Special Conditions

Permit Number 6819A

1. This permit authorizes emissions only from those points listed in the attached table entitled "Emission Sources - Maximum Allowable Emission Rates" (MAERT) and the facilities covered by this permit are authorized to emit subject to the emission rate limits on that table and other operating requirements specified in the special conditions.

    A. Non-fugitive emissions from relief valves, safety valves, or rupture discs of gases containing volatile organic compounds (VOC) at a concentration of greater than 1 percent are not authorized by this permit unless authorized on the MAERT. Any releases directly to atmosphere from relief valves, safety valves, or rupture discs of gases containing VOC at a concentration greater than 1 weight percent are not consistent with good practice for minimizing emissions with exception of safety relief valves that discharge to the atmosphere as a result of fire, malfunction, or failure of utilities provided that (except pilot-operated relief valves): (a) each valve is equipped with a rupture disc upstream; (b) a pressure gauge is installed between the relief valve and rupture disc to monitor disc integrity; and (c) all leaking discs are replaced at the earliest opportunity but no later than the next process shutdown.

Federal Applicability

2. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on Standards of Performance for New Stationary Sources promulgated in Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):

    A. Subpart A, General Provisions

    B. Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

    C. Subpart J, Standards of Performance for Petroleum Refineries

    D. Subpart Ja, Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After May 14, 2007

    E. 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 **(03/23)**

    F. 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 **(03/23)**

    G. Subpart XX, Standards of Performance for Bulk Gasoline Terminals

    H. 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

    I. Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006

3. These facilities shall comply with all applicable requirements of the U.S. EPA regulations on National Emission Standards for Hazardous Air Pollutants in 40 CFR Part 61:

A. Subpart A, General Provisions

B. Subpart BB, National Emission Standard for Benzene Emissions from Benzene Transfer Operations

C. Subpart FF, National Emission Standard for Benzene Waste Operations

4. These facilities shall comply with all applicable requirements of the U.S. EPA regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories in 40 CFR Part 63: **(09/24)**

   A. Subpart A, General Provisions

   B. Subpart F, National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry

   C. Subpart G, National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater

   D. Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks

   E. Subpart Y, National Emission Standards for Marine Tank Vessel Loading Operations

   F. Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries

   G. Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units

   H. Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

   I. Subpart GGGGG, National Emission Standards for Hazardous Air Pollutants: Site Remediation

Truck Loading

5. The tank truck loading rack is limited to a gasoline throughput of 96,000 gal/hr and 10,950,000 bbl/yr and a distillate throughput of 96,000 gal/hr and 4,380,000 bbl/yr. Records of product throughput shall be maintained.

   A. Emissions from loading VOC with a vapor pressure equal to or greater than 0.5 pounds per square inch, absolute (psia) at maximum loading temperature shall be routed to the vapor combustion unit using a vacuum-assisted vapor collection system. Loading of VOC with a vapor pressure equal to or greater than 0.5 psia at maximum loading temperature shall be immediately stopped if the vacuum-assisted vapor collection system is inoperative. Loading of VOC with a vapor pressure equal to or greater than 0.5 psia at maximum loading temperature shall not start or re-start until the vacuum-assisted vapor collection system is operational.

   B. Emissions from loading VOC with a vapor pressure less than 0.5 psia at maximum loading temperature are not required to be controlled and may occur at the Truck Loading Rack, Emission Point Number (EPN) TR-101 or at the Truck Vapor Combustion Unit (EPN VCU).

Marine Loading

6. Marine loading of product from these facilities shall not exceed the following rates:

Type of Vessel Loaded	Product Loaded	Loading Rate (bbl/hr)	Loading Rate (bbl/yr)
Ships Ocean Barge Shallow Barge	Toluene	6,000	7,300,000
	Benzene	6,000	4,000,000
	Xylene	10,000	18,250,000
	Light Straight Run (Mixed Pentanes)	5,000	4,000,000
	Gasolines/blendstocks	10,000	6,935,000
	Naphthas	10,000	8,030,000
	Cumene/pseudocumene	10,000	7,000,000
Ships Ocean Barges	Crude Oil	9,000	17,000,000
Shallow Barges	Crude Oil	6,000	

A. Each barge and ship loading dock shall utilize submerged fill. The collected vapors from the liquids in the table above and any VOC with a true vapor pressure equal to or greater than 0.50 psia from barge and/or ship vessel loading at Dock Nos. 8, 9 and 10 shall be collected and routed to the marine vapor control system (EPN VCS-1).

B. A pressure-monitoring device shall be installed at the common point of the vapor collection system between the barge/ship connection and the vacuum blowers/compressors to continuously measure pressure in the marine loading vapor collection system during loading of materials with a maximum true vapor pressure equal to or greater than 0.50 psia. The vapor collection piping shall be all welded between the Dock Safety Unit discharge flange and the vacuum blower liquid knockout pot inlet flange. A blower/compression system shall be installed which will produce a vacuum in the loading system. The average pressure on the vapor collection system shall be maintained at a negative pressure of at least 1.5 inches water column during a loading period of material with a maximum true vapor pressure equal to or greater than 0.50 psia. The vacuum shall be recorded every fifteen minutes. In the event the pressure monitoring device is not functioning properly, barge loading operations and ship loading operations for material with a maximum true vapor pressure equal to or greater than 0.50 psia requiring use of the vapor combustor as an emission control device shall cease within two hours of malfunction. Additional loading requiring use of the vapor combustor shall not begin until the problems with the pressure monitoring device(s) are repaired.

   Quality assured (or valid) data must be generated when barges and ships are loaded with material with a maximum true vapor pressure equal to or greater than 0.50 psia at this dock. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the barge and ship loading dock operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

C. All loading lines (hoses) and connectors shall be visually inspected for any defects prior to hookup. Lines and connectors that are visibly damaged shall be removed from service. Operations shall cease immediately upon detection of any liquid leaking from the lines or connections. Flanged connections shall be used for all loading operations. The following actions shall be taken prior to removing loading lines/hoses from marine vessels and shore facilities.

(1) After the transfer is complete, the loading line/hose shall be isolated at the connection to the shore piping. The loading line/hose shall be vented at the shore piping and shall be gravity drained or pressured into the marine vessel per the site operating procedure.

(2) The loading line/hose may be disconnected from the shore and/or marine vessel piping after the liquid has been removed to the extent possible by gravity draining to the vessel being loaded. If it is necessary to further empty the line/hose, any residual liquid in the line/hose shall be immediately drained directly into a covered sump. If the line/hose is not emptied, the open end(s) of the line/hose shall be immediately capped, plugged, or blinded to prevent leakage.

(3) After the loading line/hose has been removed from the vessel, the vapor return line shall be immediately isolated.

The actions shall be documented as part of the loading procedure.

D. The permit holder shall maintain and update monthly an emissions record which includes calculated emissions of VOC from all marine loading operations over the previous rolling 12-month period. The record shall include the loading spot, control method used, quantity loaded in gallons, name of the liquid loaded, vapor molecular weight, liquid temperature in degrees Fahrenheit, liquid vapor pressure at the liquid temperature in psia, liquid throughput for the previous month and rolling 12 months to date. Records of VOC temperature are not required to be kept for liquids loaded from unheated tanks which receive liquids that are at or below ambient temperatures. Loading emissions shall be calculated using the methods used to determine the MAERT limits in the permit amendment application, PI-1 dated December 12, 2012. Sample calculations from the application shall be attached to a copy of the permit at the refinery.

Marine Vapor Combustor

7. The marine vapor combustor (EPN VCS-1) shall be designed and operated in accordance with the following requirements: **(1/24)**

A. The marine vapor combustor (EPN VCS-1) shall achieve a waste gas destruction efficiency at a minimum of 99.5% on an hourly average in the vapor combustor firebox while controlling exhaust vapors from VOC liquid loading. The six-minute average temperature shall be maintained above the minimum one-hour average temperature maintained during the last satisfactory stack test. This requirement shall not apply when waste gas is not being directed to the VCU.

B. The temperature measurement device shall reduce the temperature readings to an averaging period of 6 minutes or less and record it at that frequency. The temperature monitor shall be installed, calibrated, or have a calibration check performed at least annually, and maintained in according to the manufacturer’s specifications. The device shall have an accuracy of the greater of ±2 percent of the temperature being measured expressed in degrees Celsius or ±2.5ºC. During barge and/or ship loading activities of chemicals that require VOC abatement, the average vapor combustor firebox temperature shall not fall below 1447ºF.

C. Quality assured (or valid) data must be generated when barges and ships are loaded with VOC liquid with a true vapor pressure equal to or greater than 0.50 psia at docks 8, 9 and 10, Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the barge and ship loading docks 8, 9 and 10 operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgement and the methods used recorded.

The vapor combustor shall be operated with no visible emissions and have a constant pilot flame during all times waste gas could be directed to it. The pilot flame shall be continuously monitored by a flame scanner or a thermocouple. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to and shall be calibrated or have a calibration check performed at a frequency in accordance with, the manufacturer's specifications.

8. Reserved. **(03/23)**

Heaters

9. The following heater requirements shall be met:

A. Nitrogen oxides (NO_x), carbon monoxide (CO), and ammonia emissions from the Light Ends Unit (LEU) Hot Oil Heater (EPN LEUHOH) shall not exceed the following rates/concentrations (concentrations are corrected to 3 percent oxygen).

Pollutant	Emission Limit
NO_x	0.01 lb/MMBtu (hourly average)
NO_x	0.0075 lb/MMBtu (365-day rolling average)
Ammonia	10 ppmvd (hourly average)
CO	50 ppmvd (hourly average)

Except when bypassing for maintenance as specified in Special Condition No. 50, the LEU Hot Oil Heater exhaust shall be directed to a combustion catalyst and SCR.

The NO_x and CO limits above shall not apply when the SCR and combustion catalyst systems are bypassed for maintenance as specified in Special Condition No. 50.

The limits above shall not apply when the LEU Hot Oil Heater fires below 20 percent of its rated firing capacity (low load), so long as the emissions from the heater remain below the allowable emission rates on the MAERT. Low load operating conditions shall be limited to 876 hours per rolling 12-month period.

B. NO_x, CO, and ammonia emissions from the NHT Charge Heater and the CCR Hot Oil Heater common exhaust (EPN JJ-4) shall not exceed the following rates/concentrations (concentrations are corrected to 3 percent oxygen).

Pollutant	Emission Limit
NO_x	0.01 lb/MMBtu (hourly average)
NO_x	0.0075 lb/MMBtu (365-day rolling average)
Ammonia	10 ppmvd (hourly average)
CO	50 ppmvd (hourly average)

The NO_x limits above shall not apply when the SCR system is bypassed for maintenance as specified in Special Condition No. 50.

The limits of each heater above shall not apply when either heater fires below 20 percent of its firing rate capacity (low load), so long as the combined emissions from the two heaters remain below the emission limits listed in MAERT. Low load operating conditions shall be limited to 876 hours per rolling 12-month period, per heater.

C. Nitrogen oxides (NO_x), carbon monoxide (CO), and ammonia emissions from the CCR Auxiliary Charge Heater (EPN JJ-7) shall not exceed the following rates/concentrations (concentrations are corrected to 3 percent oxygen).

Pollutant	**Emission Limit**
NO_x	0.01 lb/MMBtu (hourly average)
NO_x	0.0075 lb/MMBtu (365-day rolling average)
Ammonia	10 ppmvd (hourly average)
CO	50 ppmvd (hourly average)

The NO_x and CO limits above shall not apply when the SCR system is bypassed for maintenance as specified in Special Condition No. 50.

The limits above shall not apply when the CCR Auxiliary Charge Heater (EPN JJ-7) fires below 20 percent of its rated firing capacity (low load), so long as the emissions from the heater remain below the allowable emission rates on the MAERT. Low load operating conditions shall be limited to 876 hours per rolling 12-month period.

10. The LEU Hot Oil Heater shall be fired with natural gas and LPG Treating off-gas containing no more than 5 grains of total sulfur per 100 dry standard cubic feet (dscf) on an hourly average and no more than 0.5 grains/100 dscf on an annual average. The natural gas shall be continuously monitored for total sulfur content.

    The NHT Charge Heater and the CCR Hot Oil Heater shall be fired with fuel gas containing no more than 7.2 grains of total sulfur per 100 dscf on an hourly average and no more than 2 grains S/100 dscf on an annual average. The fuel gas shall be continuously monitored for total sulfur at the mix drum for the CCR #1 Fuel System.

    The CCR Auxiliary Charge Heater (EPN JJ-7) shall be fired with natural gas and/or refinery fuel gas containing no more than 5 grains of total sulfur per 100 dry standard cubic feet (dscf) on an hourly average and no more than 0.64 grains/100 dscf on an annual average. The refinery fuel gas shall be continuously monitored for total sulfur content.

11. The permit holder shall install and operate a natural gas fuel flow meter for the LEU Hot Oil Heater, and a fuel gas flow meter for the CCR Hot Oil Heater and the CCR Auxiliary Charge Heater to measure the gas fuel usage for each heater. The monitored data shall be reduced to an hourly average flow rate at least once every day, using a minimum of four equally spaced data points from each one-hour period. Each fuel flow monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications or at least annually, whichever is more frequent, and shall be accurate to within 5 percent. In lieu of monitoring fuel flow, the permit holder may monitor stack exhaust flow using the flow monitoring specifications of 40 Code of Federal Regulations (CFR) Part 60, Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A. The amount of off-gas fired by the LEU Hot Oil Heater shall be estimated using engineering calculations in lieu of monitoring.

12. The NO_x emissions in the stack gases from the following combustion sources (Facility Identification

Numbers [FINs]) shall not exceed the lb/MMBtu values listed below. The averaging period shall be hourly, unless otherwise specified:

EPN	FIN	Description	Maximum Heat Specific EF (lb/MMBtu, LHV)
A-203	42BA1	Crude Heater	0.07
A-204	42BA3	Vacuum Heater	0.08
DDS-HTRSTK	56BA1*	DDS Charge Heater	0.036 (HHV) **(03/23)**
DDS-HTRSTK	56BA2*	DDS Fractionator Reboiler	0.045 (HHV)
KK-3	37BA1	Distillate Hydrotreater (DHT) Charge Heater	0.06
KK-3	37BA2*	DHT Stripper Reboiler	0.06
LSGHTR	47BA1*	LSG Hot Oil Heater	0.045 (HHV)
MX-1	54BA1*	MX Unit Hot Oil Heater	0.07
R-201	43BF1	Crude Boiler	0.08
*FINs updated Note: FIN – Facility Identification Number LHV – Low Heating Value HHV – High Heating Value EF – Emission Factor			

The NO_x limit of each heater above shall not apply when that heater fires below 20 percent of its firing rate capacity (low load), so long as NO_x emissions remain below the NO_x allowable emission rates. Low load operating conditions shall be limited to 876 hours per year per heater.

13. There shall be no visible emissions for periods exceeding five minutes over any two-hour period from EPNs JJ-7, JJ-4, A-203, A-204, DDS-HTRSTK, KK-3, LSGHTR, MX-1, and R-201. The opacity limitation shall be determined by using the procedures specified in Title 40 Code of Federal Regulations § 60.11(b) [40 CFR § 60.11(b)] upon request of the Texas Commission on Environmental Quality (TCEQ) Executive Director or TCEQ representatives.

14. Except as provided for in the special conditions of this permit, the fuel for any heater, boiler, turbine, flare pilot, or flare sweep is limited to either natural gas, refinery fuel gas, or a combination of natural gas and refinery fuel gas.

    Upon request by the Executive Director of the TCEQ or the Regional Administrator of the U. S. EPA or any local air pollution control agency having jurisdiction, the holder of this permit shall provide a sample and/or analysis of the fuel utilized or shall allow air pollution control agency representatives to obtain a sample for analysis.

    A. For the following combustion sources, the total sulfur content shall not exceed 5 gr S/100 dscf on a rolling three-hour average or exceed 0.6 gr S/100 dscf on an annual average basis.

EPN	FIN	Description
A-203	42BA1	Crude Heater
A-204	42BA3	Vacuum Heater
LSGHTR	47BA1*	LSG Hot Oil Heater

MX-1	54BA1*	MX Unit Hot Oil Heater
KK-3	37BA1	DHT Charge Heater
KK-3	37BA2*	DHT Stripper Reboiler
R-201	43BF1	Mid Crude Boiler
DDS-HTRSTK	56BA1*	DDS Charge Heater
DDS-HTRSTK	56BA2*	DDS Fractionator Reboiler
*FINs updated		

For the sources listed above, the fuel gas shall be continuously monitored for total sulfur content at the mix drum of the Mid Plant fuel system.

B. The fuel for the FCCU CO boiler (EPN AA-4) is limited to natural gas, refinery fuel gas, FCCU regenerator off-gas, or a combination of any of the three fuels. The H_2S content of the refinery fuel gas or natural gas stream shall not exceed 0.1 gr/dscf on a rolling 3-hr average.

15. For the following combustion sources, particulate matter (PM) less than 10 microns in diameter emissions shall not exceed the following, based on a daily average, when fired at maximum firing capacity. The following emission limits are based on the Higher Heating Value (HHV) of the fuel:

EPN	FIN	Description	Emission Limit
A-203	42BA1	Crude Heater	0.0045 lb PM_{10}/MMBtu
A-204	42BA3	Vacuum Heater	0.0045 lb PM_{10}/MMBtu
R-201	43BF1	Boiler	0.0045 lb PM_{10}/MMBtu

16. The permit holder shall install, calibrate, and maintain a continuous emission monitoring system (CEMS) to measure and record the in-stack concentration of pollutants listed from the combustion sources listed in Special Condition No. 17.

A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60), Appendix B. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Office of Air, Air Permits Division for requirements to be met.

(1) For EPNs JJ-4 and LEUHOH, in lieu of the relative accuracy requirement in PS 2, an alternative relative accuracy requirement of ±2.0 ppmv from the reference method mean value is allowed. This alternative relative accuracy requirement is not applicable in situations where the reference method is within 2 ppmv of the equivalent limit presented in SC 9. **(06/25)**

B. Section 1 below applies to sources subject to the quality-assurance requirements of 40 CFR Part 60, Appendix F; section 2 applies to all other sources:

(1) The permit holder shall assure that the CEMS meets the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Relative accuracy exceedances, as specified in Special Condition 16.A.(1) or in 40 CFR Part 60, Appendix F, Section 5.2.3 and any CEMS downtime shall be reported to the appropriate TCEQ Regional Manager, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of

the appropriate TCEQ Regional Manager. Downtime is not considered to include periods when the CEMS is operational, but the 24-hour span drift exceeds the allowable amounts. **(06/25)**

(2) The system shall be zeroed and spanned daily, and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B, or as specified by the TCEQ if not specified in Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days, unless the monitor is required by a subpart of NSPS or NESHAPS, in which case zero and span shall be done daily without exception.

Each monitor shall be quality-assured at least quarterly using Cylinder Gas Audits (CGA) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, Section 5.1.2, with the following exception: a relative accuracy test audit (RATA) is not required once every four quarters (i.e., four successive quarterly CGA may be conducted). An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur no closer than two months.

All CGA exceedances of ±15 percent accuracy indicate that the CEMS is out of control.

C. The monitoring data shall be reduced to hourly average concentrations at least weekly, using a minimum of four equally spaced data points from each one-hour period except as specified in §60.13(h)(2)(iii) during maintenance and quality assurance activities. **(07/24)**

The individual average concentrations shall be reduced to units of pounds per hour and pounds per million BTU at least once every calendar quarter as follows:

The measured hourly average concentration from the CEMS shall be multiplied by the exhaust flow rate as measured directly, or determined by monitoring fuel flow, stack oxygen concentration, and the fuel gas heating value, to determine the hourly emission rate. The emission rate and fuel gas flow and heating value shall be used to determine the lb NO_x/MMBtu heat input.

D. All monitoring data and quality-assurance data shall be maintained by the permit holder. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

E. The appropriate TCEQ Regional Office shall be notified at least 30 days prior to any required RATA in order to provide them the opportunity to observe the testing.

F. Quality-assured (or valid) data must be generated when the heater is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the heater operated over the previous rolling 12-month period. The data availability shall be calculated as the total fired unit operating hours for which quality assured data was recorded divided by the total fired unit operating hours. The measurements missed shall be estimated using engineering judgment and the methods used recorded. Options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ Regional Manager.

17. Special Condition No. 16 shall apply to the following sources and pollutants:

EPN	FIN*	Source	Pollutant/Diluent Monitored

LEUHOH	42BA5	LEU Hot Oil Heater	NO_x, CO, O_2
JJ-4	39BA3900	NHT Charge Heater	NO_x, CO, O_2
JJ-4	39BA3901	CCR Hot Oil Heater	NO_x, CO, O_2
A-203	42BA1	Crude Heater	NO_x, CO, O_2
A-204	42BA3	Vacuum Heater	NO_x, CO, O_2
AA-4	01BF102	FCCU CO Boiler Off-Gas Scrubber	NO_x, SO_2 (per NSPS), O_2
AA-4	01BF102	FCCU CO Boiler Outlet Duct	CO (per NSPS) and O_2
LSGHTR	47BA1	LSG Hot Oil Heater	NO_x (per NSPS), CO, O_2
R-201	43BF1	Crude Boiler	NO_x (per NSPS), CO, O_2
JJ-7	CCRAUXHTR	CCR Auxiliary Charge Heater	NO_x, CO, O_2

18. The permit holder shall continuously monitor ammonia emissions from the heater SCR systems (EPNs LEUHOH, JJ-4, and JJ-7) using one of the following methods:

A. Install and operate two NO_x CEMS, one located upstream of the SCR system and the other located downstream of the SCR system, which are used in association with ammonia injection rate and the following calculation procedure to estimate ammonia slip.

Ammonia slip, ppmvd = (a – (b x c / 1,000,000)) x 1,000,000 / b) x d

where:

a = ammonia injection rate (lb/hr)/17 (lb/lb-mole);

b = dry exhaust gas flow rate (lb/hr)/29 (lb/lb-mole);

c = change in measured NO_x concentration, ppmvd, across catalyst; and

d = correction factor.

The correction factor shall be derived during compliance testing by comparing the measured and calculated ammonia slip. The ammonia injection rate and exhaust gas flow rate shall be recorded at least every 15 minutes and be recorded as hourly averages. Each flow monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, or at least annually, whichever is more frequent, and shall be accurate to within 2 percent of span or 5 percent of the design value.

B. Install and operate a dual stream system of NO_x CEMS at the exit of the SCR system. One of the exhaust streams would be routed, in an unconverted state, to one NO_x CEMS and the other exhaust stream would be routed through a NH_3 converter to convert NH_3 to NO_x and then to a second NO_x CEMS. The NH_3 slip concentration shall be calculated from the delta between the two NO_x CEMS readings (converted and unconverted).

All CEMS specified in A and B of this condition must meet the requirements of Special Condition No. 16. Quality-assured (or valid) data must be generated when gas is directed to the SCR system. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time that gas is directed to the SCR system over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

C. Install an ammonia continuous monitoring system (CMS) that complies with the following requirements or an alternative as approved by TCEQ.

(1) The ammonia analyzer (“the analyzer”) shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified below.

(2) An initial performance test to verify accuracy of the analyzer. The initial performance test shall be performed within 60 days of achieving maximum production rate at which either of the affected facilities will be operated, but not later than 180 days after initial startup of either such facility. Any analyzer downtime shall be reported to the appropriate TCEQ Regional Manager, and necessary corrective action shall be taken.

(3) The permit holder shall assure that the analyzer meets the applicable quality-assurance requirements specified below. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Manager. Each monitor shall be quality-assured at least quarterly by inspecting the transmission reading on the analyzer. If the transmission reading falls below 60%, then FHR will clean the cell wedge windows per manufacturer instructions.

(4) The permit holder shall perform a calibration check of the analyzer every 2 years using the calibration verification kit and the specific instructions provided by the manufacturer.

(5) The monitoring data shall be reduced to hourly average concentrations at least weekly, using a minimum of four equally spaced data points from each one-hour period except as specified in §60.13(h)(2)(iii) during maintenance and quality assurance activities. The individual average concentrations shall be reduced to units of pounds per hour at least once every calendar quarter as follows: **(07/24)**

(a) The measured hourly average concentration from the analyzer shall be multiplied by the exhaust flow rate as measured directly or determined by monitoring fuel flow and stack oxygen concentration to determine the hourly emission rate.

(6) All monitoring data and quality-assurance data shall be maintained by the permit holder. The data from the analyzer may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

(7) Quality-assured (or valid) data must be generated when the ammonia injection system is operating. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the ammonia injection system operated over the previous rolling 12-month period. The data availability shall be calculated as the total ammonia injection system operating hours for which quality assured data was recorded divided by the total ammonia injection system operating hours. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

19. The following requirements apply to capture systems for the marine vapor combustor (EPN VCS-1), and SCR systems for the hot oil heaters (EPNs LEUHOH, JJ-4, and JJ-7).

A. Conduct a once a month visual, audible, and/or olfactory inspection of the capture system to verify there are no leaking components in the capture system.

B. For the vapor combustor, the following may be completed in lieu of the monthly inspection specified in part A. Once a year, verify the capture system is leak-free by inspecting in accordance with 40 CFR Part 60, Appendix A, Test Method 21. Leaks shall be indicated by an instrument reading greater than or equal to 500 ppmv above background.

C. The control device shall not have a bypass, or if there is a bypass for the control device, comply with one of the following requirements:

(1) Install a flow indicator that records and verifies zero flow at least once every fifteen minutes immediately downstream of each valve that if opened would allow a vent stream to bypass the control device and be emitted, either directly or indirectly, to the atmosphere;

(2) Install a position indicator on the bypass that records and verifies the closed position (at least once every fifteen minutes) of each stack damper that, if opened, would allow a vent stream to bypass the SCR system of a hot oil heater and be emitted, either directly or indirectly, to the atmosphere; or

(3) Once a month, inspect the valves, verifying the position of the valves and the condition of the car seals prevent flow out the bypass.

A deviation shall be reported if the monitoring or inspections indicate bypass of the control device except as allowed under Special Condition No. 50.

D. The date and results of each inspection performed shall be recorded. If the results of any inspection are not satisfactory, the deficiencies shall be recorded and the permit holder shall promptly take necessary corrective action, recording each action with the date completed.

Fluid Catalytic Cracking Unit (FCCU) Process Requirements

20. Opacity:

A. The opacity of emissions from the FCCU scrubber stack shall not exceed 15 percent averaged over a six-minute period. The holder of this permit shall create and maintain records demonstrating compliance with the opacity standard.

B. The holder of this permit shall operate the FCCU wet gas scrubber in accordance with the specifications outlined in EPA’s March 5, 2008, West FCCU Opacity Alternative Monitoring Request approval for 40 CFR Part 60 Subpart J.

FHR will maintain at least two out of the three parameters listed below within proposed specifications

- L/G ratio shall be maintained at 0.032 gal/dscf or greater on an hourly basis;
- Differential pressure across each venture at 23.69 psid or greater on an hourly basis;
- Scrubber liquid pH shall be maintained at 6.41 or greater on an hourly basis

Should two out of three parameters above deviate from the range above, FHR will have a certified opacity reader check and record the FCCU scrubber stack exhaust opacity once per hour. The certified opacity reader will continue hourly opacity checks until at least two of the three parameters return within specification or until opacity readings cannot be recorded.

A deviation to the opacity requirements of NSPS Subpart J will be assumed to occur for each hour during which two or more of the parameters listed above deviate from the range and during which a certified opacity reader records an opacity reading greater than 30%. If a certified opacity reader cannot obtain an opacity reading during a potential deviation situation, then an opacity deviation will be assumed to occur from the time of the last opacity validation to the time that opacity can again be validated. Opacity validation includes certified opacity readings or maintaining at least two out of the parameters within the ranges above.

21. The maximum allowable concentrations of the following pollutants in the FCCU scrubber stack are given below:

Pollutant	Concentration Limit
CO	500 ppmvd (hourly*) 50 ppmvd (annual**)
NO_x	550 ppmvd @ 0% O_2 (hourly*) 93.0 ppmvd @ 0% O_2 (annual**)
Sulfur dioxide (SO_2)	250 ppmvd @ 0% O_2 (hourly*) 50 ppmvd @ 0% O_2 (7-day average***) 25 ppmvd @ 0% O_2 (annual**)
Ammonia	25 ppmvd (hourly*) 15 ppmvd (annual**)
* Hourly – averaged over one-hour period ** Annual – averaged over a rolling 365-day period *** 7-day average – averaged over a 7-day period	

An ambient oxygen concentration of 20.9 percent shall be used when correcting emissions to zero percent oxygen.

22. The FCCU scrubber stack is subject to the following limitations in terms of the coke burn rate:

A. Emissions from the FCCU scrubber stack shall not exceed 1.0 lb of PM per 1,000 lbs of coke burn-off averaged over a one-hour period.

An annual PM performance test shall be conducted on the FCCU scrubber stack using the applicable test methods in 40 CFR 60.106. PM performance tests shall be conducted within 12 calendar months of the prior PM performance test, or sooner if FHR wishes to do so. FHR shall operate at a coke burn rate no more than 5% greater than the coke burn rate during the prior PM performance test.

B. Emissions from the FCCU scrubber stack shall not exceed 0.43 lb of hydrogen cyanide (HCN) per 1,000 lbs. of coke burn-off averaged over a one-hour period.

Stack sampling for HCN from the FCCU scrubber stack shall be performed to meet requirements of 40 CFR 63 Subpart UUU. Initial stack sampling was performed in January 2017 using Test Method ASTM D6348-03. This meets the requirements for one-time performance testing for HCN required by Subpart UUU 63.1571(a)(6).

C. The one-hour average coke burn-off rate (pounds per hour) and hours of operation shall be recorded daily and maintained on-site. Coke burn-off rate shall be determined using the methods as specified in 63.1564(b)(4)(i) of 40 CFR part 63, Subpart UUU. These records shall be maintained for a minimum of five years and made available to representatives of the TCEQ or local program upon request.

D. The emissions record shall also include calculated emissions of HCN from the FCCU during the previous calendar month and the past consecutive 12-month period. HCN emissions shall be calculated using the emission factor obtained from the most recent stack test and the coke burn-off rate calculated pursuant to paragraph C of this condition.

Flare Process Requirements

23. Flares shall be designed and operated in accordance with the following requirements:

A. The flare systems shall be designed such that the combined assist natural gas and waste stream to each flare meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity under normal, upset, and maintenance flow conditions.

   The heating value and velocity requirements shall be satisfied during operations authorized by this permit. Flare testing per 40 CFR § 60.18(f) may be requested by the appropriate regional office (or is required per NSPS subpart) to demonstrate compliance with these requirements.

B. Flares shall be operated with a flame present at all times and/or have a constant pilot flame. The pilot flame shall be continuously monitored by a thermocouple or an infrared monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate and shall be calibrated at a frequency in accordance with, the manufacturer's specifications.

C. Flares shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours.

Cooling Towers

24. The Mid Plant Cooling Tower No. 2 shall be monitored for VOC in accordance with the provisions of Attachment D. Confirmed leaks shall be repaired and corrections shall be confirmed within the timelines prescribed in Attachment D. The results of the monitoring and maintenance efforts shall be recorded, and such records shall be maintained for a period of five years. The records shall be made available to the TCEQ Executive Director upon request.

    FHR shall determine compliance with the annual VOC (tons/year) MAERT limit for the Mid Plant Cooling Tower No. 2 by calculating actual annual VOC emissions using the El Paso Method, the calculation basis from MACT CC, and the length of time to repair from the time of sampling. Samples shall be taken at least monthly.

    FHR shall comply with the recordkeeping requirements established by 40 CFR 63.655(i)(4)(iii) and maintain such records for at least five years.

    FHR shall report, in the first Excess Emissions and Monitoring System Performance Report (NSPS 60.7(c), Subpart J and Db and NESHAP BB) following submittal of its annual emissions inventory, any exceedance of the annual tons/year VOC limit for the Mid Plant Cooling Tower No. 2.

25. The Mid Plant Cooling Tower No. 2 shall be operated and monitored in accordance with the following requirements:

    A. The cooling tower shall be equipped with drift eliminators having manufacturer's design assurance of 0.0005% drift or less. The permit holder shall maintain and inspect the drift eliminators when all cells of the cooling tower are shutdown while undergoing inspection or planned maintenance. The permit holder shall maintain records of all inspections and repairs.

    B. Total dissolved solids (TDS) shall not exceed 5200 parts per million by weight (ppmw) on an hourly basis and 4600 ppmw on an annual average basis. Dissolved solids in the cooling water drift are considered to be emitted as PM, PM_{10}, and $PM_{2.5}$ as represented in the permit application calculations.

    C. The Mid Plant Cooling Tower No. 2 shall be analyzed for particulate emissions using one of the following methods:

(1) Cooling water shall be sampled at least once per day for total dissolved solids (TDS); or

(2) TDS monitoring may be reduced to weekly if conductivity is monitored daily and TDS is calculated using a ratio of TDS-to-conductivity (in ppmw per µmho/cm or ppmw/siemens). The ratio of TDS-to-Conductivity shall be determined by concurrently monitoring TDS and conductivity on a weekly basis. The permit holder may use the average of two consecutive TDS-to-conductivity ratios to calculate daily TDS; or

(3) TDS monitoring may be reduced to quarterly if conductivity is monitored daily and TDS is calculated using a correlation established for the Mid Plant Cooling Tower No. 2. The correlation factor shall be the average of nine consecutive weekly TDS-to-conductivity ratios determined using Condition No. (2) above provided the highest ratio is not more than 10% larger than the smallest ratio.

(4) The permit holder shall validate the TDS-to-conductivity correlation factor once each calendar quarter. If the ratio of concurrently sampled TDS and conductivity is more than 10% higher or lower than the established factor, the permit holder shall increase TDS monitoring to weekly until a new correlation factor can be established.

D. Cooling water sampling shall be representative of the cooling tower feed water and shall be conducted using approved methods.

(1) The analysis method for TDS shall be EPA Method 160.1, ASTM D5907, and SM 2540 C [SM - 19th edition of Standard Methods for Examination of Water]. Water samples should be capped upon collection and transferred to a laboratory area for analysis. Short term and annual average emission rates of PM, PM_{10} and $PM_{2.5}$ shall be calculated using the measured TDS, the design drift rate and the daily maximum and average actual cooling water circulation rate. Alternately, the design maximum circulation rate may be used for all calculations.

(2) Alternate sampling and analysis methods may be used to comply with Paragraph D(1) of this condition with written approval from the TCEQ Regional Director.

(3) Records of all instrument calibrations and test results and process measurements used for the emission calculations shall be retained.

E. Emission rates of PM, PM_{10} and $PM_{2.5}$ shall be calculated using the measured TDS, the design drift rate and the daily maximum and average actual cooling water circulation rate for the short term and annual average rates. Alternately, the design maximum circulation rate may be used for all calculations. Emission records shall be updated monthly.

Storage Tanks

26. Storage tanks are subject to the following requirements: The control requirements specified in parts A-C of this condition shall not apply (1) where the VOC has an aggregate partial pressure of less than 0.50 psia at the maximum feed temperature or 95°F, whichever is greater, or (2) to storage tanks smaller than 25,000 gallons.

A. The tank emissions must be controlled as specified in one of the paragraphs below:

(1) An internal floating deck or “roof” shall be installed. A domed external floating roof tank is equivalent to an internal floating roof tank. The floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the floating roof: (1) a liquid-mounted seal, (2) two continuous seals mounted one above the other, or (3) a mechanical shoe seal.

(2) An open-top tank shall contain a floating roof (external floating roof tank) which uses double seal or secondary seal technology provided the primary seal consists of either a mechanical shoe seal or a liquid-mounted seal and the secondary seal is rim-mounted. A weathershield is not approvable as a secondary seal unless specifically reviewed and determined to be vapor tight.

B. For any tank equipped with a floating roof, the permit holder shall**: (03/23)**

(1) Perform the visual inspections and any seal gap measurements specified in Title 40 Code of Federal Regulations § 60.113b (40 CFR § 60.113b) Testing and Procedures (as amended at 54 FR 32973, Aug. 11, 1989) or according to the alternative specified in 40 CFR § 60.110b(e) (as amended at 86 FR 5019, Jan. 19, 2021) to verify fitting and seal integrity.

(2) Maintain records of the dates inspections were performed, any measurements made, results of inspections and measurements made (including raw data), and actions taken to correct any deficiencies noted.

C. The floating roof design shall incorporate sufficient flotation to conform to the requirements of API Code 650 dated November 1, 1998 except that an internal floating cover need not be designed to meet rainfall support requirements and the materials of construction may be steel or other materials.

D. RESERVED

E. Except for labels, logos, etc. not to exceed 15 percent of the tank total surface area, uninsulated tank exterior surfaces exposed to the sun shall be white or unpainted aluminum. Storage tanks must be equipped with permanent submerged fill pipes.

F. The permit holder shall maintain an emissions record which includes calculated emissions of VOC from all storage tanks during the previous calendar month and the past consecutive 12-month period. The emissions record shall include tank identification number, control method used, tank capacity in gallons, name of the material stored, VOC molecular weight, VOC monthly average temperature in degrees Fahrenheit, VOC vapor pressure at the monthly average material temperature in psia, and VOC throughput for the previous month and year-to-date. Records of VOC monthly average temperature are not required to be kept for unheated tanks which receive liquids that are at or below ambient temperatures.

Emissions from Tanks 40FB4020 – 40FB4024, 40FB108, and 40FB109 shall be calculated using the methods used to determine the MAERT limits in the permit renewal application, PI-1R dated August 4, 2008. Emissions from Tank 40FB3041 shall be calculated using the methods used to determine the MAERT limits in the Low Sulfur Bunker Fuel project permit amendment, PI-1 dated October 19, 2017 and authorized October 1, 2018. All other tanks shall be calculated using the methods that were used to determine the MAERT limits in the permit amendment application, PI-1 dated September 29, 2022. Sample calculations shall be attached to a copy of this permit at the plant site. **(03/23)**

G. In addition to the emissions record identified in Special Condition 26.F, the following requirement is applicable for all floating roof storage tanks: **(03/23)**

(1) Emissions of VOC from all floating roof storage tanks shall be calculated based on the actual tank liquid height and change in liquid level, then calculated to reflect actual throughput, as the throughput is based on the change in the liquid height.

(2) The emissions record shall include the actual tank liquid height, change in liquid level, and the calculated actual throughput based on the change in liquid height.

27. Storage tanks 08FB145R1 and 08FB146 shall be routed to a vapor combustor at all times (EPN: V-FB145/6). The vapor combustor shall be designed and operated in accordance with the following requirements:

    A. The vapor combustor unit (VCU) shall achieve 99% control of the waste gas directed to it. This shall be ensured by maintaining the temperature in, or immediately downstream of, the combustion chamber above 1,500 °F prior to the initial stack test performed in accordance with Special Condition 30. Following the completion of that stack test, the six-minute average temperature shall be maintained above the minimum one-hour average temperature maintained during the last satisfactory stack test.

    B. The temperature measurement device shall reduce the temperature readings to an averaging period of 6 minutes or less and record it at that frequency. The temperature monitor shall be installed, calibrated or have a calibration check performed at least annually, and maintained according to the manufacturer's specifications. The device shall have an accuracy of the greater of ±2 percent of the temperature being measured expressed in degrees Celsius or ±2.5ºC.

    C. Quality assured (or valid) data must be generated when the VCU is operating. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the VCU operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

28. The vapor combustor shall be operated with no visible emissions and have a constant pilot flame during all times waste gas could be directed to it. The pilot flame shall be continuously monitored by a thermocouple or an infrared/ultra-violet monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to and shall be calibrated or have a calibration check performed at a frequency in accordance with, the manufacturer’s specifications.

Initial Determination of Compliance

29. Sampling ports and platform(s) shall be incorporated into the design of the combustion source stacks according to the specifications set forth in the attachment entitled “Chapter 2, Stack Sampling Facilities” of the TCEQ Sampling Procedures Manual. Alternate sampling facility designs must be submitted for approval to the TCEQ Regional Director.

30. The permit holder shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the sources listed in Special Condition No. 31. The permit holder is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and the U.S. EPA Reference Methods.

    Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office of Air, Air Permits Division. Test waivers and alternate/equivalent procedure proposals for 40 CFR Part 60 testing which must have EPA approval shall be submitted to the TCEQ Regional Director.

    A. The appropriate TCEQ Regional Office shall be notified not less than 30 days prior to sampling. The notice shall include:

(1) Proposed date for pretest meeting.

(2) Date sampling will occur.

(3) Name of firm conducting sampling.

(4) Type of sampling equipment to be used.

(5) Method or procedure to be used in sampling.

(6) Description of any proposed deviation from the sampling procedures specified in this permit or TCEQ/EPA sampling procedures.

(7) Procedure/parameters to be used to determine worst case emissions during the sampling period.

The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for the test reports. The TCEQ Regional Director must approve any deviation from specified sampling procedures.

B. Sources listed in Special Condition 31 shall be tested for the specific air contaminants listed in that condition.

C. The heaters shall be sampled within 60 days of achieving the maximum firing rate, but no later than 180 days after the heaters were modified. Heaters and the VCU shall also be sampled at such other times as may be required by the TCEQ Executive Director. Requests for additional time to perform sampling shall be submitted to the appropriate regional office.

D. The VCU being sampled shall operate at the maximum hourly loading rate in gallons per hour or barrels per hour of any authorized VOC with a true vapor pressure equal to or greater than 0.50 psia into either a barge or a ship from loading dock 8, 9 or 10 during stack emission testing. The heaters shall be sampled at the maximum firing rates.

These conditions/parameters and any other primary operating parameters that affect the emission rate shall be monitored and recorded during the stack test. Any additional parameters shall be determined at the pretest meeting and shall be stated in the sampling report. If the plant is unable to operate at maximum loading/firing/exhaust gas generation rates during testing, then future loading/firing/exhaust gas generation rates shall be limited to the rates established during testing. Permit conditions and parameter limits may be waived during stack testing performed under this condition if the proposed condition/parameter range is identified in the test notice specified in paragraph A and accepted by the TCEQ Regional Office. Permit allowable emissions and emission control requirements are not waived and still apply during stack testing periods. **(1/24)**

During subsequent operations,

(1) if the maximum hourly loading rate in gallons per hour or barrels per hour of VOC with a true vapor pressure equal to or greater than 0.50 psia into either a barge or a ship from loading dock 8, 9 or 10 is greater than that recorded during the test period, or

(2) if the monthly average heater firing rates exceeds those maintained during the stack sampling, stack sampling of that facility shall be performed at the new operating conditions within 120 days. This sampling may be waived by the TCEQ Air Section Manager for the region.

E. One copy of the final sampling report shall be forwarded to the appropriate TCEQ regional office within 60 days after sampling is completed. Sampling reports shall comply with the attached provisions entitled “Chapter 14, Contents of Sampling Reports” of the TCEQ Sampling Procedures Manual.

F. Per AMOC 159, testing of Tank Nos. 08FB145R1 and 08FB146 shall be waived until the material stored in either tank has a TVP greater than 0.5 psia.

31. Special Condition Nos. 29 and 30 shall apply to the following sources:

EPN	FIN*	Source Name	Pollutants
VCS-1	LW-8	Marine Vapor Combustor	CO, NO_x, VOC
LEUHOH	42BA5	LEU Hot Oil Heater	CO, NO_x, ammonia
JJ-4	39BA3900	NHT Charge Heater	CO, NO_x, ammonia
JJ-4	39BA3901	CCR Hot Oil Heater	CO, NO_x, ammonia
A-203	42BA1	Crude Heater	NO_x, SO_2, CO
A-204	42BA3	Vacuum Heater	NO_x, SO_2, CO
AA-4	01BF102	FCCU CO Boiler Off-Gas Scrubber	NO_x, SO_2, PM, CO, HCN
DDS-HTRSTK	56BA1	DDS Charge Heater	NO_x, CO
DDS-HTRSTK	56BA2	DDS Fractionator Reboiler	NO_x, CO
KK-3	37BA1	DHT Charge Heater	NO_x
KK-3	37BA2	DHT Stripper Reboiler	NO_x
LSGHTR	47BA1	LSG Hot Oil Heater	NO_x, CO
MX-1	54BA1	MX Unit Hot Oil Heater	NO_x, CO
R-201	43BF1	Crude Boiler	NO_x, SO_2, CO
V-FB145/6	08FB145/6	Vapor Combustor	NO_x, CO, VOC
JJ-7	CCRAUXHTR	CCR Auxiliary Charge Heater	NO_x, CO, ammonia

Fugitives

Piping, Valves, Connectors, Pumps, Agitators, and Compressors - 28VHP

32. The following requirements apply to piping, valves, connectors, pumps, agitators, and compressors containing or in contact with fluids that could reasonably be expected to contain greater than or equal to 10 weight percent volatile organic compounds (VOC) at any time. **(03/23)**

A. The requirements of paragraphs F and G shall not apply (1) where the Volatile Organic Compound (VOC) has an aggregate partial pressure or vapor pressure of less than 0.044 pounds per square inch, absolute (psia) at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

The exempted components may be identified by one or more of the following methods:

- piping and instrumentation diagram (PID);
- a written or electronic database or electronic file;
- color coding;

- a form of weatherproof identification; or
- designation of exempted process unit boundaries.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked buried connectors shall be welded.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made readily available upon request. The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in subparagraph A above. If an unsafe to monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe to monitor times. A difficult to monitor component for which quarterly monitoring is specified may instead be monitored annually.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. Any leaks discovered through AVO inspection shall be tagged and/or replaced or repaired.

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open-ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

(1) a cap, blind flange, plug, or second valve must be installed on the line or valve; or

(2) the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once within the 72-hour period following the creation of the open-ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings of 500 ppmv and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.

F. Accessible valves shall be monitored by leak checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. If a relief valve is equipped with rupture disc, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity.

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed at least quarterly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR part 60, appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. A calculated average is not required when all of the compounds in the mixture have a response factor less than 10 using methane. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

I. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I) or 500 pounds, whichever is greater, the TCEQ Regional Manager and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. The instrument monitoring record shall include the time that monitoring took place for no less than 95% of the instrument readings recorded. Records of physical inspections shall be noted in the operator's log or equivalent. **(03/23)**

K. Alternative monitoring frequency schedules of 30 TAC § 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS) and does not constitute approval of alternative standards for these regulations.

M. As an alternative to comparing the daily emission rate of the components on the delay of repair (DOR) list to the total emissions from a unit shutdown per the requirements of Special Condition No. 32, Subparagraph I, the cumulative hourly emission rate of all components on the DOR list may be compared to ten percent of the fugitive short term allowable on the Maximum Allowable Emission Rate Table in order to determine if the TCEQ Regional Director and any local program is to be notified. In addition, the hourly emission rates of each specific compound on the DOR list must be less than ten percent of speciated hourly fugitive emission rate of the same compound.

N. Relief valves and rupture discs are exempt from weekly visual monitoring if they are monitored quarterly via an approved gas analyzer, or if the relief valves are relieved to a control device.

33. In addition to the weekly physical inspection required by Item E of Special Condition 32, all connectors in fugitive areas F-01, F-65 F-26, F-37, F-39, F-40, F-42, and F-GB in gas\vapor and light liquid service shall be monitored annually with an approved gas analyzer in accordance with Items F thru J of Special Condition 32. Alternative monitoring frequency schedules ("skip options") of Title 40 Code of Federal Regulations Part 63, Subpart H, National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks, may be used in lieu of the monitoring frequency required by this permit condition. Compliance with this condition does not assure compliance with requirements of applicable state or federal regulation and does not constitute approval of alternative standards for these regulations. **(03/23)**

Instead of the leak definition of 2,000 ppmv specified in Special Condition No. 32.H for pump and compressor seals in the Saturates Gas Plant No. 2, NHT/CCR Platformer Unit, Crude Unit No. 4, FCCU, and Delayed Coker, the permit holder shall use a leak definition of 500 ppmv for pumps and compressor seals in these areas.

Piping, Valves, Pumps, and Compressors in contact with Ammonia – 28AVO

34. Except as may be provided for in the Special Conditions of this permit, the following requirements apply to the above-referenced equipment in SCR and SNCR (FCCU) Ammonia Service:

A. SCR Ammonia Service:

(1) Audio, olfactory, and visual checks for ammonia leaks within the SCR operating area shall be made twice per shift.

(2) Immediately, but no later than one hour upon detection of a leak, plant personnel shall take the following actions:

(a) Isolate the leak.

(b) Commence repair or replacement of the leaking component.

(c) Use a leak collection/containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the TCEQ upon request.

B. SNCR (FCCU) Ammonia Service:

(1) Audio, olfactory, and visual checks for ammonia leaks within the SCR operating area shall be made once per shift.

(2) Immediately, but no later than one-hour upon detection of a leak, plant personnel shall make one or more of the following attempts:

(a) Isolate the leak.

(b) Commence repair or replacement of the leaking component.

(c) Use a leak collection or containment system to prevent the leak until repair or replacement can be made.

Records shall be maintained at the plant site of all repairs and replacements made. These records shall be made available to representatives of the TCEQ upon request.

35. The following requirements apply to Piping, Valves, Pumps, and Compressors in Petroleum Land Loading Service - EPN F-101:

A. Audio, olfactory, and visual checks for petroleum product leaks within the petroleum tank truck operating area shall be made monthly.

B. Every reasonable effort shall be made to repair or replace a leaking component within 15 days after a leak is found. If the repair or replacement of a leaking component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired or replaced until a scheduled shutdown shall be identified in a list to be made available to representatives of the TCEQ upon request.

Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the TCEQ upon request.

Piping, Valves, Connectors, Pumps, Agitators, and Compressors – LDSN-DRF (12/23)

36. In lieu of complying with the monitoring conditions of Special Conditions No. 32 and 33, the permit holder may utilize the Leak Detection Sensor Network-Detection Response Framework (LDSN-DRF) as approved by Alternate Means of Control (AMOC) No. 160 for all or a portion of the piping, valves, connectors, pumps, agitators, and compressors in VOC service in the Mid Crude Unit (EPN F-42) that are otherwise subject to Special Conditions No. 32 and 33. If the permit holder chooses

to comply with AMOC No. 160 in lieu of the provisions of Special Conditions Nos. 32 and 33, the permit holder shall comply with the following requirements of this special condition in addition to the monitoring, recordkeeping, and reporting requirements within AMOC No. 160.

A. The requirements of paragraph F shall not apply (1) where the Volatile Organic Compound (VOC) has an aggregate partial pressure or vapor pressure of less than 0.044 pounds per square inch, absolute (psia) at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

   The exempted components may be identified by one or more of the following methods:

   - piping and instrumentation diagram (PID);
   - a written or electronic database or electronic file;
   - color coding;
   - a form of weatherproof identification; or
   - designation of exempted process unit boundaries.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked buried connectors shall be welded.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through. Any leaks discovered through AVO inspection shall be tagged and/or replaced or repaired.

   Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open-ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

   (1) a cap, blind flange, plug, or second valve must be installed on the line or valve; or

   (2) the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once within the 72-hour period following the creation of the open-ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings of 500 ppmv and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.

F. If a relief valve is equipped with rupture disc, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. RESERVED

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

I. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I) or 500 pounds, whichever is greater, the TCEQ Regional Manager and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. The instrument monitoring record shall include the time that monitoring took place for no less than 95% of the instrument readings recorded. Records of physical inspections shall be noted in the operator’s log or equivalent.

K. RESERVED

L. RESERVED

M. As an alternative to comparing the daily emission rate of the components on the delay of repair (DOR) list to the total emissions from a unit shutdown per the requirements of Special Condition No. 36, Subparagraph I, the cumulative hourly emission rate of all components on the DOR list may be compared to ten percent of the fugitive short term allowable on the Maximum Allowable Emission Rate Table in order to determine if the TCEQ Regional Director and any local program is to be notified. In addition, the hourly emission rates of each specific compound on the DOR list must be less than ten percent of speciated hourly fugitive emission rate of the same compound.

N. Instead of the leak definition of 2,000 ppmv specified in Special Condition No. 36.H for pump and compressor seals, the permit holder shall use a leak definition of 500 ppmv for pumps and compressor seals in the Mid Crude Unit.

Federal New Source Review Applicability

37. The amendment for the Domestic Crude Project (DCP) issued May 23, 2014 and amendment issued June 28, 2019, was determined not to be subject to major new source review by identifying projected actual emission rates for one or more facilities affected and unaffected by the project. Actual emissions from these facilities shall be monitored, recorded and reports made in accordance with 30 TAC § 116.127, including the following affected facilities currently authorized in Permit No. 8803A: West Crude Charge Heater (40BA101); West Crude Vacuum Heater (40BA401); and Tanks 08FB118, 08FB145R1, 08FB146, 15FB501, 15FB502R1, 15FB503R1, 15FB506R1, , 40FB3041, 40FB3042, and 40FB3045. For Tank 40FB3041, once it is modified as part of the LSBF Project, authorized via amendment to Permit No. 6819A issued on October 1, 2018, and thus any emissions increases are no longer solely the result of the DCP Project, FHR will use the projected actual emissions represented in this DCP application for each tank rather than actual emissions from each for purposes of determining whether annual emissions from the DCP trigger the reporting requirements of 30 TAC 116.127(d).

The amendment application for the DCP, used the incremental increase in emissions methodology to determine the difference between projected actual emissions and baseline actual emissions for uncontrolled marine loading (EPN W-8) and various boilers while excluding emissions following the project that the uncontrolled marine loading (EPN W-8) and various boilers could have accommodated and that are unrelated to the Domestic Crude Project. For the uncontrolled marine loading (EPN W-8) and various boilers, the permit holder shall calculate and maintain a record of the incremental annual emissions increase resulting from the Domestic Crude Project, in tons per year, on a calendar basis, for a period of five years following resumption of regular operations following the Domestic Crude Project.

The permit holder shall submit a report to the Executive Director if the actual emissions from the Domestic Crude Project exceed the baseline actual emissions by a significant amount for that pollutant, and the incremental increase in emissions from the uncontrolled marine loading (EPN W-8) and various boilers exceeds the incremental increase represented in the permit amendment application. The report shall be submitted to the Executive Director within 60 days of the calendar year and shall contain:

(A) The name, address and telephone number of the major stationary source; and

(B) The calculated incremental emissions increases.

The permit holder shall make the information required to be documented and maintained by this special condition available for review upon the request of the Executive Director or local air pollution control program.

38. The DCP permit amendment, issued May 23, 2014, was conditional on the completion of emission reduction projects, which as of the issuance of the amendment dated June 28, 2019, have been completed except for the:

Installation of a Floating Roof in Tank 40FB3044, which was removed from service prior to commencement of operation of the DCP. Tank 40FB3044 shall not be returned to service until after a floating roof has been installed.

The permit holder shall maintain records of these emission reductions.

Maintenance, Startup, and Shutdown

39. Startup and shutdown emissions due to the activities identified in Special Condition 40 are authorized from facilities and emission points in Flexible Permit 8803A and the facilities authorized by this permit.

40. This permit authorizes the emissions from the facilities identified in Special Condition 39 for the planned maintenance, startup, and shutdown (MSS) activities summarized in the MSS Activity Summary (Attachment C) attached to this permit.

    This permit authorizes emissions from the following temporary facilities used to support planned MSS activities at permanent site facilities: frac tanks, containers, vacuum trucks, facilities used for abrasive blasting, portable control devices identified in Special Condition 51, and controlled recovery systems. Emissions from temporary facilities are authorized provided the temporary facility (a) does not remain on the plant site for more than 12 consecutive months, (b) is used solely to support planned MSS activities at the permanent site facilities authorized by this permit, and (c) does not operate as a replacement for an existing authorized facility.

    Attachment A identifies the inherently low emitting MSS activities that may be performed at the refinery. Emissions from activities identified in Attachment A shall be considered to be equal to the potential to emit represented in the permit application. The estimated emissions from the activities listed in Attachment A must be revalidated annually. This revalidation shall consist of the estimated emissions for each type of activity and the basis for that emission estimate.

    Routine maintenance activities, as identified in Attachment B may be tracked through the work orders or equivalent. Emissions from activities identified in Attachment B shall be calculated using the number of work orders or equivalent that month and the emissions associated with that activity identified in the permit application.

    The performance of each planned MSS activity not identified in Attachments A or B and the emissions associated with it shall be recorded and include at least the following information:

    A. the physical location at which emissions from the MSS activity occurred, including the emission point number and common name for the point at which the emissions were released into the atmosphere;

    B. the type of planned MSS activity and the reason for the planned activity;

    C. the common name and the facility identification number, if applicable, of the facilities at which the MSS activity and emissions occurred;

    D. the date of the MSS activity and its duration; and

    E. the estimated quantity of each air contaminant, or mixture of air contaminants, emitted with the data and methods used to determine it. The emissions shall be estimated using the methods identified in the permit application, consistent with good engineering practice.

       All MSS emissions shall be summed monthly and the rolling 12-month emissions shall be updated on a monthly basis.

41. Process units and facilities, with the exception of those identified in Special Conditions 44, 45, 47, and Attachment A shall be depressurized, emptied, degassed, and placed in service in accordance with the following requirements.

A. The process equipment shall be depressurized to a control device or a controlled recovery system prior to venting to atmosphere, degassing, or draining liquid. Equipment that only contains material that is liquid with VOC partial pressure less than 0.50 psi at the normal process temperature and 95°F may be opened to atmosphere and drained in accordance with paragraph C of this special condition. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded.

B. If mixed phase materials must be removed from process equipment, the cleared material shall be routed to a knockout drum or equivalent to allow for managed initial phase separation. If the VOC partial pressure is greater than 0.50 psi at either the normal process temperature or 95°F, any vents in the system must be routed to a control device or a controlled recovery system. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. Control must remain in place until degassing has been completed or the system is no longer vented to atmosphere.

C. All liquids from process equipment or storage vessels must be removed to the maximum extent practical prior to opening equipment to commence degassing and/or maintenance. Liquids must be drained into a closed vessel unless prevented by the physical configuration of the equipment. If it is necessary to drain liquid into an open pan or sump, the liquid must be covered or transferred to a covered vessel within one hour of being drained. After draining is complete, empty open pans may remain in use for housekeeping reasons to collect incidental drips.

D. If the VOC partial pressure is greater than 0.50 psi at the normal process temperature or 95°F, facilities shall be degassed using good engineering practice to ensure air contaminants are removed from the system through the control device or controlled recovery system to the extent allowed by process equipment or storage vessel design. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded. The control device or recovery system utilized shall be recorded with the estimated emissions from controlled and uncontrolled degassing calculated using the methods that were used to determine allowable emissions for the permit application.

The following requirements do not apply to fugitive components, pumps, and compressors.

(1) For MSS activities identified in Attachment B, the following option may be used in lieu of (2) below. The facilities being prepared for maintenance shall not be vented directly to atmosphere, except as necessary to verify an acceptable VOC concentration and establish isolation of the work area, until the VOC concentration has been verified to be less than 10 percent of the lower explosive limit (LEL) per the site safety procedures.

(2) The locations and/or identifiers where the purge gas or steam enters the process equipment or storage vessel and the exit points for the exhaust gases shall be recorded. PFD's or P&ID's may be used to demonstrate compliance with the requirement. Documented refinery procedures used to de-inventory equipment to a control device for safety purposes (i.e., hot work or vessel entry procedures) that achieve at least the same level of purging may be used in lieu of the above. If the process equipment is purged with a gas, two system volumes of purge gas must have passed through the control device or controlled recovery system before the vent stream may be sampled to verify acceptable VOC concentration prior to uncontrolled venting. The VOC sampling and analysis shall be performed using an instrument meeting the requirements of Special Condition 42. The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process

equipment or vessel being purged. The facilities shall be degassed to a control device or controlled recovery system until the VOC concentration is less than 10,000 ppmv or less than 10% of the lower explosive limit (LEL).

E. Gases and vapors with VOC partial pressure greater than 0.50 psi may be vented directly to atmosphere if all the following criteria are met:

(1) It is not technically practicable to depressurize or degas, as applicable, into the process.

(2) There is not an available connection to a plant control system (flare).

(3) There is no more than 50 lbs of air contaminant to be vented to atmosphere during shutdown or startup, as applicable.

All instances of venting directly to atmosphere per Special Condition 41.E must be documented when occurring as part of any MSS activity. The emissions associated with venting without control must be included in the work order, shift log, or equivalent for those planned MSS activities identified in Attachment B.

42. Air contaminant concentration shall be measured using an instrument/detector meeting one set of requirements specified below.

A. VOC concentration shall be measured using an instrument meeting all the requirements specified in EPA Method 21 (40 CFR Part 60, Appendix A) with the following exceptions:

(1) The instrument shall be calibrated within 24 hours of use with a calibration gas such that the response factor of the VOC (or mixture of VOCs) to be monitored shall be less than 2.0. The calibration gas and the gas to be measured, and its approximate response factor shall be recorded.

(2) Sampling shall be performed as directed by this permit in lieu of section 8.3 of Method 21. During sampling, data recording shall not begin until after two times the instrument response time. The date and time shall be recorded, and VOC concentration shall be monitored for at least 5 minutes and the highest concentration recorded. The highest measured VOC concentration shall not exceed the specified VOC concentration limit prior to uncontrolled venting.

(3) If a TVA-1000 series FID analyzer, calibrated with methane is used to determine the VOC concentration, a measured concentration of 34,000 ppmv may be considered equivalent to 10,000 ppmv as VOC.

B. Colorimetric gas detector tubes may be used to determine air contaminant concentrations if they are used in accordance with the following requirements.

(1) The air contaminant concentration measured is less than 80 percent of the range of the tube. If the maximum range of the tube is greater than the release concentration defined in (3) below, the concentration measured is at least 20 percent of the maximum range of the tube.

(2) The tube is used in accordance with the manufacturer’s guidelines.

(3) At least 2 samples taken at least 5 minutes apart must satisfy the following prior to uncontrolled venting:

measured contaminant concentration (ppmv) < release concentration.

Where the release concentration is:

10,000*mole fraction of the total air contaminants present that can be detected by the tube.

The mole fraction may be estimated based on process knowledge. The release concentration and basis for its determination shall be recorded.

Records shall be maintained of the tube type, range, measured concentrations, and time the samples were taken.

C. Lower explosive limit measured with an MSA Sirius lower explosive limit detector.

(1) The detector shall be calibrated monthly with a certified pentane calibration gas equivalent to 58 percent of the lower explosive limit (LEL) for pentane. Records of the calibration date/time and calibration result (pass/fail) shall be maintained.

(2) A daily functionality test shall be performed on each detector using the same certified gas standard used for calibration. The LEL monitor shall read no lower than 90 percent of the calibration gas certified value. Records, including the date/time and test results, shall be maintained.

(3) A certified methane gas standard equivalent to 29 percent of the LEL for methane may be used for calibration and functionality tests provided that the LEL response is within 95 percent of that for pentane.

(4) For any test environments in which pentane is not present in the sources tested, a determination shall be documented and maintained on site that the monitor as calibrated with the pentane simulant gas will provide conservatively accurate results and is a sensitive monitor for the components in question to set the decision to allow uncontrolled release of VOC to the atmosphere. Otherwise, an alternative monitoring approach must be used.

(5) The facility may submit a request for a determination that additional LEL detectors, which provide conservatively accurate results and are sensitive for the components in question, may be used. The permit holder shall obtain approval from the TCEQ prior to using a different LEL detector.

D. Lower explosive limit measured with all other lower explosive limit detectors.

(1) The detector shall be calibrated within 30 days of use with a certified pentane calibration gas equivalent to 25 percent of the lower explosive limit (LEL) for pentane. Records of the calibration date/time and calibration result (pass/fail) shall be maintained.

(2) A functionality test shall be performed on each detector within 24 hours of use using the same certified gas standard used for calibration. The LEL monitor shall read no lower than 90 percent of the calibration gas certified value. Records, including the date/time and test results, shall be maintained.

(3) A certified methane gas standard equivalent to 25 percent of the LEL for methane may be used for calibration and functionality tests provided that the LEL response is within 95 percent of that for pentane.

43. If the removal of a component for repair or replacement results in an open-ended line or valve, the open-ended line is exempt from any NSR permit condition requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period:

A. A cap, blind flange, plug, or second valve must be installed on the line or valve, or demonstrate that the line, valve, component, etc., has been double blocked from the process; or

B. The permit holder shall verify that there is no leakage from the open-ended line or valve. The open-ended line or valve shall be monitored on a weekly basis in accordance with the applicable NSR permit condition for fugitive emission monitoring except that a leak is defined as any VOC reading greater than background. Leaks must be repaired no later than one calendar day after the leak is detected or a cap, blind flange, plug, or second valve must be installed on the line or valve. The results of this weekly check and any corrective actions taken shall be recorded.

44. This permit authorizes emissions for the storage tanks identified in the attached facility list during planned floating roof landings. Unless the tank vapor space is routed to a control device meeting the requirements of Special Condition 51, tank roofs may only be landed for changes of tank service or tank inspection or maintenance as identified in the permit application. Emissions from change of service tank landings shall not exceed 10 tons of VOC in any rolling 12-month period. Tank roof landings include all operations when the tank floating roof is on its supporting legs. These emissions are subject to the maximum allowable emission rates indicated on the MAERT. The following requirements apply to tank roof landings.

A. The tank liquid level shall be continuously lowered after the tank floating roof initially lands on its supporting legs until the tank has been drained to the maximum extent practicable without entering the tank. Liquid level may be maintained steady for a period of up to three hours, if necessary, to allow for valve lineups and pump changes necessary to drain the tank. This requirement does not apply where the vapor under a floating roof is routed to control or a controlled recovery system during this process.

This requirement does not apply if the level is lowered to allow for maintenance that is expected to be completed in less than 24 hours. In that case, the tank must be filled, and the roof floated within 24 hours of landing the roof and the evolution documented in accordance with Special Condition 41.E.

B. If the VOC partial pressure of the liquid previously stored in the tank is greater than 0.50 psi at 95°F, tank refilling or degassing of the vapor space under the landed floating roof must begin within 24 hours after the tank has been drained unless the vapor under the floating roof is routed to control or a controlled recovery system during this period. Floating roof tanks with liquid capacities less than 100,000 gallons may be degassed without control if the VOC partial pressure of the standing liquid in the tank has been reduced to less than 0.02 psia prior to ventilating the tank. Controlled degassing of the vapor space under landed roofs shall be completed as follows:

(1) Any gas or vapor removed from the vapor space under the floating roof must be routed to a control device or a controlled recovery system and controlled degassing must be maintained until the VOC concentration is less than 10,000 ppmv or less than 10 percent of the LEL. The locations and identifiers of vents other than permanent roof fittings and seals, control device or controlled recovery system, and controlled exhaust stream shall be recorded. There shall be no other gas/vapor flow out of the vapor space under the floating roof when degassing to the control device or controlled recovery system.

(2) The vapor space under the floating roof shall be vented using good engineering practice to ensure air contaminants are flushed out of the tank through the control device or controlled recovery system to the extent allowed by the storage tank design until the VOC concentration is less than 10,000 ppmv or 10% of the LEL.

(3) A volume of gas equivalent to twice the volume of the vapor space under the floating roof must have passed through the control device or into a controlled recovery system before the vent stream may be sampled to verify acceptable VOC concentration. The measurement of the gas volume shall not include any make-up air introduced into the control device or recovery system. Documented refinery procedures used to de-inventory equipment to a control device for safety purposes (i.e., hot work or vessel entry procedures) that achieve at least the same level of purging may be used in lieu of the above. The VOC sampling and analysis shall be performed as specified in Special Condition 42.

(4) The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process equipment or vessel being purged.

(5) If ventilation is to be maintained with emission control, the control device shall be monitored in accordance with Special Condition 51.

Degassing must be performed every 24 hours unless there is no standing liquid in the tank or the VOC partial pressure of the remaining liquid in the tank is less than 0.15 psia.

C. The tank shall not be opened except as necessary to set up for degassing and cleaning, or ventilated without control, until either all standing liquid has been removed from the tank or the liquid in the tank has a VOC partial pressure less than 0.02 psia. These criteria may be demonstrated in any one of the following ways.

(1) Low VOC partial pressure liquid that is soluble with the liquid previously stored may be added to the tank to lower the VOC partial pressure of the liquid mixture remaining in the tank to less than 0.02 psia. This liquid shall be added during tank degassing if practicable. The estimated volume of liquid remaining in the drained tank and the volume and type of liquid added shall be recorded. The liquid VOC partial pressure may be estimated based on this information and engineering calculations.

(2) If water or other liquid is added or sprayed into the tank to remove standing VOC, acceptable vapor pressure may be demonstrated using any of the three methods below:

(a) Take a representative sample of the liquid remaining in the tank and verify no visible sheen using the static sheen test per 40 CFR 435 Subpart A, Appendix 1.

(b) Take a representative sample of the liquid remaining in the tank and verify hexane soluble VOC concentration is less than 1000 ppmw using EPA Method 1664 (may also use 8260B or 5030 with 8015 from SW-846).

(c) Stop ventilation and close the tank for at least 24 hours. When the tank manway is opened after this period, verify VOC concentration is less than 1000 ppmv through the procedure in Special Condition 42.

(3) No standing liquid verified through visual inspection.

Once the VOC partial pressure is verified less than 0.02 psia, any subsequent / additional water flushes that may be performed do not trigger additional verification. The permit holder shall maintain records to document the method used to release the tank.

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E. The occurrence of each roof landing and the associated emissions shall be recorded, and the rolling 12-month tank roof landing emissions shall be updated on a monthly basis.

These records shall include at least the following information:

(1) the identification of the tank and emission point number, and any control devices or recovery systems used to reduce emissions;

(2) the reason for the tank roof landing;

(3) for the purpose of estimating emissions, the date, time and other information specified for each of the following events:

(a) the roof was initially landed,

(b) all liquid was pumped from the tank to the extent practical,

(c) start and completion of controlled degassing, and total volumetric flow,

(d) all standing liquid was removed from the tank or any transfers of low VOC partial pressure liquid to or from the tank including volumes and vapor pressures to reduce tank liquid VOC partial pressure to <0.02 psi,

(e) if there is liquid in the tank, VOC partial pressure of liquid, start and completion of uncontrolled degassing, and total volumetric flow,

(f) refilling commenced, liquid filling the tank, and volume necessary to float the roof, and

(g) tank roof off supporting legs, floating on liquid.

(4) the estimated quantity of each air contaminant, or mixture of air contaminants, emitted between Events (c) and (g) with the data and methods used to determine it. The emissions associated with roof landing activities shall be calculated using the methods described in Section 7.1.3.2 of AP-42 "Compilation of Air Pollution Emission Factors, Chapter 7 - Storage of Organic Liquids" dated November 2006 and the permit application.

45. Fixed roof tanks shall not be ventilated without control, until either all standing liquid has been removed from the tank or the liquid in the tank has a VOC partial pressure less than 0.02 psia. This shall be verified and documented through one of the criteria identified in Special Condition 44.C. Fixed roof tanks manways may be opened without emission controls when there is standing liquid with a VOC partial pressure greater than 0.02 psi vapor as necessary to set up for degassing and cleaning. One manway may be opened when necessary to allow access to the tank to remove or de-volatilize the remaining liquid. The emission control system shall meet the requirements of Special Condition 44.B.(1) through 44.B.(5) and records maintained per Special Condition 44.E.(3)c through 44.E.(3)e, and 44.E.(4). Low vapor pressure liquid may be added to and removed from the tank as necessary to lower the vapor pressure of the liquid mixture remaining in the tank to less than 0.02 psia.

46. The following requirements apply to vacuum and air mover truck operations to support planned MSS at this site:

A. Vacuum pumps and blowers shall not be operated on trucks containing or vacuuming liquids with VOC partial pressure greater than 0.50 psi at 95°F unless the vacuum/blower exhaust is routed to a control device or a controlled recovery system.

B. When the vacuum pump is operating, equip fill line intake with a “duckbill” or equivalent attachment if the hose end cannot be submerged in the liquid being collected.

C. A daily record containing the information identified below is required for each vacuum truck in operation at the site each day.

(1) Prior to initial use, identify any liquid in the truck. Record the liquid level and document that the VOC partial pressure is less than 0.50 psi if the vacuum exhaust is not routed to a control device or a controlled recovery system. After each liquid transfer, identify the liquid transferred and document that the VOC partial pressure is less than 0.50 psi if the vacuum exhaust is not routed to a control device or a controlled recovery system.

(2) For each liquid transfer made with the vacuum operating, record the duration of any periods when air may have been entrained with the liquid transfer. The reason for operating in this manner and whether a "duckbill" or equivalent was used shall be recorded. Short, incidental periods, such as those necessary to walk from the truck to the fill line intake, do not need to be documented.

(3) If the vacuum truck exhaust is controlled by a device other than an engine or oxidizer, VOC exhaust concentration shall be measured using an instrument meeting the requirements of Special Condition 42 upon commencing each transfer, at the end of each transfer, and as required by Special Condition 51 during each transfer.

(4) The volume in the vacuum truck at the end of the day, or the volume unloaded, as applicable.

D. The permit holder shall determine the vacuum truck emissions each month using the daily vacuum truck records and the calculation methods utilized in the permit application. If records of the volume of liquid transferred for each uncontrolled vacuum truck pick-up are not maintained, the emissions shall be determined using the physical properties of the liquid vacuumed with the greatest potential emissions. Rolling 12-month vacuum truck emissions shall also be determined on a monthly basis.

E. If the VOC partial pressure of all the liquids vacuumed into the truck is less than 0.10 psi, this shall be recorded when the truck is unloaded or leaves the plant site, and the emissions may be estimated as the maximum potential to emit for a truck in that service as documented in the permit application. The recordkeeping requirements in Special Condition 46.A through 46.D do not apply.

47. The following requirements apply to frac, or temporary, tanks and vessels used in support of MSS activities.

A. Except for labels, logos, etc. not to exceed 15 percent of the tank/vessel total surface area, the exterior surfaces of these tanks/vessels that are exposed to the sun shall be white or aluminum. This requirement does not apply to tanks/vessels that only vent to atmosphere when being filled.

B. These tanks/vessels must be covered and equipped with fill pipes that discharge within 6 inches of the tank/vessel bottom. If the VOC partial pressure of the liquid in the tank is greater than 0.5 psi at 95°F, the tanks vents must be routed to a control device or controlled recovery system when the tank is being filled.

C. These requirements do not apply to vessels storing less than 100 gallons of liquid that are closed such that the vessel does not vent to atmosphere.

D. The permit holder shall maintain an emissions record which includes calculated emissions of VOC from all frac tanks during the previous calendar month and the past consecutive 12-month period. The record shall include tank identification number, dates put into and removed from service, control method used, tank capacity and volume of liquid stored in gallons, name of the material stored, VOC molecular weight, and VOC partial pressure at the estimated monthly average material temperature in psia. Filling emissions for tanks shall be calculated using the TCEQ publication titled "Technical Guidance Package for Chemical Sources - Loading Operations" and standing emissions determined using: the TCEQ publication titled "Technical Guidance Package for Chemical Sources - Storage Tanks."

E. If the tank/vessel is used to store liquid with VOC partial pressure less than 0.10 psi at 95°F, records may be limited to the days the tank is in service and the liquid stored. Emissions may be estimated based upon the potential to emit as identified in the permit application.

48. The following requirements apply to tank MSS activities to ensure acceptable off-site impacts.

A. Tank MSS emissions activities include tank degassing, tank opening, tank refilling following a degassing/cleaning until the roof is floated, and tank refilling not following a degassing/cleaning until the roof is floated. Only one of each type of activity may occur at any time for any liquid type (crude oil, benzene, lights, and distillates) at the site. Different tank MSS emissions activities may occur concurrently.

B. All emissions from tanks with landed roofs being filled with product grade benzene shall be routed to a control device meeting the requirements of Special Condition 51 unless the tank has been cleaned, degassed, and is at least 1650 feet from the property line. All emissions from tanks with landed roofs being filled with reformate shall be routed to a control device meeting the requirements of Special Condition 51 unless the tank has been cleaned, degassed, and is at least 1,300 feet from the property line. For benzene and reformate tanks, a refill following a tank degassing and a refill not following a tank degassing will not occur at the same time unless the emissions from both are controlled.

C. The MSS emissions from the SRU Incinerators and emissions from controlled tank refills not following a tank degassing/cleaning at Tanks FB511, FB512, FB513, or FB514 cannot occur at the same time if the material in the tank produces a hydrogen sulfide head space concentration of greater than 50 ppmv.

D. Emissions from tanks with landed roofs being filled with liquids that generate hydrogen sulfide concentrations greater than 10 ppmv in the landed roof headspace (crude oil, sour water and sour intermediates) shall be routed to a control device meeting the requirements of Special Condition 51. The following applies to tanks within 750 feet of the property line that may have a hydrogen sulfide head space concentration greater than 50 ppmv.

(1) If filling a tank with a landed roof not following a tank degassing/cleaning, the fill rate will be lowered so that the hourly sulfur dioxide emission rate is at or below 4.44 lb/hr.

(2) Degassing of these tanks shall not occur while controlling the filling one of these tanks that had not been degassed and cleaned.

E. The permit holder shall determine the potential hydrogen sulfide generated during tank refilling as reference in parts C and D of this condition by sampling the vapors when the liquid level is at approximately half the height of the landed roof and when the liquid level is within 10 percent of the height of the landed roof. The sampling shall be performed in accordance with Special Condition 42.B with the exception of 42.B.(3). This determination shall be made at least once for each type of liquid.

49. The MSS activities represented in the permit application may be authorized under permit by rule only if the procedures, emission controls, monitoring, and recordkeeping are the same as those required by this permit.

50. All permanent facilities must comply with all operating requirements, limits, and representations during planned startup and shutdown unless alternate requirements and limits are identified in this permit. Alternate requirements for emissions from routine emission points are identified below:

A. Combustion units, with the exception of flares, at this site are exempt from NO_x and CO-operating requirements identified in special conditions and representations during planned maintenance, startup, and shutdown if the following criteria are satisfied.

(1) The emission caps or maximum allowable emission rates in the permit authorizing the facility are not exceeded.

(2) The start-up period does not exceed in duration as listed in the following table and the firing rate does not exceed 75 percent of the design firing rate. The time it takes to complete the shutdown does not exceed 4 hours. For maintenance events occurring while a combustion source is in normal operation, the maintenance period shall not exceed the startup duration.

EPN	Source Name	Startup Duration (hrs)*
D-3, 04BA4ST	Cumene Hot Oil Heater	36
B-1A, B	Coker Charge Heater	19
II-7	HDC Splitter Heaters	24
N-103	Parex #2 Hot Oil Heater	12
N-104	MSTDP Reactor Heater	12
KK-3	GOHT Charge Heater	13
JJ-2	CCR Charge Heaters	40
JJ-6	Xylene Column Reboiler	12
A-103, 40BA101ST	West Crude Heater	44
A-103, 40BA401ST	West Vacuum Heater	46
A-203	Mid Crude Heater	44
A-204	Mid Vacuum Heater	46
LSGHTR	LSG Hot Oil Heater	36
MX-1	MX Unit Hot Oil Heater	10
DDS-HTRSTK	DDS Charge heater	14
DDS-HTRSTK	DDS Fractionator Reboiler	14
N-3, 61BA1201ST	Parex #1 Hot Oil (Raffinate) Heater	12
N-3, 61BA1202ST	Parex #1 Hot Oil (Extract) Heater	12
Various	All combustion sources not listed in this table or special condition, except flares	8
* The beginning of Combustion Source Startup is defined as when the first burner is lit		

(3) Control devices are started and operating properly when venting a waste gas stream.

B. The limits identified below apply to the operations of the specified facilities during startup and shutdown.

(1) The FCC startup emissions shall be routed to the operating FCC scrubber and the hourly average pollutant concentrations shall be less than those specified for normal

operations in Special Conditions 20, 21, and 22. FCC preheat emissions may exhaust through EPN FCCURXVENT. Refractory cure emissions may exhaust through EPN FCCURCVENT.

(2) The SRU incinerators (EPNs H-15B and H-15C) shall oxidize at least 99.9 percent of the hydrogen sulfide directed to them to sulfur dioxide during the SRU start-up evolution. SRU seal legs may vent to atmosphere during seal leg, sulfur pit or eductor maintenance. The minimum sulfur recovery efficiency and exhaust concentrations specified for normal operations in Permit 8803A do not apply during periods of start-up or shutdown.

(3) The flare gas recovery unit shutdown shall be planned for periods when the flare system will not be utilized to control planned process unit MSS.

(4) Decoking of the heaters identified in the following table shall be performed using the shot blast, pigging, or burn-out techniques. The PM emissions shall be controlled by cyclones to less than 0.01 grain/scf when using the shot blast technique.

FIN	EPN	Description
42BA1	41BA1MSS	Decoking for Mid-Crude Charge Heater
42BA3	42BA3MSS	Decoking for Mid-Crude Vacuum Heater
40BA101	40BA101MSS	Decoking for West Crude Charge Heater
40BA401	40BA401MSS	Decoking for West Crude Charge Heater
16BA1601	16BA1601MS	Decoking for Coker Charge Heater

(5) The MSTDP catalyst shall be purged with nitrogen to the flare gas recovery unit prior to purging the reactor with air to a flare. The air purge shall be directed to the flare until the VOC concentration is less than 10,000 ppmv. The new or regenerated catalyst shall be conditioned with the exhaust routed to a flare.

(6) Sulfur terminal MSS: The sulfur degassing pit vents shall be covered, and sulfur shall not be loaded into the degassing pit while flushing the LO-CAT mobile bed absorber. The sulfur degassing pit shall be isolated during cleaning of the LO CAT unit.

C. The LEU Hot Oil Heater is exempt from the operating requirements identified in these SC during planned MSS on the heater, combustion catalyst, or the SCR control system if the following criteria are satisfied (as applicable):

(1) The MSS emission caps in the MAERT are not exceeded.

(2) The bypass of the combustion catalyst and SCR control systems for maintenance does not exceed 408 hours in a rolling 12-month period.

(3) The start-up period of the heater shall not exceed 10 hours per event, and the firing rate does not exceed 75 percent of the design firing rate. The time to complete shutdown of the heater shall not exceed 4 hours per event. Except as specified in C(2) of this condition, maintenance events which occur while the combustion source is in normal operation shall not exceed 10 hours per event.

D. The CCR Hot Oil Heater and NHT Charge Heater are exempt from the operating requirements identified in these SC during planned MSS on either heater or the SCR control system if the following criteria are satisfied (as applicable):

(1) The MSS emission caps in the MAERT are not exceeded.

(2) The bypass of the SCR control system for maintenance does not exceed 144 hours in a rolling 12-month period.

(3) The start-up period of the heater shall not exceed 10 hours per event, and the firing rate does not exceed 75 percent of the design firing rate. The time to complete shutdown of the heater shall not exceed 4 hours per event. Except as specified in D(2) of this condition, maintenance events which occur while the combustion source is in normal operation shall not exceed 10 hours per event.

E. The CCR Auxiliary Heater is exempt from the operating requirements identified in these SC during planned MSS on the heater or the SCR control system if the following criteria are satisfied (as applicable):

(1) The MSS emission caps in the MAERT are not exceeded.

(2) The shutdown of the SCR control system for maintenance does not exceed 144 hours in a rolling 12-month period.

(3) The start-up period of the heater shall not exceed 40 hours per event, and the firing rate shall not exceed 75 percent of the design firing rate. The time to complete shutdown of the heater shall not exceed 40 hours per event. Except as specified in E.(2) of this condition, maintenance events which occur while the combustion source is in normal operation shall not exceed 10 hours per event.

F. A record shall be maintained indicating that the start and end times each of the activities identified above occur and documentation that the requirements for each have been satisfied.

51. Control devices required by this permit for emissions from planned MSS activities are limited to those types identified in this condition. Control devices shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours.

Each device used must meet all the requirements identified for that type of control device. Controlled recovery systems identified in this permit shall be directed to an operating refinery process or to a collection system that is vented through a control device meeting the requirements of this permit condition.

A. Carbon Adsorption System (CAS):

(1) The CAS shall consist of 2 carbon canisters in series with adequate carbon supply for the emission control operation.

(2) The CAS shall be sampled downstream on the first can and the concentration recorded at least once every hour of CAS run time to determine breakthrough of the VOC. The sampling frequency may be extended using either of the following methods:

(a) It may be extended to up to 30 percent of the minimum potential saturation time for a new can of carbon. The permit holder shall maintain records including the calculations performed to determine the minimum saturation time.

(b) The carbon sampling frequency may be extended to longer periods based on previous experience with carbon control of a MSS waste gas stream. The past experience must be with the same VOC, type of facility, and MSS activity. The basis for the sampling frequency shall be recorded. If breakthrough is monitored on the initial sample of the upstream can when the polishing can is put in place, a permit deviation shall be recorded.

(3) The method of VOC sampling and analysis shall be by detector meeting the requirements of Special Condition 42.

(4) Breakthrough is defined as the highest measured VOC concentration at or exceeding 100 ppmv above background. When the condition of breakthrough of VOC from the initial saturation canister occurs, the waste gas flow shall be switched to the second canister and a fresh canister shall be placed as the new final polishing canister within four hours or prior to the next required sample, whichever is greater. In lieu of replacing canisters, the flow of waste gas may be discontinued until the canisters are switched. Sufficient new activated carbon canisters shall be maintained at the site to replace spent carbon canisters such that replacements can be done in the above specified time frame.

(5) Records of CAS monitoring shall include the following:

(a) Sample time and date.

(b) Monitoring results (ppmv).

(c) Canister replacement log.

(6) Single canister systems are allowed if the time the carbon canister is in service is limited to no more than 30% of the minimum potential saturation time. The permit holder shall maintain records for these systems, including the calculations performed to determine the saturation time. The time limit on carbon canister service shall be recorded and the expiration date attached to the carbon can.

B. Thermal Oxidizer.

(1) The thermal oxidizer firebox exit temperature shall be maintained at not less than 1400°F and waste gas flows shall be limited to assure at least a 0.5 second residence time in the fire box while waste gas is being fed into the oxidizer.

(2) The thermal oxidizer exhaust temperature shall be continuously monitored and recorded when waste gas is directed to the oxidizer. The temperature measurements shall be made at intervals of six minutes or less and recorded at that frequency. Temperature measurements recorded in continuous strip charts may be used to meet the requirements of this section.

The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have an accuracy of the greater of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5ºC.

C. Internal Combustion Engine.

(1) Internal combustion engine shall have a VOC destruction efficiency of at least 99%.

(2) The engine must have been stack tested with propane or butane to confirm the required destruction efficiency within the past 12 months. VOC shall be measured in accordance with the applicable United States Environmental Protection Agency (EPA) Reference Method during the stack test and the exhaust flow rate may be determined from measured fuel flow rate and measured oxygen concentration. A copy of the stack test report shall be maintained with the engine. There shall also be documentation of acceptable VOC emissions following each occurrence of engine maintenance which may reasonably be expected to increase emissions including oxygen sensor replacement and catalyst cleaning or replacement. Stain tube indicators specifically designed to measure VOC concentration shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable VOC analyzers meeting the requirements of Special Condition 42 are also acceptable for this documentation.

(3) The engine shall be operated with an oxygen sensor-based air-to-fuel ratio (AFR) controller. Documentation for each AFR controller that the manufacturer's, or supplier's recommended maintenance has been performed, including replacement of the oxygen sensor as necessary for oxygen sensor-based controllers shall be maintained with the engine. The oxygen sensor shall be replaced at least quarterly in the absence of a specific written recommendation.

D. The plant flare system operated as required by Permit 8803A.

E. Scrubbers and/or absorbers may be used upstream of any control device listed in this special condition to enhance VOC and/or H_2S capture provided such systems are closed systems and the spent absorbing solution is discharged into a closed container, vessel, or system.

52. No visible emissions shall leave the property due to abrasive blasting.

53. Black Beauty, Garnet Sand, and coal slag may be used for abrasive blasting. The permit holder may also use blast media that meet the criteria below:

A. The media shall not contain asbestos or greater than 1.0 weight percent crystalline silica.

B. The weight fraction of any metal in the blast media with a short-term effects screening level (ESL) less than 50 micrograms per cubic meter as identified in the most recently published TCEQ ESL list shall not exceed the ESLmetal/1000.

C. The MSDS for each media used shall be maintained on site.

Blasting media usage and the associated emissions shall be recorded each month and the rolling 12-month total emissions updated.

Recordkeeping Summary

54. Records shall be maintained by the holder of this permit in a form suitable for inspection for a period of five years after collection and shall be made available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction. **(03/23)**

55. Modifications evaluated under the actuals-to-projected actuals (ATPA) applicability test.

A. The permit holder shall comply with the monitoring, recordkeeping and reporting requirements of 30 TAC §116.127 with respect to the facilities identified in the following paragraphs.

B. The modification authorized by permit amendment (application received February 24, 2017), which revise a prior permit application representation and thereby allow multiple SRU MSS.

The projected actual emissions for facilities where the SRU MSS applicability test has been employed are as follows:

Source Name	Facility Name	Air Contaminant	Projected Actual Emission rate (tons per year)
SRU MSS	Planned MSS Emissions	PM	0.01
		PM_{10}	0.01
		$PM_{2.5}$	0.01
		VOC	0.01
		NO_x	0.10

		CO	0.55
		SO_2	15.88
		H_2S	0.01

Total actual emissions from the referenced facilities shall be monitored and recorded in accordance with Title 30 of the Texas Administrative Code (30 TAC) §116.127(b).

56. An Alternative Method of Compliance (AMOC) to use the combined NHT Charge Heater and CCR Hot Oil Heater exhaust (waste) stream from EPN JJ-4 for comparison to the 40 CFR 60 Subpart Db NO_x standard (only applicable to the CCR Hot Oil Heater), was reviewed and approved by TCEQ APD on February 13, 2018.

57. An AMOC to exempt the LEU Hot Oil Heater (EPN LEUHOH) from SO_2 monitoring under 40 CFR 60 Subpart Ja, was reviewed and approved by TCEQ APD on April 11, 2018.

58. An AMOC to exempt the Low Sulfur Gasoline Hot Oil Heater (EPN LSGHTR) from SO_2 monitoring under 40 CFR 60 Subpart J, was reviewed and approved by TCEQ APD on September 14, 2018.

59. Modifications evaluated under the actuals-to-projected actuals (ATPA) applicability test.

    A. The permit holder shall comply with the monitoring, recordkeeping and reporting requirements of 30 TAC §116.127 with respect to the facilities identified in the following paragraphs.

    B. The permit amendment, application received October 10, 2017, authorizes modifications for the Low Sulfur Bunker Fuels Project.

    The projected actual emissions for facilities where the ATPA applicability test has been employed are as follows:

Permit No.	Source Name	Facility Name	Air Contaminant	Projected Actual Emission rate (tons per year)
8803A	B-2	Coker Reboiler	NO_x	7.14
			CO	6.00
			SO_2	1.28
			PM	0.54
			PM_{10}	0.54
			$PM_{2.5}$	0.54
			VOC	0.39
8803A	CKH-1	Coke Handling	PM	2.03
			PM_{10}	2.03
			$PM_{2.5}$	2.03
6819A	AA-4	FCCU CO Boiler/Scrubber	NO_x	413.10
			SO_2	135.11

Total actual emissions from the referenced facilities shall be monitored and recorded in accordance with Title 30 of the Texas Administrative Code (30 TAC) §116.127(b).

60. For permit amendment (initial application received October 10, 2017) authorizing the Low Sulfur Bunker Fuels Project, the incremental increase in emissions methodology was used for the following non-modified affected facilities to determine the difference between projected actual emissions and baseline actual emissions while excluding emissions following the project that the facilities could have accommodated and that are unrelated to the project:

EPN	Facility
FB506R1 and FB3042	Tanks 15FB506R1 and 40FB3042
FB4014	Tank 40FB4014
FB3043, FB3045, FB3046, and FB3047	Tanks 40FB3043, 40FB3045, 40FB3046, and 40FB3047
R-7, R-8, and R-9	Boilers
W-8	Uncontrolled Marine Loading

For each of these facilities, the permit holder shall calculate and maintain a record of the incremental annual emissions increase resulting from the Low Sulfur Bunker Fuels Project, in tons per year, on a calendar year basis, for a period of five years following resumption of regular operations following the Low Sulfur Bunker Fuels Project. The permit holder shall submit a report to the Executive Director if the actual emissions from the project exceed the baseline actual emissions by a significant amount for that pollutant, and the incremental increase in emissions from any of these facilities exceeds the incremental increase represented in the permit amendment application. The report shall be submitted to the Executive Director within 60 days of the calendar year and shall contain:

(1) The name, address and telephone number of the major stationary source; and

(2) The calculated incremental emissions increases.

The permit holder shall make the information required to be documented and maintained by this special condition available for review upon the request of the Executive Director or local air pollution control program.

61. The CCR Improvements Project authorized by the amendment application, PI-1 dated December 13, 2019, is determined not to be subject to major new source review by identifying projected actual emission rates for the following facilities potentially affected by the project.

EPN	Pollutant	Projected Actuals (tpy)
JJ-6	NO_x	28.49
	CO	28.49
	SO_2	11.20
	PM	2.85
	PM_{10}	2.85
	$PM_{2.5}$	2.85
	VOC	3.41

Actual emissions from the referenced facilities shall be monitored (or calculated if no CEMS is required), recorded and reported in accordance with Title 30 of the Texas administrative Code (30 TAC) § 116.127(b), (d).

62. An AMOC to use ASTM D 1946 and 3588 fuel analysis methods for the following applicable sources to determine a fuel specific “F-factor” for compliance with 40 CFR 60 Subparts Db or Ja, was reviewed and approved by TCEQ APD on February 25, 2020:

EPN	Source Name	FIN	Fuel Gas used
R-201	Midplant Boiler	43BF1	MP Refinery Fuel Gas (RFG) - mixture of purchased natural gas, 90# RFG, and off-gases from various process units
LSGHTR	LSG Hot Oil Heater	47BA1	
LEUHOH	LEU Hot Oil Heater	42BA5	Purchased natural gas, but may be configured to combust RFG at some future date
JJ-4	CCR Hot Oil Heater	39BA3901	CCR RFG - mixture of 90# RFG, purchased natural gas, and off-gases from various process units
DDS-HTRSTK	DDS Charge Heater	56BA1	MP RFG
	DDS Fractionator	56BA2	

Referenced Permits by Rule (PBR)

63. The following sources and/or activities are authorized under a Permit by Rule (PBR) by Title 30 Texas Administrative Code Chapter 106 (30 TAC Chapter 106). These lists are not intended to be all inclusive and can be altered without modifications to this permit. **(03/23)**

Authorization	Source / Activity
PBR No. 159212	Fugitive components in the DHT Unit (FIN 37), Mid Crude Unit (FIN 42), Oil Movements Area (FIN P-VOC), site-wide NH3 and H2S fugitive emissions (FINS F-NH3 and F-H2S) associated with Gas Oil Hydrotreater (GOHT) to Diesel Hydrotreater (DHT) Conversion Project.
PBR No. 159237	Fugitive components in the FCC Unit (FIN 01) associated with West Fluidized Catalytic Cracking Unit Revamp Project.
PBR No. 164418	Fugitive components in the West Truck Rack (FIN F-101) and New Loading Bay 4 (FIN TR-101BAY4) associated with West Truck Rack Project.

Date: June 12, 2025

Attachment A

Permit Numbers 6819A, 8803A, and PSDTX413M9

Inherently Low Emitting Activities

Activity	VOC	NO_x	CO	PM	H_2S/SO_2
Water washing of equipment	x				x
Combustion shut off devices	x				x
Aerosol Cans Degassing/Crushing	x				
Inspection, maintenance, blowdown, repair, replacement, adjustment, testing and calibration of instrumentation/analyzer/analytical equipment	x	x	x		x
Materials Handling (i.e. Catalyst, insulation, clay, lime, sand, carbon, salt, refractory handling)	x			x	
Removal of Sulfur Deposits from LO-CAT System					x
Shot Blasting of Heater Tubes				x	
Inspection, maintenance, repair and replacement of carbon canisters	x				x
Pan emissions associated with inspection, maintenance, blowdown, repair and replacement of filters, screens, baskets, strainers, water circulating systems (cooling, boiler, potable), monitoring/measuring equipment (e.g., sight glasses, rotometers, meter proving); exchanger backflushes; deadleg blowdowns; salt dryer inspection/refills; oil changes on pumps and other small motors; pump seal, pump case, seal cooler replacements	x				x
Combinations of the above	x		x	x	x

Date: September 20, 2024

Attachment B

Permit Numbers 6819A, 8803A, and PSDTX413M9

Routine Maintenance Activities

Pump, compressor, vessel, exchanger, fugitive, component (valve, pipe, or flange) repair/replacement, or combinations of the preceding not included in Attachment A.

Date: January 28, 2021

Attachment C

Permit Numbers 6819A, 8803A, and PSDTX413M9

MSS Activity Summary

Facilities	Description	Emissions Activity	EPN
all process units	process unit shutdown / depressurize / drain	vent to flare gas recovery unit (FGRU) or flare*	MSSFLR
all process units	process unit purge / degas / drain	vent to atmosphere	MSSATM
all process units	process unit start-up	vent to FGRU or flare*	MSSFLR
all process units and tanks	preparation for facility / component repair / replacement	vent to FGRU or flare*	MSSFLR
all process units and tanks	preparation for facility / component repair / replacement	vent to atmosphere	MSSATM
all process units and tanks	recovery from facility / component repair / replacement	vent to FGRU, flare* or control device	MSSFLR
all process units and tanks	recovery from facility / component repair / replacement	vent to atmosphere	MSSATM
all process units and tanks	preparation for unit turnaround or facility / component repair / replacement	remove liquid	MSSATM
FCC	Start-up / shutdown / vent	warm up, refractory cure, and start-up with torch oil, and vent reactor	MSSPRO
all floating roof tanks	tank roof landing	operation with landed roof	MSSATM
all floating roof tanks	degas of tank with landed roof	controlled degassing	MSSATM
SRU	Start-up / shutdown / meltout	vent directly to incinerator on start-up and meltout	MSSPRO
SRU seal legs	Periodic seal leg, sulfur pit and eductor maintenance	seal leg vapors vent to atmosphere instead of the incinerator (via sulfur pit)	MSSATM
see Attachment A	miscellaneous low emitting activities	see Attachment A	MSSATM
all production-related	abrasive blasting	PM from blasting media	MSSATM
Cogen (EPN Z-4)**	turbine startup/shutdown	turbine start-up/shutdown	MSSCAP
sulfur terminal	LO-CAT daily and quarterly maintenance	degassing pit vents not direct to LO-CAT	MSSATM
MSTDP	catalyst regeneration / replacement	initially vented to flare gas recovery system, then flare, and atmosphere	MSSPRO
furnaces identified in SC33	Decoke		

* Material shall not be directed to a flare unless the FGRU is undergoing planned MSS or in the event the FGRU capacity is exceeded.
** Consolidated from TCEQ SP 130259

Date: January 28, 2021

Attachment D

Permit Number 6819A

Requirements for Cooling Towers

Leaks into Cooling Towers

FHR shall follow the procedures outlined in this paragraph for addressing any benzene associated with leaks of process fluids into non-contact, recirculating cooling tower systems (herein referred to as cooling tower systems)

i. Applicability. The monitoring and sampling requirements of this paragraph shall apply to all cooling tower systems that have the potential to come in contact with process fluids that have a benzene content of 0.1 wt% or greater. The potential to come in contact is present because of the possibility of process leaks even if the system is considered non- contact.

ii. Daily Parametric Monitoring. FHR shall perform at least one of the following types of parametric monitoring daily for each of the affected cooling tower systems:(A) Visual or olfactory observations for hydrocarbons; (B) Chemical use mass balance; (C) Microbiological growth detection; or (D) pH monitoring. If the results of such monitoring, alone or in conjunction with other process knowledge, indicate the likely presence of benzene in excess of 1 ppmw in the cooling water, FHR shall obtain three representative samples of water from a cooling tower riser located at the potentially-impacted cooling tower(s) within 24 hours, and shall transmit the samples within 72 hours by next day delivery to an external lab for analysis utilizing one of the test methods in 40 C.F.R. Sec. 61.355(c)(3)(iv).

iii. Detection of Benzene in Cooling Water. Once FHR has detected the presence of benzene greater than 1 ppmw in the cooling water prior to entering a cooling tower riser as provided in subparagraph (b)(ii), additional water samples required by subparagraph (b)(ii) are not needed until such time after the source of the benzene has been repaired, even though subsequent parametric monitoring (e.g., pH monitoring) conducted up to and until the repair continues to indicate the presence of benzene. FHR shall collect and analyze additional water samples in accordance with subparagraph (b)(ii) if parametric monitoring or other process knowledge indicates that a new leak has likely occurred.

iv. FHR shall monitor the exhaust of each of its applicable cooling water strippers for VOC content once per calendar month. If a VOC reading is greater than 5 ppmv, and/or any other process knowledge indicates the likely presence of benzene in excess of 1 ppmw in the cooling water, FHR shall obtain three representative samples of the water entering the potentially impacted cooling tower and will transmit such samples within 24 hours by next day delivery to the external lab for analysis using one of the test methods in 40 C.F.R. Sec. 61.355(c)(3)(iv). Once a leak has been identified and until it has been repaired, subsequent VOC monitoring that continues to indicate the same leak does not give rise to a requirement to obtain additional water samples, except as needed by FHR to determine if the leak has changed or unless VOC monitoring or process knowledge indicates that a new leak likely has occurred.

v. Repair Deadline for Confirmed Leak. If FHR determines, through the water sampling and benzene analyses referenced in paragraphs (ii), (iii), or (iv), that a leak from process equipment has caused the benzene concentration in the cooling water prior to entering the cooling towers to exceed 1 ppmw, FHR shall repair the leak within 45 days after the date that FHR identifies the equipment that is leaking. FHR shall make all reasonable efforts to identify the leaking equipment as expeditiously as possible, but in no case shall the identification period exceed 30 days from the date the laboratory analysis indicates that there is the presence of benzene in excess of 1 ppmw in the cooling tower system. The period to identify a leak may be extended beyond 30 days upon the consent of TCEQ.

vi. Exclusions to the Repair Deadline. This 45-day deadline to repair is not applicable if one or more of the following criteria is met:

(A). The equipment that is causing the leak is isolated from the process as soon as practical, but no longer than 45 days from when FHR identified the leaking equipment;

(B). The necessary parts are not reasonably available (in which case, the repair must be completed within 120 days of the date the leaking equipment is identified);

(C). Shutdown of the affected unit is already planned to occur within 60 days from the date the leaking equipment is identified;

(D). Shutdown for repair would cause greater emissions than the potential emissions that would result from a delay of repair (in which case FHR must make that calculation prior to relying on this exemption);

(E). The process fluid has been prevented from leaking into the cooling tower system via a process or system change; or

(F). Subsequent samples (utilizing 2 representative samples) confirm that the concentration of benzene in the cooling water prior to the cooling tower is less than 1 ppmw.

vii. Confirmation of Repair. Once FHR has identified and corrected a leak pursuant to (v) above, it shall conduct water sampling within 14 days of the repair or startup, whichever is later, to confirm that the benzene concentration in the cooling water prior to the cooling towers is less than 1 ppmw. The confirmation sampling may occur later if more time is needed to obtain a reliable sample due to water quality problems. At no time shall the confirmation sampling exceed 30 days after the repair or startup. If the confirmation sampling demonstrates that there is still a leak in the cooling tower system above 1 ppmw, then a new 45-day repair deadline shall commence on the date of such confirmation.

Date: January 28, 2021