}{2{,}000\ lb/ton}$$

Where:

$PM_{10\ FCU\ 600}$ = PM_{10} emissions of FCU 600, tons/month
$EF_{10\ FCU\ 600}$ = PM_{10} emission rate of FCU 600, lb/1,000 lb of coke burned, determined in the most recent test required by Condition D.22.10.
$C_{FCU\ 600}$ = Amount of coke burned in FCU 600, lb/month

(2)

$$PM_{10\ FCU\ 600\ An} = \sum_{i=1}^{12} (PM_{10\ FCU\ 600})_i$$

Where:

$PM_{10\ FCU\ 600\ An}$ = Total PM_{10} emissions of FCU 600, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

However, the value of $PM_{10\ FCU\ 600\ An}$ shall not be less than 56.30 tons per twelve (12) consecutive month period.

(i) The following equations shall be used to determine compliance with the PM_{10} limit for the No. 3 SPS:

(1)

$$PM_{10\ 3SPS\ SCR} = PM_{10\ 3SPS\ Boiler\ Stack} - PM_{10\ 3SPS\ Boiler}$$

Where:

$PM_{10\ 3SPS\ SCR}$ = PM_{10} emissions of No. 3 SPS boiler SCR system, tons/month
$PM_{10\ 3SPS\ Boiler\ Stack}$ = sum of boiler stack emissions, tons/month
$PM_{10\ 3SPS\ Boiler}$ = sum of boiler emissions, tons/month

And:

$$PM_{10\ 3SPS\ Boiler\ Stack} = \frac{\sum_{j=1}^{5} R_{PM10\text{-}j}\ Q_{Bj}}{2{,}000\ lb/ton}$$

And:

$$PM_{10\ 3SPS\ Boiler} = \frac{\sum_{j=1}^{5} R_{B10\text{-}j}\ Q_{Bj}}{2{,}000\ lb/ton}$$

Thus:

$$PM_{10\ 3SPS\ SCR} = \frac{\sum_{j=1}^{5} \left(R_{PM10\text{-}j} - R_{B10\text{-}j}\right) Q_{Bj}}{2{,}000\ lb/ton}$$

Where:

j = counter for stack ID's, 503-0*j*

$$\mathbf{R_{PM10\text{-}j} = \sum_{j=1}^{5} \left(R_{CPM\text{-}j} + R_{PM\text{-}j}\right)}$$

Where:

$R_{PM\text{-}j}$ = PM emission rate for the stack 503-0j, lb/MMBtu, calculated in accordance with section (d)(1)

$$\mathbf{R_{CPM\text{-}j} = (A \times S + B) \times CSF}$$

$R_{CPM\text{-}j}$ = Condensible PM_{10} emission rate for the stack 503-0j, lb/MMBtu
S = Average monthly total sulfur content of fuels, calculated as H2S, combusted by the boiler and duct burner, ppm

A = Constant, in lb/MMBtu-ppm, determined after submittal of each stack test required by Condition D.02.3, rounded to two significant digits. Until the results of the tests required by Condition D.0.2.3(b) the value of 0.00021 lb/MMBtu-ppm shall be used.

B = Constant, in lb/MMBtu, determined after submittal of each stack test required by Condition D.02.3, rounded to two significant digits. Until the results of the tests required by Condition D.0.2.3(b) the value of 0.0059 lb/MMBtu shall be used.

CSF = Constant, conditional safety factor. Starting with issuance of SPM No. 089-45450-00453, and after each boiler and duct burner combination has been tested in accordance with D.02.3(a)(5), if the monthly average ammonia injection rate (lb/hr) is greater than the value determined in accordance D.02.3(a)(5), CSF shall be equal to a safety factor of 1.3. Otherwise, CSF shall be equal to 1.

Constants A and B shall be based on a linear regression of the condensible PM_{10}, in lb/MMBtu, for all valid condensable PM_{10} tests of all of the 3SPS Boilers (stacks identified as 503-1 through 503-5) calculated based on the average of the valid test runs using the average condensable PM_{10} test result for stack 503-0j in lb/hr divided by the average hourly heat input of the boiler calculated in accordance with section (k) and the hourly average fuel sulfur content, calculated as H2S, in ppm, for all fuels burned during the associated test runs.

Boiler / DB	Test Date	CPM	Fuel Gas Total Sulfur
		lb/MMBtu	(ppm)
Boiler / DB 32	8/3/2015	0.018	43
Boiler / DB 36	8/5/2015	0.016	55
Boiler / DB 32	10/20/2015	0.019	64
Boiler / DB 32	1/28/2016	0.020	66
Boiler / DB 36	11/2/2016	0.023	89
Boiler / DB 31	10/8/2018	0.013	37
Boiler / DB 32	10/9/2018	0.015	32
Boiler / DB 33	10/11/2018	0.012	25
Boiler / DB 34	10/12/2018	0.008	21
Boiler / DB 36	4/16/2019	0.011	34
Boiler / DB 31	11/16/2021	0.012	34
Slope (A)		0.00021 lb/MMBtu-ppm	
Y-Intercept (B)		0.0059 lb/MMBtu	

~~$R_{PM10\ j}$ = Most recent PM_{10} test result for stack 503-0j, lb/MMBtu. Until the results of tests required by Condition D.02.3(a) are available, the source shall use the following values of $R_{PM10\ j}$:~~

~~j~~	~~Date~~	~~Unit~~	~~$R_{PM10\ j}$~~
~~1~~	~~10/8/2018~~	~~31~~	~~0.0154~~
~~2~~	~~10/9/2018~~	~~32~~	~~0.0163~~
~~3~~	~~10/11/2018~~	~~33~~	~~0.0151~~
4	~~10/12/2018~~	~~34~~	~~0.0114~~

~~j~~	~~Date~~	~~Unit~~	~~$R_{PM10\text{-}j}$~~
~~5~~	~~4/16/2019~~	~~36~~	~~0.0109~~

$R_{B10\text{-}j}$ = Most recent PM_{10} test result for a boiler exhausting to the stack 503-0j, lb/MMBtu **calculated based on the average of the valid test runs using the average PM10 test result for stack 503-0j in lb/hr divided by the average hourly heat input of the boiler calculated in accordance with section (k).** Until the results of tests required by Condition D.02.3~~(b)~~ are available, $R_{B10\text{-}j}$ = 0.0075 lb/MMBtu.

However, the value of $R_{B10\text{-}j}$ shall not be greater than 0.0075 lb/MMBtu.

Q_{Bj} = Combined firing rate for all fuels in the boiler exhausting to stack 503-0j, MMBtu/month **based on the average monthly heat input of the boiler calculated in accordance with section (k).**

Note that boilers 31-34 exhaust to stacks 503-01 through 503-04, respectively and boiler 36 exhausts to stack 503-05

(2)

$$PM_{10\ 3SPS\ DB} = \frac{\sum_{j=1}^{5} R_{PM10\text{-}j}\ Q_{Dj}}{2{,}000\ \text{lb/ton}}$$

Where:

$PM_{10\ 3SPS\ DB}$ = PM_{10} emissions of No. 3 SPS duct burners, tons/month
j = counter as in paragraph (1)
$R_{PM10\text{-}j}$ = as in paragraph (1)
Q_{Dj} = Combined firing rate for all fuels in the duct burner exhausting to stack 503-0*j*, MMBtu/month **based on the average monthly heat input of the duct burner calculated in accordance with section (k).**

Note that duct burners 31-34 exhaust to stacks 503-01 through 503-04, respectively and duct burner 36 exhausts to stack 503-05

(3)

$$PM_{10\ 3SPS\ An} = \sum_{i=1}^{12} (PM_{10\ 3SPS\ SCR} + PM_{10\ 3SPS\ DB})_i$$

Where:

$PM_{10\ 3SPS\ An}$ = Total combined PM_{10} emissions of No. 3 SPS, tons per twelve (12) consecutive month period
i = a counter for the most recent twelve (12) months

(j) The following equation shall be used to determine compliance with the combined PM_{10} limit for the Claus offgas treater tail gas units A and B, fluid catalytic cracking units 500 and 600, and No. 3 SPS boiler and duct burners in Condition D.02.1(a):

$$PM_{10\ An} = PM_{10\ TGU\ An} + PM_{10\ FCU\ 500\ An} + PM_{10\ FCU\ 600\ An} + PM_{10\ 3SPS\ An}$$

Where:

$PM_{10\ An}$ = Total PM_{10} emissions of the units, tons per twelve (12) consecutive month period
$PM_{10\ TGU\ An}$ = determined in paragraph (f)(3)

$PM_{10\ FCU\ 500\ An}$ = determined in paragraph (g)(2)
$PM_{10\ FCU\ 600\ An}$ = determined in paragraph (h)(2)
$PM_{10\ 3SPS\ An}$ = determined in paragraph (i)(3)

(k) For the purposes of calculating the heat input in sections (d) and (i), when combusting refinery fuel gas in the boilers and duct burners, the Permittee shall continuously analyze the higher heating value (HHV) of the refinery fuel gas using gas chromatography (GC) technology, and shall continuously measure and record the fuel flow to the boilers and duct burners. Data substitution will be used during periods of missing data such as periods of GC maintenance or malfunction. The best available estimate of the parameter, based on all available process data may be used for substitution. Heat input to the boilers and duct burners will be calculated as follows:

$$\boldsymbol{HI_{rate-gas} = \frac{GAS_{rate} \times HHV_{gas}}{10^6}}$$

Where:

$\boldsymbol{HI_{rate-gas}}$ **= Heat input rate, in MMBtu**
$\boldsymbol{GAS_{rate}}$ **= Gas volumetric flow, in scf**
$\boldsymbol{HHV_{gas}}$ **= Higher heating value of refinery fuel, in Btu/scf**
$\boldsymbol{10^6}$ **= Conversion of Btu to MMBtu**

(m) Starting with issuance of SPM No. 089-45450-00453, the permittee shall perform preventive maintenance and testing on the SCR catalyst during each planned 3SPS boiler and duct burner outage. Preventive maintenance and testing on the SCR catalyst shall be performed at least once every three years.

D.02.3 Performance Testing Requirements

(a) In order to demonstrate compliance with Conditions D.02.1 ~~and D.24.2~~, not later than 180 days after the issuance date of SPM No. 089-43173-00453, the Permittee shall perform PM and PM_{10} testing of one boiler and duct burner combination in the No. 3 Stanolind Power Station listed in the table below:

Boiler	Duct Burner	Stack
#31	#31	503-01
#32	#32	503-02
#33	#33	503-03
#34	#34	503-04
#36	#36	503-05

Utilizing methods as approved by the Commissioner, subject to the following:

(1) ~~Subsequent to the initial test required by Condition D.02.3(a) and if necessary, testing required by Condition D.02.3(a)(4), one (1) No. 3 SPS boiler and duct burner combination shall be tested each twelve (12) consecutive month period.~~ **At least one (1) No. 3 SPS boiler and duct burner combination shall be tested at least once every twelve (12) consecutive month period from the date of the most recent valid test.**

(2) ~~The unit selected for testing shall be the boiler and duct burner combination that has operated for the longest time since a previous test.~~ **Testing will be conducted for the boiler and duct burner combination for which the longest time has passed since the last test for that combination.**

(3) **If the lb/MMBtu emission rate of PM_{10} from of any test conducted is greater than twenty percent (20%) of the value established in the most recent test for that boiler and duct burner combination, then the Permittee shall test in accordance with the schedule under Condition D.02.3(b) (Alternative Triggered Testing Requirement).**

(~~3~~**4**) Each No. 3 SPS boiler and duct burner combination listed in the table in paragraph (a) shall be tested at least once in every five (5) year period from the date of its previous test **conducted after issuance of SPM No. 089-43173-00453**.

~~(4) If the result of the first test conducted after the issuance date of SPM No. 089-43173-00453 is more than twenty percent (20%) greater than the last test result for that boiler and duct burner combination, then all of the remaining four (4) boiler and duct burner combinations shall be tested in a period of no more than two and one-half (2.5) years after the results of the triggering test are available. first test after the issuance date of SPM No. 089-43173-00453. A boiler and duct burner combination for which PM10 occurred within 2.5 years prior to the date of the triggering test are exempt from this requirement.~~

(5) Starting with issuance of SPM No. 089-45450-00453, a test shall not be considered a valid test, and the Permittee will not have met the requirement of this condition to test, unless

(i) The average total ammonia solution injection rate (in lb/hour) for the tested boiler and duct burner combination for all runs is greater than the maximum of the average monthly total ammonia injection rate from the preceding five years (in lb/hour); and

(ii) The ratio of average total ammonia solution injection rate divided by the total sulfur content in the fuel gas in lb/hr/ppm is greater than two (2).

(iii) For the purposes of calculating the average monthly total ammonia injection rate, hours where the total 3SPS heat input rate is zero shall be excluded from the average. Total ammonia injection rate during the test as well as the calculated average total ammonia injection from the preceding five-year period shall be included in the results submitted in accordance with Condition C.8(c).

(b) Alternative Triggered Testing Requirement:
If a valid test establishes a PM_{10} emission rate that is greater than the 20% of the value established in the most recent test for that boiler and duct burner combination, submission of such test results to IDEM triggers the following accelerated testing schedule for the remaining four (4) boiler and duct burner combinations.

(1) The Permittee must conduct a valid test for PM and PM_{10} on each of the other four (4) boiler and duct burner combinations no more than 2.5 years (30 months) from the date the Permittee submits the triggering test results to IDEM.

(2) Condition D.02.3(a)(1) will continue to apply to accelerated testing conducted pursuant to this subpart (b).

(3) Conditions D.02.3(a)(2) and D.02.3(a)(3) will not apply to accelerated testing conducted pursuant to this subpart (b).

(4) Upon completion of the fourth and final boiler and duct burner combination valid test conducted pursuant to this subpart (b), future tests shall be conducted in accordance with D.02.3(a).

(~~b~~**c**) In order to demonstrate compliance with Conditions D.02.1 ~~and D.24.1~~, not later than 180 days after the issuance date of SPM No. 089-43173-00453, the Permittee shall perform PM and PM_{10} testing of the boiler in the No. 3 Stanolind Power Station selected for testing required by Condition D.02.3(a), utilizing methods as approved by the Commissioner, subject to the following:

(1) Subsequent to the initial test required by Condition D.02.3(~~b~~**c**), **at least** one (1) No. 3 SPS boiler listed in the table in paragraph (a) shall **be tested** ~~conduct an initial test each twelve (12) consecutive month period, in conjunction with the test required by Condition D.02.3(a), or as required by Condition D.02.3(a)(4).~~ **in conjunction with the subsequent test required by Condition D.02.3(a) until all five (5) boilers have been tested. After all five (5) boilers have been tested, each No. 3 SPS boiler listed in the table in paragraph (a) shall be tested for PM and PM_{10} at least once in every five (5) year period from the date of its previous test conducted after issuance of SPM No. 089-43173-00453.**

~~(2) The unit selected for testing shall be the boiler tested in conformance with Condition D.02.3(a).~~

~~(3) Each No. 3 SPS boiler listed in the table in paragraph (a) shall be tested at least once in every five (5) year period from the date of its previous test conducted after issuance of SPM 089-43173-00453.~~

(~~c~~**d**) 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. PM_{10} includes filterable and condensable PM.

*****

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

D.02.4 Fuel Gas Temperature and Pressure Monitoring

A continuous monitoring system for the 3SPS boilers and associated duct burners shall be calibrated, maintained, and operated for measuring the fuel gas temperature and pressure. For the purpose of this condition, continuous means no less often than once per fifteen (15) minutes.

D.02.5 Ammonia Injection Rate Monitoring

The Permittee shall monitor and record the ammonia injection rate on each Selective Catalytic Reduction (SCR) system continuously when the associated processes are in operation. For the purpose of this condition, continuous means no less often than once per fifteen (15) minutes.

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

D.02.~~4~~**6** Record Keeping Requirements

(a) *****

(b) In order to document the compliance status with Condition D.02.1, the Permittee shall maintain ~~monthly~~ records of: ~~the hours of operation for TGU A and TGU B~~.

(1) Monthly hours of operation for TGU A and TGU B;

(2) **Hourly and monthly average heat input rate of refinery fuel gas combusted by the No. 3 SPS boilers and duct burners; and**

(3) **Monthly values of A, S, B, and CSF determined in accordance with D.02.2(i)(1).**

(4) **Preventive maintenance and testing records for the SCR catalyst during each planned 3SPS boiler and duct burner outage.**

(b) **To document the compliance status with Condition D.02.4, the Permittee shall maintain continuous fuel gas temperature and pressure records for the boilers and duct burners.**

(c) **In order to document the compliance status with Condition D.02.3(a)(5) and D.02.5, the Permittee shall maintain continuous records of the ammonia injection rate.**

(~~c~~**d**) Condition D.21.17(e) contains the requirement for the Permittee to maintain a record of the monthly amount of coke burned in FCU 500.

(~~d~~**e**) Condition D.22.17(e) contains the requirement for the Permittee to maintain a record of the monthly amount of coke burned in FCU 600.

(~~e~~**f**) Condition D.24.14(c) contains the requirement for the Permittee to maintain a record of the monthly firing rate the No. 3 SPS boilers and duct burners.

(~~f~~**g**) Section C - General Record Keeping Requirements contains the Permittee's obligations with regard to the records required by this condition.

D.02.~~5~~**7** Reporting Requirements

(a) *****

*****

(3) **Monthly values of A, S, B, and CSF determined in accordance with D.02.2(i)(1) for each month of the quarter.**

*****

Conclusion and Recommendation

Unless otherwise stated, information used in this review was derived from the application and additional information submitted by the applicant. An application for the purposes of this review was received on May 23, 2022.

The operation of this proposed modification shall be subject to the conditions of the attached proposed Significant Permit Modification No. 089-45450-00453.

The staff recommends to the Commissioner that the Part 70 Significant Permit Modification be approved.

IDEM Contact

(a) If you have any questions regarding this permit, please contact Aasim Noveer, 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) 234-1243 or (800) 451-6027, and ask for Aasim Noveer or (317) 234-1243.

(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 Air Permits page on the Internet at: https://www.in.gov/idem/airpermit/public-participation/; and the Citizens' Guide to IDEM on the Internet at: https://www.in.gov/idem/resources/citizens-guide-to-idem/.

Appendix A: Emission Calculations
Statistical Analysis 2022
Source Name: BP Products North America, Inc. - Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394
Significant Permit Modification No.: 089-45450-00453
Reviewer: Aasim Noveer

Boiler	Test Date	Run Number	Run Start / Run Stop	Fuel Flow Boiler (Mscf)	Boiler Fuel Measured Pressure (psig)	Boiler Fuel Measured Temp (deg F)	Fuel SG	Comp.[3] Boiler	Fuel Flow Duct Burner (Mscf)	DB Measured Fuel Pressure (psig)	DB Measured Fuel Temp (deg F)	Comp.[4] DB	Compensated Fuel Flow Rates Boiler (Mscf)	Compensated Fuel Flow Rates Duct Burner (Mscf)	High Heating Value (HHV) (Btu/Scf)	Average Total Heat Input (MMBtu/hr)	Average Fuel Gas Total Sulfur (Calculated as H2S) (ppm)	Average NH3 Solution Injection During Test (lb/hr)	Ratio (NH3 Solution Injection/Fuel Gas Total Sulfur) (lb/hr / ppm)	Test Results FPM (lb/hr)	Test Results CPM (lb/hr)	Test Results TPM (lb/hr)	Emission Factors FPM (lb/MMBtu)	Emission Factors CPM (lb/MMBtu)	Emission Factors TPM (lb/MMBtu)
Boiler 32 (SCR-on)	8/3/2015																								
		1	8/3/15 12:07 PM 8/3/15 3:17 PM	418.3	22.5	96.2	0.58	1.17	36.8	25.0	94.9	1.06	489.9	38.9	967	511.4	46.0	257.2	--	0.513	9.284	9.797	0.0010	0.018	0.019
		2	8/3/15 4:13 PM 8/3/15 7:12 PM	429.1	22.5	96.6	0.57	1.18	37.8	25.1	94.2	1.06	505.5	40.1	956	521.8	46.0	287.6	--	0.705	9.700	10.405	0.0014	0.019	0.020
		3	8/3/15 8:10 PM 8/3/15 11:11 PM	441.6	22.5	87.9	0.54	1.22	39.8	25.2	86.3	1.08	539.5	43.0	904	526.4	38.4	305.0	--	0.917	9.853	10.770	0.0017	0.019	0.020
		Average	8/3/15 12:07 PM 8/3/15 11:11 PM	429.7	22.5	93.5	0.56	1.19	38.1	25.1	91.8	1.07	511.6	40.7	942	519.9	43.4	283.3	6.5	0.712	9.612	10.324	0.0014	0.018	0.020
Boiler 36 (SCR-on)	8/5/2015																								
		1	8/5/15 8:40 AM 8/5/15 11:46 AM	417.9	22.5	97.0	0.65	1.10	33.7	25.0	90.3	1.07	460.8	35.9	1,080	536.7	53.5	230.5	--	1.434	11.596	13.030	0.0027	0.022	0.024
		2	8/5/15 12:20 PM 8/5/15 3:25 PM	411.6	22.5	99.6	0.67	1.09	33.0	25.1	95.9	1.06	447.4	34.9	1,098	529.7	55.8	221.2	--	0.451	10.371	10.822	0.0009	0.020	0.020
		3	8/5/15 4:12 PM 8/5/15 7:17 PM	407.5	22.5	94.0	0.66	1.10	32.8	25.1	90.7	1.07	448.5	35.0	1,071	517.6	55.3	201.3	--	0.515	3.317	3.832	0.0010	0.006	0.007
		Average	8/5/15 8:40 AM 8/5/15 7:17 PM	412.3	22.5	96.9	0.66	1.10	33.1	25.1	92.3	1.06	452.2	35.3	1,083	528.0	54.9	217.7	4.0	0.800	8.428	9.228	0.0015	0.016	0.017
Boiler 32 (SCR-on)	10/20/2015																								
		1	10/20/15 10:58 AM 10/20/15 12:55 PM	394.3	22.5	80.0	0.63	1.14	32.6	24.9	73.9	1.10	449.6	35.7	1,026	497.7	63.0	226.4	--	0.471	9.257	9.728	0.0009	0.019	0.020
		2	10/20/15 1:55 PM 10/20/15 3:35 PM	394.1	22.5	83.0	0.63	1.13	31.0	25.0	77.2	1.09	447.2	33.9	1,031	495.9	64.1	198.8	--	0.351	7.572	7.923	0.0007	0.015	0.016
		3	10/20/15 4:23 PM 10/20/15 5:58 PM	386.7	22.5	83.4	0.63	1.13	30.2	25.1	79.4	1.09	437.8	32.9	1,042	490.6	64.8	190.0	--	0.273	11.886	12.159	0.0006	0.024	0.025
		Average	10/20/15 10:58 AM 10/20/15 5:58 PM	391.7	22.5	82.1	0.63	1.14	31.3	25.0	76.9	1.09	444.9	34.2	1,033	494.7	64.0	205.1	3.2	0.365	9.572	9.937	0.0007	0.019	0.020
Boiler 36 (SCR-on)	10/21/2015																								
		1	10/21/15 9:55 AM 10/21/15 11:38 AM	396.9	22.5	78.2	0.61	1.16	32.2	25.1	70.3	1.11	459.6	35.7	1,001	495.7	56.1	124.9	--	0.271	6.649	6.920	0.0005	0.013	0.014
		2	10/21/15 12:25 PM 10/21/15 2:05 PM	394.8	22.5	85.7	0.61	1.15	31.4	25.1	81.0	1.09	452.8	34.2	1,008	490.7	67.7	123.7	--	0.445	7.642	8.087	0.0009	0.0156	0.0165
		3	10/21/15 2:45 PM 10/21/15 4:23 PM	394.5	22.5	86.7	0.62	1.14	30.9	25.1	81.7	1.08	449.3	33.5	1,016	490.4	68.6	116.7	--	0.146	8.212	8.358	0.0003	0.0167	0.0170
		Average	10/21/15 9:55 AM 10/21/15 4:23 PM	395.4	22.5	83.5	0.61	1.15	31.5	25.1	77.6	1.09	453.9	34.5	1,008	492.2	64.1	121.8	1.9	0.287	7.501	7.788	0.0006	0.015	0.016
Boiler 32 (SCR-on)	1/28/2016[1]																								
		2	1/28/16 11:46 AM 1/28/16 12:50 PM	380.0	22.5	65.7	0.68	1.11	31.4	25.0	62.7	1.12	423.4	35.3	1,088	499.3	63.4	239.3	--	1.150	9.592	10.742	0.0023	0.019	0.022
		3	1/28/16 1:35 PM 1/28/16 2:39 PM	366.1	22.5	66.5	0.66	1.12	30.6	25.0	63.8	1.12	411.0	34.3	1,077	479.9	69.0	213.5	--	0.974	9.87	10.844	0.0020	0.021	0.023
		4	1/28/16 3:27 PM 1/28/16 4:31 PM	391.5	22.5	66.9	0.66	1.12	32.6	25.0	64.6	1.12	439.1	36.4	1,075	510.9	65.5	255.4	--	0.819	10.7	11.519	0.0016	0.021	0.023
		Average	1/28/16 11:46 AM 1/28/16 4:31 PM	379.2	22.5	66.4	0.67	1.12	31.5	25.0	63.7	1.12	424.5	35.3	1,080	496.7	65.9	236.1	3.6	0.981	10.054	11.035	0.0020	0.020	0.022
Boiler 32 (SCR-on)	11/1/2016																								
		1	11/1/16 9:20 AM 11/1/16 10:57 AM	418.2	19.0	84.9	0.60	1.10	31.4	25.0	77.5	1.09	460.4	34.3	1,043	516.1	117.6	165.2	--	1.380	6.813	8.193	0.0027	0.013	0.016
		2	11/1/16 11:22 AM 11/1/16 12:59 PM	417.8	19.0	91.1	0.60	1.10	31.4	24.9	85.2	1.07	457.8	33.7	1,033	507.6	112.6	162.4	--	0.720	5.916	6.636	0.0014	0.012	0.013
		3	11/1/16 1:30 PM 11/1/16 3:07 PM	407.3	19.0	93.6	0.60	1.09	30.6	24.9	89.8	1.06	445.3	32.6	1,037	495.4	123.7	156.9	--	0.796	6.327	7.123	0.0016	0.013	0.014
		4	11/2/16 8:20 AM 11/2/16 9:57 AM	413.6	19.0	81.6	0.58	1.13	32.4	25.1	75.3	1.10	467.8	35.5	983	494.7	78.2	156.2	--	0.953	5.650	6.603	0.0019	0.011	0.013
		Average	11/1/16 9:20 AM 11/2/16 9:57 AM	414.2	19.0	87.8	0.60	1.11	31.5	25.0	82.0	1.1	457.8	34.0	1,024	503.4	108.0	160.2	1.5	0.962	6.177	7.139	0.0019	0.012	0.014
Boiler 36 (SCR-on)	11/2/2016																								
		1	11/2/16 12:30 PM 11/2/16 2:07 PM	419.4	19.0	79.2	0.58	1.12	36.0	25.1	73.9	1.10	471.5	39.6	989	505.3	91.6	225.3	--	1.119	11.599	12.718	0.0022	0.023	0.025
		2	11/3/16 8:15 AM 11/3/16 9:53 AM	423.3	19.0	73.1	0.60	1.12	35.9	25.0	66.8	1.11	473.7	40.0	1,016	521.7	85.7	257.8	--	1.069	12.543	13.612	0.0020	0.024	0.026
		3	11/3/16 10:20 AM 11/3/16 11:57 AM	414.2	19.0	76.0	0.59	1.12	35.6	25.1	71.8	1.10	464.7	39.3	1,011	509.5	91.8	242.4	--	0.474	12.291	12.765	0.0009	0.024	0.025
		4	11/3/16 12:20 PM 11/3/16 1:57 PM	424.2	19.0	79.1	0.58	1.13	36.2	25.1	75.0	1.10	479.1	39.8	1,007	522.8	86.9	256.1	--	1.263	11.410	12.673	0.0024	0.022	0.024
		Average	11/2/16 12:30 PM 11/3/16 1:57 PM	420.3	19.0	76.9	0.59	1.12	35.9	25.1	71.9	1.1	472.2	39.7	1,006	514.8	89.0	245.4	2.8	0.981	11.961	12.942	0.0019	0.023	0.025

Appendix A: Emission Calculations
Statistical Analysis 2022

Source Name: BP Products North America, Inc. - Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394
Significant Permit Modification No.: 089-45450-00453
Reviewer: Aasim Noveer

Boiler	Test Date	Run Number	Run Start	Run Stop	Fuel Flow Boiler (Mscf)	Boiler Fuel Measured Pressure (psig)	Boiler Fuel Measured Temp (deg F)	Fuel SG	Comp.[3] Boiler	Fuel Flow Duct Burner (Mscf)	DB Measured Fuel Pressure (psig)	DB Measured Fuel Temp (deg F)	Comp.[4] DB	Compensated Fuel Flow Rates Boiler (Mscf)	Compensated Fuel Flow Rates Duct Burner (Mscf)	High Heating Value (HHV) (Btu/Scf)	Average Total Heat Input (MMBtu/hr)	Average Fuel Gas Total Sulfur (Calculated as H2S) (ppm)	Average NH3 Solution Injection During Test (lb/hr)	Ratio (NH3 Solution Injection/Fuel Gas Total Sulfur) (lb/hr / ppm)	Test Results FPM (lb/hr)	Test Results CPM (lb/hr)	Test Results TPM (lb/hr)	Emission Factors FPM (lb/MMBtu)	Emission Factors CPM (lb/MMBtu)	Emission Factors TPM (lb/MMBtu)
Boiler 31 (SCR-on)	10/8/2018																									
		1	10/8/18 8:50 AM	10/8/18 10:05 AM	477.4	19.0	85.1	0.60	1.11	38.8	25.1	85.9	1.08	528.9	41.9	936	534.3	36.9	116.5	--	3.501	6.092	9.593	0.0066	0.011	0.018
		2	10/8/18 10:44 AM	10/8/18 12:11 PM	477.4	19.0	90.8	0.60	1.10	38.4	25.1	92.2	1.07	523.3	41.0	944	532.9	37.9	107.2	--	2.140	6.780	8.920	0.0040	0.013	0.017
		3	10/8/18 12:40 PM	10/8/18 1:54 PM	477.4	19.0	95.5	0.60	1.09	38.3	25.2	97.9	1.06	521.2	40.5	945	530.6	37.6	102.0	--	2.123	7.318	9.441	0.0040	0.014	0.018
		Average	10/8/18 8:50 AM	10/8/18 1:54 PM	477.4	19.0	90.5	0.60	1.10	38.5	25.1	92.0	1.07	524.5	41.1	942	532.6	37.4	108.5	2.9	2.588	6.730	9.318	0.0049	0.013	0.017
Boiler 32 (SCR-on)	10/9/2018																									
		1	10/9/18 8:15 AM	10/9/18 9:29 AM	454.8	19.0	87.4	0.57	1.13	30.3	24.9	88.2	1.07	513.2	32.4	924	503.9	34.4	114.0	--	2.439	8.379	10.818	0.0048	0.017	0.021
		2	10/9/18 9:55 AM	10/9/18 11:10 AM	454.9	19.0	91.4	0.57	1.13	30.9	24.8	93.6	1.05	512.3	32.6	924	503.5	31.1	129.8	--	2.566	7.247	9.813	0.0051	0.014	0.019
		3	10/9/18 11:35 AM	10/9/18 12:49 PM	454.7	19.0	95.2	0.57	1.12	30.7	24.6	97.9	1.04	509.7	32.0	923	499.9	31.5	130.1	--	1.690	7.685	9.375	0.0034	0.015	0.019
		Average	10/9/18 8:15 AM	10/9/18 12:49 PM	454.8	19.0	91.3	0.57	1.13	30.7	24.8	93.2	1.05	511.7	32.3	923	502.4	32.3	124.6	3.9	2.232	7.770	10.002	0.0044	0.015	0.020
Boiler 33 (SCR-on)	10/11/2018 [2, 5]																									
		1	10/11/18 8:25 AM	10/11/18 9:40 AM	466.2	19.0	64.1	0.53	1.19	36.4	25.1	62.6	1.13	557.0	40.9	849	507.9	23.7	133.2	--	3.259	6.042	9.301	0.0064	0.012	0.018
		2	10/11/18 10:07 AM	10/11/18 11:22 AM	465.1	19.0	67.2	0.53	1.19	36.5	25.0	65.3	1.12	553.8	40.8	849	505.1	25.7	128.2	--	2.901	5.338	8.239	0.0057	0.011	0.016
		4	10/11/18 2:34 PM	10/11/18 3:49 PM	456.5	19.0	72.7	0.53	1.19	35.5	24.9	72.9	1.10	541.1	39.0	849	492.7	24.5	126.6	--	3.308	6.180	9.488	0.0067	0.013	0.019
		Average	10/11/18 8:25 AM	10/11/18 3:49 PM	462.6	19.0	68.0	0.53	1.19	36.1	25.0	67.0	1.11	550.6	40.2	849	501.9	24.6	129.3	5.3	3.156	5.853	9.009	0.0063	0.012	0.018
Boiler 34 (SCR-on)	10/12/2018 [5]																									
		1	10/12/18 7:48 AM	10/12/18 9:02 AM	487.8	19.0	61.8	0.53	1.20	37.2	25.3	61.2	1.13	584.1	42.2	849	532.0	21.2	118.5	--	5.702	3.287	8.989	0.0107	0.006	0.017
		2	10/12/18 9:26 AM	10/12/18 10:39 AM	483.9	19.0	65.5	0.53	1.19	37.5	25.2	64.9	1.12	577.1	42.1	849	526.0	20.9	137.9	--	2.304	3.718	6.022	0.0044	0.007	0.011
		3	10/12/18 11:00 AM	10/12/18 12:13 PM	488.8	19.0	66.3	0.53	1.19	37.5	25.0	64.2	1.12	582.9	42.0	849	530.8	21.3	133.1	--	1.895	5.220	7.115	0.0036	0.010	0.013
		Average	10/12/18 7:48 AM	10/12/18 12:13 PM	486.8	19.0	64.5	0.53	1.19	37.4	25.2	63.4	1.13	581.4	42.1	849	529.6	21.1	129.8	6.1	3.300	4.075	7.375	0.0062	0.008	0.014
Boiler 36 (SCR-on)	4/16/2019																									
		1	4/16/19 9:00 AM	4/16/19 10:15 AM	477.8	19.5	71.5	0.52	1.21	36.2	25.0	67.4	1.11	577.2	40.3	876	540.9	31.1	306.3	--	0.811	4.767	5.578	0.0015	0.009	0.010
		2	4/16/19 11:10 AM	4/16/19 12:25 PM	484.8	19.5	81.2	0.52	1.20	36.2	25.0	78.4	1.09	580.5	39.5	883	547.5	35.3	311.4	--	0.757	6.026	6.783	0.0014	0.011	0.012
		3	4/16/19 1:00 PM	4/16/19 2:15 PM	483.5	19.5	86.0	0.52	1.19	36.5	25.0	84.0	1.08	575.0	39.4	873	536.4	35.5	294.7	--	0.668	7.532	8.200	0.0012	0.014	0.015
		Average	4/16/19 9:00 AM	4/16/19 2:15 PM	482.0	19.5	79.6	0.52	1.20	36.3	25.0	76.6	1.09	577.6	39.7	877	541.6	34.0	304.1	9.0	0.745	6.108	6.854	0.0014	0.011	0.013
Boiler 31 (SCR-on)	11/16/2021																									
		1	11/16/21 8:40 AM	11/16/21 9:43 AM	414.5	35.8	72.4	0.47	1.55	48.7	25.0	67.5	1.11	641.8	54.2	791	550.6	30.6	153.6	--	0.690	6.039	6.729	0.0013	0.011	0.012
		2	11/16/21 10:22 AM	11/16/21 11:25 AM	413.6	35.9	73.9	0.47	1.55	48.2	25.0	68.7	1.11	639.9	53.5	799	554.0	34.7	153.2	--	0.968	6.479	7.447	0.0017	0.012	0.013
		3	11/16/21 11:46 AM	11/16/21 12:49 PM	413.6	35.8	78.3	0.48	1.52	47.8	25.0	75.0	1.10	627.6	52.4	807	549.0	35.6	150.7	--	0.781	6.734	7.515	0.0014	0.012	0.014
		4	11/16/21 1:08 PM	11/16/21 2:11 PM	405.2	36.2	78.0	0.50	1.50	45.9	25.0	75.7	1.10	607.2	50.2	836	549.7	36.4	158.1	--	0.547	7.540	8.087	0.0010	0.014	0.015
		Average	11/16/21 10:22 AM	11/16/21 2:11 PM	411.7	36.0	75.6	0.48	1.53	47.6	25.0	71.7	1.1	629.1	52.6	808	550.8	34.3	153.9	4.5	0.7	6.7	7.4	0.0014	0.012	0.014

Appendix A: Emission Calculations
Statistical Analysis 2022
Source Name: BP Products North America, Inc. - Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394
Significant Permit Modification No.: 089-45450-00453
Reviewer: Aasim Noveer

Boiler	Test Date	Run Number		Fuel Flow	Boiler Fuel Measured Pressure	Boiler Fuel Measured Temp	Fuel SG	Comp.[3]	Fuel Flow	DB Measured Fuel Pressure	DB Measured Fuel Temp	Comp.[4]	Compensated Fuel Flow Rates		High Heating Value (HHV)	Average Total Heat Input	Average Fuel Gas Total Sulfur (Calculated as H2S)	Average NH3 Solution Injection During Test	Ratio (NH3 Solution Injection/Fuel Gas Total Sulfur)	Test Results			Emission Factors		
			Run Start	Boiler				Boiler	Duct Burner			DB	Boiler	Duct Burner						FPM	CPM	TPM	FPM	CPM	TPM
			Run Stop	Mscf	psig	deg F			Mscf	psig	deg F		Mscf	Mscf	Btu/Scf	MMBtu/hr	ppm	lb/hr	lb/hr / ppm	lb/hr	lb/hr	lb/hr	lb/MMBtu	lb/MMBtu	lb/MMBtu

[1] During run 1 of the compliance stack test completed on 1/28/2016 on Boiler 32, the inorganic rinse was combined with the organic rinse of the impingers. The sample was deemed invalid and an additional run was performed (i.e., run 4). Consistent with the report dated March 8, 2016, run 1 was not used in this analysis.
[2] Consistent with Boiler 33 compliance stack test completed on 10/11/2018, the analysis does not include run 3 due to a plant operation upset.
[3] The 3SPS Boiler fuel flow rates are measured using an orifice plate flow meters. Therefore, the flow rates have been compensated using Equation 1 and the constants below.
[4] The 3SPS Duct Burner fuel flow rates are measured using an vortex flow meters. Therefore, the flow rates have been compensated using Equation 2 and the constants below.
[5] Time periods (i.e., 10/11/2018 and 10/12/2018 tests) where the HHV and specific gravity could not be determined due to analyzer fault/malfunction have been substituted based on engineering judgement and best available data.

Flow Meter Compensation Factors

	Boiler Flow Meters	Duct Burner Flow Meters	Units
Temp Zero	459.69	459.69	R
Atm. Pressure	14.44	14.44	psi
Design Pressure	34.696	36.30	psi
Design Temp	549.69	539.69	R
Design SG	0.752	--	

Equation 1

For Orifice Plate flow meters:

$$Q_{c,Orifice} = Q_m \sqrt{\frac{(T_d)*(P_m)*(SG_d)}{(T_m)*(P_d)*(SG_m)}}$$

Where

$Q_{c,\ Orifice}$ is the compensated volume flow of the orifice plate meter
Q_m is the measured volume flow
T_d is the meter design absolute temperature (°R or °K)
T_m is the measured stream absolute temperature (°R or °K)
P_d is the (absolute) meter design pressure
P_m is the (absolute) measured stream pressure
SG_d is the meter design density (or specific gravity)
SG_m is the measured stream density (or specific gravity)

Equation 2

For Vortex flow meters:

$$Q_{c,Vortex} = Q_m\left(\frac{(T_d)*(P_m)}{(T_m)*(P_d)}\right)$$

Where

$Q_{c,\ Orifice}$ is the compensated volume flow of the orifice plate meter
$Q_{c,\ Vortex}$ is the compensated volume flow of the vortex meter
Q_m is the measured volume flow
T_d is the meter design absolute temperature (°R or °K)
T_m is the measured stream absolute temperature (°R or °K)
P_d is the (absolute) meter design pressure
P_m is the (absolute) measured stream pressure

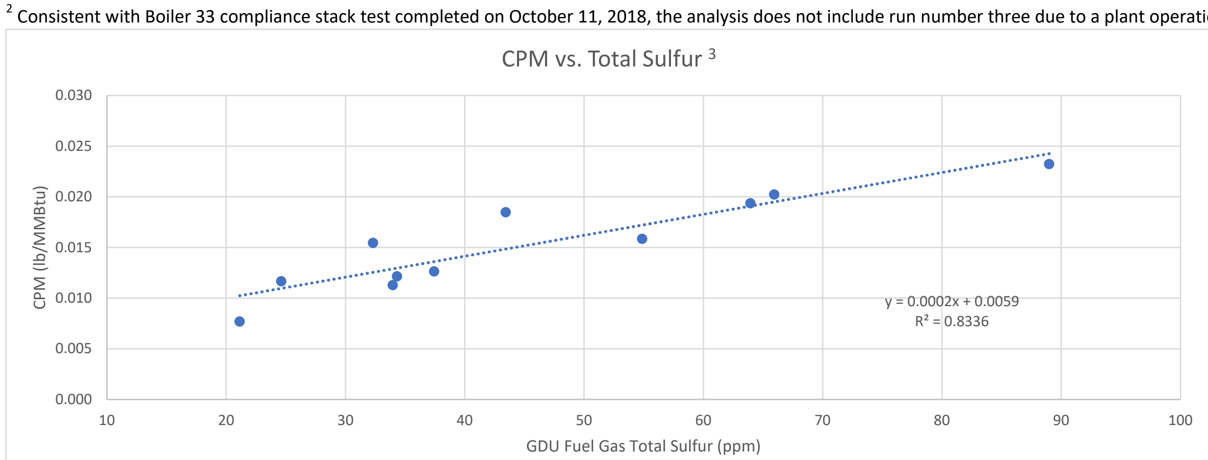
Appendix A: Emission Calculations
Statistical Analysis 2022

Source Name: BP Products North America, Inc. - Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394
Significant Permit Modification No.: 089-45450-00453
Reviewer: Aasim Noveer

Boiler	Test Date	Compensated Fuel Flow Rates		High Heat Value (HHV)	Heat Input	Average Fuel Gas Total Sulfur During Test (Calculated as H2S)	Average NH3 Solution Injection During Test	Ratio (NH3 Solution Injection/Fuel Gas Total Sulfur)	Emission Factors		
		Boiler	Duct Burner						FPM	CPM	TPM
		Mscf	Mscf	Btu/hr	MMBtu/hr	ppm	lb/hr	lb/hr / ppm	lb/MMBtu	lb/MMBtu	lb/MMBtu
Boiler 32 (SCR-on)	8/3/2015	511.6	40.7	942	519.9	43.4	283.3	6.5	0.0014	0.018	0.020
Boiler 36 (SCR-on)	8/5/2015	452.2	35.3	1,083	528.0	54.9	217.7	4.0	0.0015	0.016	0.017
Boiler 32 (SCR-on)	10/20/2015	444.9	34.2	1,033	494.7	64.0	205.1	3.2	0.0007	0.019	0.020
Boiler 32 (SCR-on) [1]	1/28/2016	424.5	35.3	1,080	496.7	65.9	236.1	3.6	0.0020	0.020	0.022
Boiler 36 (SCR-on)	11/2/2016	472.2	39.7	1,006	514.8	89.0	245.4	2.8	0.0019	0.023	0.025
Boiler 31 (SCR-on)	10/8/2018	524.5	41.1	942	532.6	37.4	108.5	2.9	0.0049	0.013	0.017
Boiler 32 (SCR-on)	10/9/2018	511.7	32.3	923	502.4	32.3	124.6	3.9	0.0044	0.015	0.020
Boiler 33 (SCR-on) [2]	10/11/2018	550.6	40.2	849	501.9	24.6	129.3	5.3	0.0063	0.012	0.018
Boiler 34 (SCR-on)	10/12/2018	581.4	42.1	849	529.6	21.1	129.8	6.1	0.0062	0.008	0.014
Boiler 36 (SCR-on)	4/16/2019	577.6	39.7	877	541.6	34.0	304.1	9.0	0.0014	0.011	0.013
Boiler 31 (SCR-on)	11/16/2021	629.1	52.6	808	550.8	34.3	153.9	4.5	0.0014	0.012	0.014

[1] During run one of the compliance stack test completed on January 28, 2016 on Boiler 32, the inorganic rinse was combined with the organic rinse of the impingers. The sample was deemed invalid and an additional run was performed (i.e., run four). Consistent with the report dated March 8, 2016, run one was not used in this analysis.

[2] Consistent with Boiler 33 compliance stack test completed on October 11, 2018, the analysis does not include run number three due to a plant operation upset.



Example monthly emission factor calculation based on linear regression formula	
Slope	0.00021
Y-Intercept	0.0059
Monthly Average Total Sulfur Content (ppm)	20
CPM Emission Factor (lb/MMBtu)	0.010

[3] The October 21, 2015 and November 1, 2016 tests were not included in the linear regression analysis as the ratio of ammonia injection to total sulfur was less than two.

Appendix A: Emission Calculations
Statistical Analysis 2022

Source Name: BP Products North America, Inc. - Whiting Business Unit
Source Address: 2815 Indianapolis Boulevard, Whiting, Indiana 46394
Significant Permit Modification No.: 089-45450-00453
Reviewer: Aasim Noveer

Boiler	Test Date	CPM lb/MMBtu
Boiler 32 (SCR-on)	8/3/2015	0.018
Boiler 36 (SCR-on)	8/5/2015	0.016
Boiler 32 (SCR-on)	10/20/2015	0.019
Boiler 32 (SCR-on)	1/28/2016	0.020
Boiler 36 (SCR-on)	11/2/2016	0.023
Boiler 31 (SCR-on)	10/8/2018	0.013
Boiler 32 (SCR-on)	10/9/2018	0.015
Boiler 33 (SCR-on)	10/11/2018	0.012
Boiler 34 (SCR-on)	10/12/2018	0.008
Boiler 36 (SCR-on)	4/16/2019	0.011
Boiler 31 (SCR-on)	11/16/2021	0.012
Standard Deviation (lb/MMBtu)		0.0045
Average (lb/MMBtu)		0.015
% Standard Deviation:		**30%**
Conditional Safety Factor (CSF)		**1.3**

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
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Eric J. Holcomb
Governor
Brian C. Rockensuess
Commissioner

February 14, 2023

Caleb Gingerich
BP Products North America, Inc., - Whiting Business Unit
2815 Indianapolis Blvd
Whiting, IN 46394

Re: Public Notice
BP Products North America, Inc., -
Whiting Business Unit
Permit Level: Title V Significant Permit Modification
Permit Number: 089-45450-00453

Dear Mr. Gingerich:

Enclosed is the Notice of 30-Day Period for Public Comment for your draft air permit.

Our records indicate that you are the contact person for this application. However, if you are not the appropriate person within your company to receive this document, please forward it to the correct person. The Notice of 30-Day Period for Public Comment has also been sent to the OAQ Permits Branch Interested Parties List and, if applicable, your Consultant/Agent and/or Responsible Official/Authorized Individual.

The preliminary findings, including the draft permit, technical support document, emission calculations, and other supporting documents, **are available electronically at**:

IDEM's online searchable database: http://www.in.gov/apps/idem/caats/ . Choose Search Option **by Permit Number**, then enter permit 45450

and

IDEM's Virtual File Cabinet (VFC): https://www.IN.gov/idem. Enter VFC in the search box, then search for permit documents using a variety of criteria, such as Program area, date range, permit #, Agency Interest Number, or Source ID.

The Public Notice period will begin the date the Notice is published on the IDEM Official Public Notice website. Publication has been requested and is expected within 2-3 business days. You may check the exact Public Notice begins and ends date here: https://www.in.gov/idem/public-notices/

Please note that as of April 17, 2019, IDEM is no longer required to publish the notice in a newspaper.

OAQ has submitted the draft permit package to the Whiting Public Library, 1735 Oliver St in Whiting, IN 46394. 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 draft permit 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 Aasim Noveer, 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 1243 or dial (317) 234-1243.

Sincerely,

Tara Champion

Tara Champion
Permits Branch
Office of Air Quality

Enclosures
PN Applicant Cover Letter access via website 8/10/2020

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Governor

Brian C. Rockensuess
Commissioner

February 14, 2023

To: Whiting Public Library

From: Jenny Acker, 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: 089-45450-00453

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
- 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 updated 4/2019

Indiana Department of Environmental Management
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Eric J. Holcomb
Governor

Brian C. Rockensuess
Commissioner

Notice of Public Comment

February 14, 2023
BP Products North America, Inc., - Whiting Business Unit
089-45450-00453

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 posted on IDEM's Public Notice website at https://www.in.gov/idem/public-notices/.

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 Joanne Smiddie-Brush with the Air Permits Administration Section at 1-800-451-6027, ext. 3-0185 or via e-mail at JBRUSH@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 Letter 2/28/2020

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Commissioner

AFFECTED STATE NOTIFICATION OF PUBLIC COMMENT PERIOD
DRAFT INDIANA AIR PERMIT

February 14, 2023

A 30-day public comment period has been initiated for:

Permit Number: **089-45450-00453**
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 1/9/2017

Mail Code 61-53

IDEM Staff	TCHAMPIO 2/14/2023 BP Products North America - Whiting Business Unit 089-45450-00453 draft			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**	

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		Caleb Gingerich BP Products North America - Whiting Business Unit 2815 Indianapolis Blvd Whiting IN 46394 (Source CAATS)									
2		Donnie Brown Vice President of Operations BP Products North America - Whiting Business Unit 2815 Indianapolis Blvd Whiting IN 46394 *(RO CAATS)*									
3		East Chicago City Council 4525 Indianapolis Blvd East Chicago IN 46312 *(Local Official)*									
4		Hammond City Council and Mayors Office 5925 Calumet Ave Hammond IN 46320 *(Local Official)*									
5		Mr. Tim Maloney Hoosier Environmental Council 3951 N Meridian St, Ste 100 Indianapolis IN 46208 *(Affected Party)*									
6		Whiting City Council and Mayors Office PO Box 591 Whiting IN 46394 *(Local Official)*									
7		Craig Hogarth 7901 W Morris St Indianapolis IN 46231 *(Affected Party)*									
8		Whiting Public Library 1735 Oliver St Whiting IN 46394-1794 *(Library)*									
9		Lake County Board of Commissioners 2293 N Main St, Bldg A, 3rd Floor Crown Point IN 46307 *(Local Official)*									
10		Anthony Copeland 2006 E 140th St East Chicago IN 46312 *(Affected Party)*									
11		Barbara G Perez 506 Lilac St East Chicago IN 46312 *(Affected Party)*									
12		Mr. Robert Garcia 3733 Parrish Ave East Chicago IN 46312 *(Affected Party)*									
13		Joe Carroll Bloomberg News 111 S Wacker Dr, Ste 4950 Chicago IL 60606 (Affected Party)									
14		Ms. Karen Kroczek 8212 Madison Ave Munster IN 46321-1627 *(Affected Party)*									
15		Rosemarie Cazeau Illinois Attorney General Office 69 W Washington St, 18th floor Chicago IL 60602 *(Affected Party)*									

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FACSIMILIE OF PS Form 3877

Mail Code 61-53

IDEM Staff	TCHAMPIO 2/14/2023 BP Products North America - Whiting Business Unit 089-45450-00453 draft			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**	

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		Environmental Law and Policy Center 35 E Wacker Dr, #1600 Chicago IL 60601 (Affected Party)									
2		Joseph Hero 11723 S Oakridge Dr St. John IN 46373 *(Affected Party)*									
3		Mr. Thomas Frank 1616 E 142nd St East Chicago IN 46312 *(Affected Party)*									
4		Tom Anderson Save the Dunes 444 Barker Rd Michigan City IN 46360 *(Affected Party)*									
5		Sierra Club, Inc. - Hoosier Chapter 1100 W 42nd St, Ste 140 Indianapolis IN 46208 *(Affected Party)*									
6		Sunny Lee Environmental Integrity Project 1000 Vermont Ave NW, Ste 1100 Washington DC 20005 *(Affected Party)*									
7		Gary City Council 401 Broadway #209 Gary IN 46402 *(Local Official)*									
8		City of Gary Dept. of Environmental Affairs 401 Broadway, Ste 304 Gary IN 46402 *(Local Official)*									
9		Mr. Larry Davis 268 S 600 W Hebron IN 46341 *(Affected Party)*									
10		Tom Soulis 3646 Ridge Rd Highland IN 46322 *(Affected Party)*									
11		Susan Eleuterio 3646 Ridge Rd Highland IN 46322 *(Affected Party)*									
12		Kay Nelson 6100 Southport Rd Portage IN 46368 *(Affected Party)*									
13		George Smolka 337 S Griffith Blvd Griffith IN 46319 (Affected Party)									
14		Michael C Repay Lake County Board of Commissioners 2293 N Main St, Bldg A, 3rd Floor Crown Point IN 46307 *(Affected Party)*									
15		Kristina Kantar Hammond City Council Attorney 5925 Calumet Ave Hammond IN 46320 *(Affected Party)*									

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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Mail Code 61-53

IDEM Staff	TCHAMPIO 2/14/2023 BP Products North America - Whiting Business Unit 089-45450-00453 draft			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**	

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		Jeff News-Dispatch 422 Franklin St Michigan City IN 46360 (Affected Party)									
2		Lake County Health Department 2900 W 93rd Ave Crown Point IN 46307 *(Health Department)*									
3		Menards 6300 Mississippi St Merrillville IN 46410 *(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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