TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

August 21, 2012

MR FORREST LAUHER
GENERAL MANAGER
MOTIVA ENTERPRISES LLC
PO BOX 712
PORT ARTHUR TX 77641-0712

HSSE DEPARTMENT

Manager		Mgr-Tech Env
HSS Mgr	AUG 2 4 2012	Mgr-Env Assurance
Env Mgr		Team Lead-ERO
H&S Mgr		Team Ldr-LDAR
Sec Mgr		Admin-Files
Admin		File No.

File 2.F.04

Re: Permit Amendment Applications
Permit Number: 8404
Port Arthur Refinery Base Plant
Port Arthur, Jefferson County
Regulated Entity Number: RN100209451
Customer Reference Number: CN600124051
Account Number: JE-0095-D

Dear Mr. Lauher:

This is in response to your letter received March 31, 2011 and your Form PI-1's (General Application for Air Preconstruction Permits and Amendments) concerning the proposed amendments to Permit Number 8404. First, we understand that you propose to raise the short term emission rates of various heaters at the refinery. Secondly, you requested an amendment of Air Quality Permit Number 8404, issued under Title 30 Texas Administrative Code Chapter 116 (30 TAC Chapter 116), Subchapter G (Flexible Permits), to an air quality permit issued under 30 TAC Chapter 116, Subchapter B (New Source Review Permits).

As indicated in Title 30 Texas Administrative Code § 116.116(b) and § 116.160 [30 TAC § 116.116(b) and § 116.160], and based on our review, Permit Number 8404 is hereby amended. In addition, with this permitting action, Permit by Rule Registration Numbers 89645, 92158, 92603, and 93766 have been voided. This information will be incorporated into the existing permit file. A permit issued under 30 TAC Chapter 116, Subchapter B (New Source Review Permits) for your facility is enclosed. The permit contains several general and special conditions that define the level of operation and MAERT. We appreciate your careful review of the special conditions of the permit and assuring that all requirements are consistently met.

Planned maintenance, startup, and shutdown for the sources identified on the MAERT have been reviewed and included in the MAERT and specific maintenance activities are identified in the permit special conditions. Any other maintenance activities are not authorized by this permit and will need to obtain separate authorization.

You may file a **motion to overturn** with the Chief Clerk. A motion to overturn is a request for the commission to review the executive director's decision. Any motion must explain why the commission should review the executive director's decision. According to 30 TAC § 50.139, an action by the executive director is not affected by a motion to overturn filed under this section unless expressly ordered by the commission.

Re: Permit Number: 8404

A motion to overturn must be received by the Chief Clerk within 23 days after the date of this letter. An original and 11 copies of a motion must be filed with the Chief Clerk in person, or by mail to the Chief Clerk's address on the attached mailing list. On the same day the motion is transmitted to the Chief Clerk, please provide copies to the applicant, the executive director's attorney, and the Public Interest Counsel at the addresses listed on the attached mailing list. If a motion to overturn is not acted on by the commission within 45 days after the date of this letter, then the motion shall be deemed overruled.

You may also request **judicial review** of the executive director's approval. According to Texas Health and Safety Code § 382.032, a person affected by the executive director's approval must file a petition appealing the executive director's approval in Travis County district court within 30 days after the **effective date of the approval**. Even if you request judicial review, you still must exhaust your administrative remedies, which includes filing a motion to overturn in accordance with the previous paragraphs.

Your cooperation in this matter is appreciated. If you need further information or have any questions, please contact Dr. Kurt Kind, Ph.D., P.E. at (512) 239-1337 or write to the Texas Commission on Environmental Quality, Office of Air, Air Permits Division, MC-163, P.O. Box 13087, Austin, Texas 78711-3087.

This action is taken under authority delegated by the Executive Director of the TCEQ.

Sincerely,

Michael Wilson

Michael Wilson, P.E., Director
Air Permits Division
Office of Air
Texas Commission on Environmental Quality

MPW/kk

Enclosures

cc: Air Section Manager, Region 10 - Beaumont

Project Number: 164529

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
AIR QUALITY PERMIT

A PERMIT IS HEREBY ISSUED TO
Motiva Enterprises LLC
AUTHORIZING THE CONSTRUCTION AND OPERATION OF
Port Arthur Refinery Base Plant
LOCATED AT **Port Arthur, Jefferson County, Texas**
LATITUDE 29° 52′ 59″ LONGITUDE 93° 57′ 59″

1. **Facilities** covered by this permit shall be constructed and operated as specified in the application for the permit. All representations regarding construction plans and operation procedures contained in the permit application shall be conditions upon which the permit is issued. Variations from these representations shall be unlawful unless the permit holder first makes application to the Texas Commission on Environmental Quality (commission) Executive Director to amend this permit in that regard and such amendment is approved. [Title 30 Texas Administrative Code § 116.116 (30 TAC § 116.116)]

2. **Voiding of Permit.** A permit or permit amendment is automatically void if the holder fails to begin construction within 18 months of the date of issuance, discontinues construction for more than 18 months prior to completion, or fails to complete construction within a reasonable time. Upon request, the executive director may grant an 18-month extension. Before the extension is granted the permit may be subject to revision based on best available control technology, lowest achievable emission rate, and netting or offsets as applicable. One additional extension of up to 18 months may be granted if the permit holder demonstrates that emissions from the facility will comply with all rules and regulations of the commission, the intent of the Texas Clean Air Act (TCAA), including protection of the public's health and physical property; and (b)(1)the permit holder is a party to litigation not of the permit holder's initiation regarding the issuance of the permit; or (b)(2) the permit holder has spent, or committed to spend, at least10 percent of the estimated total cost of the project up to a maximum of $5 million. A permit holder granted an extension under subsection (b)(1) of this section may receive one subsequent extension if the permit holder meets the conditions of subsection (b)(2) of this section. [30 TAC § 116.120(a), (b) and (c)]

3. **Construction Progress.** Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office of the commission not later than 15 working days after occurrence of the event. [30 TAC § 116.115(b)(2)(A)]

4. **Start-up Notification.** The appropriate air program regional office shall be notified prior to the commencement of operations of the facilities authorized by the permit in such a manner that a representative of the commission may be present. The permit holder shall provide a separate notification for the commencement of operations for each unit of phased construction, which may involve a series of units commencing operations at different times. Prior to operation of the facilities authorized by the permit, the permit holder shall identify to the Chief Engineer's Office the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program).

5. **Sampling Requirements.** If sampling is required, the permit holder shall contact the commission's Office of Compliance and Enforcement prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The permit holder is also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant. [30 TAC § 116.115(b)(2)(C)]

6. **Equivalency of Methods.** The permit holder must demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the permit. Alternative methods shall be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the permit. [30 TAC § 116.115(b)(2)(D)]

7. **Recordkeeping.** The permit holder shall maintain a copy of the permit along with records containing the information and data sufficient to demonstrate compliance with the permit, including production records and operating hours; keep all required records in a file at the plant site. If, however, the facility normally operates unattended, records shall be maintained at the nearest staffed location within Texas specified in the application; make the records available at the request of personnel from the commission or any air pollution control program having jurisdiction; comply with any additional recordkeeping requirements specified in special conditions attached to the permit; and retain information in the file for at least two years following the date that the information or data is obtained. [30 TAC § 116.115(b)(2)(E)]

8. **Maximum Allowable Emission Rates.** The total emissions of air contaminants from any of the sources of emissions must not exceed the values stated on the table attached to the permit entitled "Emission Sources--Maximum Allowable Emission Rates." [30 TAC § 116.115(b)(2)(F)]

9. **Maintenance of Emission Control.** The permitted facilities shall not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. The permit holder shall provide notification for upsets and maintenance in accordance with §§ 101.201, 101.211, and 101.221 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements; and Operational Requirements). [30 TAC § 116.115(b)(2)(G)]

10. **Compliance with Rules.** Acceptance of a permit by an applicant constitutes an acknowledgment and agreement that the permit holder will comply with all rules, regulations, and orders of the commission issued in conformity with the TCAA and the conditions precedent to the granting of the permit. If more than one state or federal rule or regulation or permit condition is applicable, the most stringent limit or condition shall govern and be the standard by which compliance shall be demonstrated. Acceptance includes consent to the entrance of commission employees and agents into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the permit. [30 TAC § 116.115(b)(2)(H)]

11. This permit may be appealed pursuant to 30 TAC § 50.139.

12. This permit may not be transferred, assigned, or conveyed by the holder except as provided by rule. [30 TAC § 116.110(e)]

13. There may be additional special conditions attached to a permit upon issuance or modification of the permit. Such conditions in a permit may be more restrictive than the requirements of Title 30 of the Texas Administrative Code. [30 TAC § 116.115(c)]

14. **Emissions** from this facility must not cause or contribute to a condition of "air pollution" as defined in TCAA § 382.003(3) or violate TCAA § 382.085, as codified in the Texas Health and Safety Code. If the executive director determines that such a condition or violation occurs, the holder shall implement additional abatement measures as necessary to control or prevent the condition or violation.

PERMIT 8404

Date: November 15, 2006

Zak Covar

For the Commission

SPECIAL CONDITIONS

Permit 8404

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. The portion of the MAERT labeled "Before CEP" shall be applicable prior to the introduction of feed to a new major Crude Expansion Unit (DCU2, HCU2, NPC, or VPS5). The portion of the MAERT labeled "After CEP" shall be applicable upon introduction of feed to a new major Crude Expansion Unit (DCU2, HCU2, NPC, or VPS5).

Storage Of Volatile Organic Compounds (VOC)

2. Storage tanks are subject to the following requirements. The control requirements specified in paragraphs A-E of this condition shall not apply (1) where the VOC has an aggregate partial pressure of less than 0.50 pounds per square inch, absolute (psia) at the maximum expected operating temperature or 95°F, whichever is greater, or (2) to storage tanks smaller than 25,000 gallons.

   A. An internal floating deck or "roof" or equivalent control shall be installed in all tanks. 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 internal floating roof: (1) a liquid-mounted seal, (2) two continuous seals mounted one above the other, or (3) a mechanical shoe seal.

   B. An open-top tank containing a floating roof (external floating roof tank) which uses double seal or secondary seal technology shall be an approved control alternative to an internal floating roof tank 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. Routing of tank emissions to the existing vapor recovery system is an approved alternative control.

   C. For any tank equipped with a floating roof, the permit holder shall perform the visual inspections and seal gap measurements as 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) to verify fitting and seal integrity. Records shall be maintained of the dates seals were inspected and seal gap measurements made, results of inspections and measurements made (including raw data), and actions taken to correct any deficiencies noted.

D. 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.

E. Except for logos, slogans, and similar displays (not to exceed 15 percent of the vertical tank shell area), uninsulated tank exterior surfaces exposed to the sun shall be white or 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 previous rolling 12-month period. The 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, VOC throughput for the previous month and rolling 12-month period. 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 for tanks shall be calculated using the Texas Commission on Environmental Quality (TCEQ) publication dated February 2001, titled "Technical Guidance Package for Chemical Sources - Storage Tanks," and U.S. Environmental Protection Agency (EPA) Tanks Program Version 4.09d based on AP-42 "Compilation of Air Pollutant Emission Factors," Section 7.1.

VOC Loading And Unloading Operations

3. The following shall apply to railcar and truck loading and unloading (unloading at LR4 rack only) operations: **(8/07)**

A. At the LR4 loading rack all vessels to be loaded or unloaded, and at the CDTECH loading racks all vessels to be loaded, and all associated piping and connections at both racks, shall be pressure-rated (minimum 30 psig). Displaced loading vapors shall be routed to the vapor recovery system. All lines 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 during loading operations.

B. At the LR39 loading rack the following shall apply:

(1) All loading shall be submerged and rolling 12-month rack throughput records shall be updated on a monthly basis for each product loaded.

(2) The permit holder shall maintain and update monthly an emissions record which includes calculated emissions of VOC from all 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. Emissions shall be calculated using the TCEQ publication titled "Technical Guidance Package for Chemical Sources - Loading Operations," dated October 2000.

C. All lines 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 during loading operations.

Operating Parameters And Conditions

4. Non-fugitive emissions from relief valves, safety valves, or rupture discs of gases containing VOC at a concentration of greater than one weight percent are not authorized by this permit unless listed with associated individual emission limitations in the table entitled "Emission Sources – Emission Caps and Individual Emission Limitations." Any releases directly to atmosphere from relief valves, safety valves, or rupture discs of gases containing VOC at a concentration of greater than 1 weight percent are not consistent with good practice for minimizing emissions with the exception of components listed in Attachment 1 to these conditions titled Pressure Relief Valves Exempt from Abatement.

5.

This permit authorizes pilot emissions from the CRU No. 4 Flare System, CRU No. 4 Flare System, Delayed Coking Unit 1 Flare System, Delayed Coking Unit 1 Flare System, FCCU No. 3 Flare Stack, HCU No. 1 Flare Stack, HTU No. 4 Flare Stack, VPS No. 4 Flare Stack, VPS No. 2 Flare Stack, ARU No. 1 Flare Stack, ARU No. 2 Flare Stack, ALKY 4 Flare Stack, HTU No. 1 Flare Stack, HTU No. 2 Flare Stack, and HTU No. 3 Flare Stack. 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.

6. All combustion sources covered under this permit shall be fired with either sweet natural gas as defined in Title 30 Texas Administrative Code grain total sulfur expressed as hydrogen sulfide (H_2S) per dry standard cubic feet (dscf) (equivalent to 160 ppmv) on a rolling three-hour basis and no more than 120 ppmv on a rolling 24-hour basis. Additionally, the combustion sources fired with refinery fuel gas shall comply with the requirements of 40 CFR 60.104(a)(1), 60.105(a)(4), 60.106(e)(1), and 60.107(e).

7. There shall be no visible emissions from the following facilities, except for those periods described in 30 TAC § 111.111(a):

- Heaters; and
- Sulfur recovery unit (SRU) incinerators

8. The NOx emissions from heaters listed below by Emission Point No. (EPN) and Facility Identification No. (FIN) shall not exceed the following:

EPN	FIN	Name/Description	(A)	(B)
SVPS2-1	VPS2ATM1HT, VPS2ATM2HT, VPS2ATM3HT, VPS2VAC1HT, and VPS2VAC2HT	VPS No. 2 Heaters – Combined Stack	287.5	0.04

A. Maximum combined 12 month rolling average firing rate for heaters, MMBtu/hr

B. Combined NO_x emissions for heaters, lb/MMBtu – 12 month rolling average

Compliance with these limits shall be determined by CEMS.

9. [reserved]

10. Process wastewater drains shall be equipped with water seals or equivalent; lift stations, manholes, junction boxes, and all other wastewater collection system components upstream of the API separator shall be equipped with either closed vent systems that route all organic vapor to control devices, or controls to prevent emission of the organic vapors to the atmosphere.

Water seals shall be checked by visual or physical inspection monthly for indications of low water levels or other conditions that would reduce the effectiveness of water seal controls. Water seals shall be restored as necessary. Records of these inspections and any corrective actions taken shall be maintained for a period of five years and made available to representatives of the Texas Commission on Environmental Quality upon request.

Piping, Valves, Connectors, Pumps, And Compressors In VOC Service-28VHP

11. The 28 VHP fugitive monitoring program shall be in effect for fugitives associated with the following units until the introduction of feed to a new major Crude Expansion Project (CEP) unit (DCU2, HCU2, NPC, or VPS5): Fluid Catalytic Cracking Unit (FCCU3), Catalytic Hydrodesulfurization Unit No. 1 (FCDHDS1), Loading Rack No. 4 (FU-Rack4), Methyl Pyrrolidone Unit 3 (FMPU3), Methyl Pyrrolidone Unit 4 (FMPU4), Vacuum Pipe Still 2 (VPS2), Tail Gas Treating Unit No. 1 (FTGTU1), Tail Gas Treating Unit No. 2 (FTGTU2), Sour Water System (FSWS1), Amine Recovery Unit 1 (FARU1), Amine Recovery Unit 2 (FARU2), Amine Recovery Unit 3 (FARU3), and Amine Recovery Unit 4 (FARU4).

    Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

    A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68°F or (2) to piping and valves two inches nominal size and smaller or (3) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

    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.

    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. Non-accessible valves, as defined by 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

    E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments 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.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

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. For valves equipped with rupture discs, 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.

An approved gas analyzer shall conform to requirements listed in 40 CFR § 60.485(a)-(b).

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 and compressor 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 and compressor 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.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, 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. At the discretion of the TCEQ Executive Director or designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

J. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

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.

<u>Piping, Valves, Connectors, Pumps, And Compressors In VOC Service-28MID</u>

12. The 28 MID fugitive monitoring program shall continue to be in effect for piping fugitive components associated with the units identified in Attachment 2 as "Pre and Post-Feed to CEP." Upon introduction of feed to a new major CEP unit (DCU2, HCU2, NPC, or VPS5), the 28 MID fugitive monitoring program shall continue to be in effect for those units and will then also be in effect for piping fugitive components associated with the units identified in Attachment 2 as "Additional Units Post-Feed to CEP." Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 psia at 68° F, or (2) operating pressure is at least 5 kilopascals (0.725 pound per square inch [psi]) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable ANSI, API, ASME, or equivalent codes.

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

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. Non-accessible valves, as defined by 30 TAC Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically-tested at no less than normal operating pressure and adjustments 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.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer with a directed maintenance program. 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. For valves equipped with rupture discs, 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.

An approved gas analyzer shall conform to requirements listed in 40 CFR § 60.485(a) - (b).

A directed maintenance program shall consist of the repair and maintenance of components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. All new and replacement pumps and compressors shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and 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.

All other pump and compressor seals emitting VOC shall be monitored with an approved gas analyzer at least quarterly.

H. Damaged or leaking valves, connectors, compressor seals, and pump seals 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. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components that cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

I. In lieu of the monitoring frequency specified in paragraph F, valves in gas and light liquid service may be monitored on a semiannual basis if the percent of valves leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Valves in gas and light liquid service may be monitored on an annual basis if the percent of valves leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of valves leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

J. The percent of valves leaking used in paragraph I shall be determined using the following formula:

$$(Vl + Vs) \times 100/Vt = Vp$$

Where:

Vl	=	the number of valves found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.
Vs	=	the number of valves for which repair has been delayed and are listed on the facility shutdown log.
Vt	=	the total number of valves in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor valves.
Vp	=	the percentage of leaking valves for the monitoring period.

K. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable NSPS, or an applicable NESHAPS, and does not constitute approval of alternative standards for these regulations.

<u>Quarterly Connector Monitoring – 28CNTQ</u>

13. Upon introduction of feed to a new major CEP unit (DCU2, HCU2, NPC, or VPS5), the following shall apply to all applicable units identified in Attachment 2:

    A. In addition to the weekly physical inspection required by Item E of the 28MID condition, all accessible connectors in gas or vapor and light and heavy liquid service shall be monitored quarterly with an approved gas analyzer in accordance with Items F thru J of the 28MID condition.

    B. In lieu of the monitoring frequency specified in paragraph A, connectors may be monitored on a semiannual basis if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Connectors may be monitored on an annual basis if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

C. The percent of connectors leaking used in paragraph B shall be determined using the following formula:

$$(Cl + Cs) \times 100/Ct = Cp$$

Where:

Cl = the number of connectors found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

Cs = the number of connectors for which repair has been delayed and are listed on the facility shutdown log.

Ct = the total number of connectors in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including nonaccessible and unsafe-to-monitor connectors.

Cp = the percentage of leaking connectors for the monitoring period.

14. Upon introduction of feed to a new major CEP unit (DCU2, HCU2, NPC, or VPS5), process drains in all applicable units identified in Attachment 2 shall be monitored quarterly at a leak definition of 500 ppmv and replaced or repaired in accordance with Items F and H of the 28MID condition. Process drains shall be designed such that repairs to leaking drains can be performed.

15. Upon introduction of feed to a new major CEP unit (DCU2, HCU2, NPC, or VPS5), valves in heavy liquid service in all applicable units identified in Attachment 2 shall be monitored quarterly at a leak definition of 500 ppmv and replaced or repaired in accordance with Items F and H of the 28MID condition.

16. [reserved]

17. [reserved]

Sulfur Recovery Units (SRUs)

18. During normal operations and planned maintenance, tail gas from the SRUs must be routed to a tail gas treating unit (TGTU). Under no circumstances shall SRU tail gas be flared or released to the atmosphere during normal operations and planned maintenance.

19. All acid gas or other waste gases from facilities associated with the SRUs must be burned in the incinerator and/or flare (emergency use). It is not permissible under any conditions to vent waste gases directly to the atmosphere.

20. The SRU Incinerator Vents (EPNs STGTU1-1 and STGTU2-1) shall be operated with not less than 1 percent oxygen (O_2) in the incinerator stack and not less than 1200°F incinerator firebox temperature. The incinerator firebox exit temperature and incinerator stack O_2 level shall be continuously monitored and recorded. This condition does not apply during stack testing on the incinerators in accordance with the Initial and Periodic Determination of Compliance sections of these conditions in order to determine incinerator performance at alternative operating conditions.

21. The minimum sulfur recovery efficiency for the SRUs shall be 99.8 percent. The sulfur recovery efficiency shall be determined by calculation as follows:

$$\text{Efficiency} = \frac{(\text{S recovered})*(100)}{(\text{S acid gas})}$$

where:

Efficiency	=	sulfur recovery efficiency, percent
S recovered	=	S produced, Long tons per day (LTPD)
S acid gas	=	(S recovered plus S stack), LTPD
S stack	=	sulfur in the incinerator stack, LTPD

The average sulfur emission reduction efficiency (sulfur recovery efficiency) shall be demonstrated for each calendar day by a mass balance calculation using data obtained from the incinerator stack SO_2 monitor, sulfur production records, and other process data. Sulfur recovery efficiency shall be calculated for each day (not a monthly average), but the calculations may be performed monthly. Records of the sulfur recovery efficiency compliance calculations shall be maintained at the plant site for a period of five years and made available to representatives of the TCEQ upon request.

22. The SO_2 concentration in SRU incinerator vents (EPNs STGTU1-1 and STGTU2-1) shall not exceed 250 ppmv averaged over a 12-hour period. Records of the SO_2 in the

incinerators' exhaust gas shall be maintained for five years and made available to representatives of the TCEQ upon request.

23. Sour gas emissions from the sulfur pits, sulfur storage, and sulfur loading operations shall be collected by a vapor collection system and routed back to a SRU thermal reactor, to a TGTU, or to a tail gas incinerator (TGI). During shutdown for maintenance, any emissions from the sulfur pits, sulfur storage, and sulfur truck-loading operations will be routed to an absorption media. Records of SRU downtime shall be maintained for a period of five years and made available to representatives of the TCEQ upon request.

24. Each Amine Recovery Unit (ARU) shall use monoethanol amine, methyl diethanol amine, or diglycol amine. Changing to another H_2S contact solvent for normal operation will require a permit amendment and approval from the Executive Director of the TCEQ.

25. The Rich Amine Charge Tanks in the ARUs shall be checked for hydrocarbons once per day from connections at the 15-foot and 10-foot levels and shall be hand gauged once per week. At least 13 feet of amine shall be held in the charge tanks at any given time.

    A. If hydrocarbons are discovered at or above the 15-foot level, steps shall be taken to ensure that the amine level remains at least at the minimum 13-foot level. Hydrocarbon checks from connections at the 15-foot and 10-foot levels shall be conducted once per shift, and hand gauging shall be conducted on a daily basis until the amine level is restored to at least 13 feet. After the amine being held in the tank has returned to at least 13 feet, hydrocarbon checking/hand gauging can return to the daily/weekly basis. Records of all hydrocarbon checks and hand gauges shall be maintained on-site for a period of five years and made available to representatives of the TCEQ upon request.

26. The rich amine surge system shall have a minimum retention time of 30 minutes based on a minimum of 50 percent capacity of the tanks and the maximum rich amine flow to the tanks. Records of rich amine surge system retention time shall be maintained at the plant site for a period of five years and made available to representatives of the TCEQ upon request.

27. Sour Water Stripper (SWS) Charge Tank levels and checks for hydrocarbons shall be as follows:

    A. During periods other than those described in paragraph B. below, the following shall apply:

        (1) Hydrocarbon checks shall be made once per day from connections at the 15-foot and 10-foot levels, and tanks shall be hand gauged once per week.

(2) At least 13 feet of sour water shall be held in the charge tanks at any given time. If hydrocarbons are discovered at or above the 15-foot level, steps shall be taken to ensure that the sour water level remains at least at the minimum 13-foot level. Hydrocarbon checks from connections at the 15-foot and 10-foot levels shall be conducted once per shift, and hand gauging shall be conducted on a daily basis until the sour water level is restored to at least 13 feet. After the sour water being held in the tank has returned to at least 13 feet, hydrocarbon checking/hand gauging can return to the daily/weekly basis.

B. In order to increase sour water storage capacity preceding a planned shutdown of the SWS, for a period not to exceed 20 days the following shall apply in lieu of the requirements in paragraph A above:

(1) Any accumulation of hydrocarbons shall be skimmed from the water surface on all sour water storage tanks prior to drawing inventory down.

(2) The water surface of each sour water charge tank shall be sampled for hydrocarbon accumulation every 4 hours.

(3) At least 12 feet of sour water shall be held in the sour water charge tanks at any given time. If hydrocarbons are discovered at or above the 15-foot level, steps shall be taken to ensure that the sour water level remains at least at the minimum 12-foot level. In the event that tank levels fall below 15 feet, manual tank gauging using gauge tape with "colorcut" applied shall be performed to ensure that the sour water level remains at least at the minimum 12-foot level.

(4) Hydrocarbon checks from connections at the 15-foot and 10-foot levels shall be conducted every 4 hours. If any hydrocarbon is detected at the 10 foot level, charge to the SWS from that tank shall immediately be stopped until steps are taken to ensure that the sour water level remains at least at the minimum 12-foot level.

C. Records of all hydrocarbon checks, hand gauges, beginning and ending dates of drawdown periods, and beginning dates of planned SWS shutdowns shall be maintained on-site for a period of five years and made available to representatives of the TCEQ upon request.

28. Except during periods described in Special Condition No. 27B, the sour water stripper surge system shall have a minimum retention time of three days based on a minimum of 50 percent capacity of the tanks and the maximum sour water flow to the tanks. Records of sour water stripper surge system retention time shall be maintained at the plant site for a period of five years and made available to representatives of the TCEQ upon request.

29. The vapors from the sour water charge tanks (surge tanks) and flash tanks shall be vented to the plant vapor recovery system.

30. There shall be a minimum of 12 H_2S monitors placed throughout the SRU2 and SRU3, Amine Regeneration Unit (ARU1 and ARU2), and Sour Water Stripper (SWS1) areas. There shall be a minimum of 8 H_2S monitors placed throughout the SRU4, ARU4, and TGTU2 areas. These monitors shall be arranged in such a way that provides coverage for wind directions varying through 360 degrees. The monitors shall be set to alarm at a concentration of 10 ppm and shall alarm in the control room and in the local plant area. A diagram of the operating units and the location of the monitors shall be provided at the plant site and made available to representatives upon request. Records of alarms shall be maintained for a period of five years and made available to representatives of the TCEQ upon request.

Cooling Towers

31. This condition applies to the following cooling towers existing prior to the CEP:

FIN	EPN	Location
FLCDU	FK33PH	Lube Catalytic Dewaxing Unit
VPS 2 FE	FKVPS2	Vacuum Pipestill 2
VPS NO4 FE	FKVPS4	Vacuum Pipestill 4
CRU 4 FE	FKCRU4	Catalytic Reforming Unit 4
HTU1FE	FKHTU1&2	Hydrotreating Unit 1
HTU2FE	FKHTU1&2	Hydrotreating Unit 2
HTU3FE	FKHTU3	Hydrotreating Unit 3
FHTU4	FK33PH	Hydrotreating Unit 4
FKDCU1	FKDCU1	Delayed Coking Unit 1
FCCU NO3FE	FKFCCU3	Fluid Catalytic Cracking Unit 3

FCCU NO2FE	FKFCCU1&2	Alkylation Unit
MPU3FE	FKMPU3	Methyl Pyrollidone Unit 3
FMPU4	FKMPU4	Methyl Pyrollidone Unit 4
ARU 3 FE	FKARU3	Amine Recovery Unit 3
SRU 4 FE	FKVPS1	Sulfur Recovery Unit 4

A. The cooling tower water shall be monitored monthly for VOC leakage from heat exchangers in accordance with the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition) or another air stripping method approved by the TCEQ Executive Director.

B. Cooling water VOC concentrations above 0.08 ppmw indicate faulty equipment. Equipment shall be maintained so as to minimize VOC emissions into the cooling water. At all cooling towers existing prior to the CEP, faulty equipment shall be repaired at the earliest opportunity, but no later than the next planned shutdown of the process unit in which the leak occurs.

Emissions from the cooling tower are not authorized if the VOC concentration of the water returning to the cooling tower exceeds 0.8 ppmw. The VOC concentrations above 0.8 ppmw are not subject to extensions for delay of repair under this permit condition. The results of the monitoring and maintenance efforts shall be recorded.

C. All records shall be maintained at the plant site for a period of five years and made available to representatives of the TCEQ upon request.

32. [reserved]

33. The permit holder shall conduct an analysis of the heat exchanger systems and associated process equipment served by the Alkylation Unit Cooling Tower (FIN FCCU NO2FE, EPN FKFCCU1&2), and the heat exchanger systems and associated process equipment served by the Catalytic Reforming Unit 4 Cooling Tower (FIN CRU 4 FE, EPN FKCRU4). The analysis shall identify and assess the available options for reducing the frequency and magnitude of leaks of process fluid into these cooling water systems. The analysis shall address all options that are economically reasonable and technically practicable. Within 12 months after the renewal of this permit, the holder shall submit a report to the Air Permits Division setting forth its analysis and making its recommendations regarding implementation of identified options. In consultation with the permit holder, the Air Permits Division will determine if any of the options identified

in the report should be implemented, and will notify the permit holder accordingly in writing. Within six months after its receipt of any such notice, the permit holder shall submit an amendment application or alteration request, as appropriate, to implement the option(s) identified in the notice. **(COMPLETE)**

34. This condition applies to FKHTU-5 (Hydrotreater Unit No. 5 Cooling Tower).

    A. The VOC associated with cooling tower water shall be monitored monthly with an air stripping system meeting the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition) or an approved equivalent sampling method. The results of the monitoring, cooling water flow rate and maintenance activities on the cooling water system shall be recorded. The monitoring results and cooling water hourly mass flow rate shall be used to determine cooling tower hourly VOC emissions. The rolling 12-month cooling water emission rate shall be recorded on a monthly basis and be determined by summing the VOC emissions between VOC monitoring periods over the rolling 12-month period. The emissions between VOC monitoring periods shall be obtained by multiplying the total cooling water mass flow between cooling water monitoring periods by the higher of the two VOC monitored results. If the rolling 12-month VOC emissions exceeds the individual annual emission limit for FKHTU-5 - Hydrotreater Unit No. 5 Cooling Tower, a report shall be submitted to the appropriate TCEQ Regional Office within 30 days containing details as to the reasons for the exceedance.

    B. The heat exchange and cooling tower systems shall be maintained so as to minimize VOC emissions into the cooling waters. Faulty equipment shall be repaired at the earliest opportunity; however, leaking equipment shall be repaired no later than 45 days after a VOC concentration equal to or greater than 0.04 ppmw is discovered during the monthly monitoring.

    C. Emissions from the cooling tower are not authorized if the VOC concentration of the water returning to the cooling tower exceeds 0.8 ppmw. The VOC concentrations above 0.8 ppmw are not subject to extensions for delay of repair under this permit condition. The results of the monitoring and maintenance efforts shall be recorded. All records shall be maintained at the plant site for a period of five years and made available to representatives of the TCEQ upon request.

35. [reserved]

Piping, Valves, Pumps, and Compressors in H_2S Service

36. In addition to the 28MID condition (if applicable), piping, valves, pumps, and compressors in H_2S service are subject to the following requirements:

    A. Audio, olfactory, and visual checks for H_2S leaks within the operating area shall be made once each shift while the facility is operating.

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

        (1) Stop the leak by taking the equipment out of service or bypass the equipment so that it is no longer in service.

        (2) Isolate the leak.

        (3) Commence repair or replace the leaking component.

        (4) If the leak cannot be repaired within six hours, the holder of this permit shall use a leak collection or containment system to prevent the leak until repair or replacement can be made if immediate repair is not possible.

    Records shall be maintained at the plant site of the time leaks were detected and all repairs and replacements made due to leaks. These records shall be maintained for a period of five years and made available to representatives of the TCEQ upon request.

Piping, Valves, Pumps, and Compressors in SO_2 or NH_3 Service

37. In addition to the 28MID condition (if applicable), piping, valves, pumps, and compressors in SO_2 or NH_3 service are subject to the following requirements:

    A. Audio, olfactory, and visual checks for SO_2 and NH_3 leaks within the SRUs, ARUs, and SWSs.

    B. Immediately, but no later than one hour upon detection of a leak, the holder of this permit shall take one of the following actions:

        (1) Isolate the leak.

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

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

C. The date and time of each inspection shall be recorded 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 maintained at the plant site for a period of five years and made available to the TCEQ Executive Director or his designated representative upon request.

Fluidized Catalytic Cracking Unit (FCCU)

38. The following applies to the FCCU regeneration vent/vent gas stack (EPN SFCCU3-2):

A. The maximum allowable concentration of the following pollutants in the FCCU vent gas stack (EPN SFCCU3-2) are:

Pollutant	Hourly	24-hr Avg.	Annual	Basis
CO	500 ppmv		500 ppmv	(dry, 0% O_2)
SO_2	157 ppmv	50 ppmv*	25 ppmv*	(dry, 0% O_2)
NO_x	109 ppmv	68 ppmv*	42.8 ppmv*	(dry, 0% O_2)
VOC	15 ppmv		15 ppmv	(dry)

[1] – These limits are required by EPA Consent Decree No. H-01-0978. The annual limits apply to rolling 365 day periods.

B. The total particulate matter (PM) emissions from the FCCU Vent Gas Stack (EPN SFCCU3-2) shall not exceed one pound per 1,000 pounds of coke burn-off.

Alkylation Unit

39. All waste gas streams containing sulfuric acid (H_2SO_4) shall be routed to the caustic scrubber to provide 99 percent removal of H_2SO_4 being routed to the flare. Storage tank vents, cooling tower exhaust, and process fugitive emissions are excluded from this requirement. Any other exception to this condition requires prior approval by the TCEQ Executive Director, and such exceptions may be subject to strict monitoring requirements.

40. The vents of the Spent H_2SO_4 Acid Tanks (EPNs TAL35142 and TAL35143) shall be routed through an alkaline eductor to the plant vapor recovery system.

41. Sampling ports and platform(s) shall be incorporated into the design of the outlet of the blowdown vapor stack according to the specifications set forth in the enclosure entitled "Chapter 2, Stack Sampling Facilities." Alternate sampling facility designs may be submitted for approval by the TCEQ Regional Director.

42. The caustic scrubber system solution shall be sampled at the outlet of the scrubber and analyzed for weight percent caustic daily. These records shall be maintained at the plant site for a period of five years and made available to the TCEQ Executive Director or his designated representative upon request. Caustic shall be changed out when the level concentration of caustic is 1 percent or less.

Delayed Coking Units

43. All conveyors shall be covered and water sprays shall be installed and operated as necessary at all coke product transfer points in order to control coke dust emissions to the minimum level possible under existing conditions.

44. Coke stockpiles shall be sprinkled with water and/or chemicals as necessary to control coke dust emissions to the minimum level possible under existing conditions.

45. All truck traffic hauling coke shall be on paved roads from the DCU limits to the plant property line. These roads shall be cleaned upon visible detection of coke particulate emissions.

46. The undercarriage of all coke trucks leaving the plant site shall be washed with water, and the coke load shall be covered with a canvas or similar type of covering firmly secured to reduce particulate emissions.

47. As determined by a trained observer, no visible emissions from coke handling facilities shall leave the plant property.

48. Coke product may be hauled off-site by rail, truck, or conveyor. Rail or conveyor shall be the primary mode of transportation. A water truck in operating condition shall be kept at the plant when coke product is being hauled off-site by truck. The water truck shall be used to control fugitive dust emissions. The TCEQ Regional Office shall be notified when coke loadout operations using trucks commence.

49. The moisture of the coke in the primary coke pad shall be maintained in a visibly wet condition at a level of 8.0 percent or greater. The holder of this permit shall take samples of the coke on the conveyer system transferring coke from the coke pad to the storage silo on each day that transfers are being made and analyze the samples for moisture content and record the results. Compliance with the moisture content requirement shall be

determined based on the weekly average of the moisture content measured for the various days during the calendar week.

50. [reserved]

51. [reserved]

52. [reserved]

Periodic Determination Of Compliance

53. Upon request from the TCEQ Executive Director or in accordance with Special Condition No. 54, the holder of this permit 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 following sources:

Heaters and boilers with firing rates equal to or greater than 40 MMBtu/hr (EPNs SCDHydro/SCHDS2, SDCU1-2, SFCCU3-1, SHCU1-1, SHCU1-2, SHCU1-3, SHCU1-4, SHCU1-5, SHTU2-1, SHTU2-2, SHTU3-1, SHTU3-2, SHTU4-4, SHTU-5, SMPU3-1, SMPU3-2, SMPU4, SMPU4C, SVPS2-1, SVPS2-2, SVPS4-1, SVPS4-4, SVPS4-2, SVPS4-3, SVPS4-5, SVPS4-6, and SVPS4-7);

SRU TGIs (EPNs STGTU1-1 and STGTU2-1); and

FCCU Regenerator (EPN SFCCU3-2).

The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.

A. The appropriate TCEQ Regional Office shall be contacted as soon as testing is scheduled, but not less than 45 days prior to sampling to schedule a pretest meeting.
The notice shall include:

(1) 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.

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 and procedures for submitting the test reports. A written proposed description of any deviation from sampling procedures specified in permit conditions or the TCEQ or the EPA sampling procedures shall be made available to the TCEQ prior to the pretest meeting. The TCEQ Regional Director shall approve or disapprove of any deviation from specified sampling procedures. Requests to waive testing for any pollutant specified in B of this condition shall be submitted to the TCEQ Office of Air, Air Permits Division in Austin. Test waivers and alternate or equivalent procedure proposals for NSPS testing that must have the EPA approval shall be submitted to the TCEQ Regional Director.

B. Air contaminants to be tested for include (but are not limited to) the following for the various units:

(1) Heaters and boilers – NO_x, SO2 and CO.

(2) SRU TGIs - NO_x, CO, SO2, VOC.

(3) FCCU Regenerator – PM (both front and back-half of the sampling train), SO2, and VOC.

C. Each emission point subject to stack emission testing shall be tested within 180 days of receiving a request from the Executive Director. Testing shall be conducted when the facility (or facilities) directly associated with the emission point is operating at maximum emissions potential (e.g., maximum production, throughput, firing rate, etc.) Primary operating parameters that enable determination of maximum emissions potential shall be monitored and recorded during the stack test. These parameters are to be determined at the pretest meeting. If the plant is unable to operate at maximum emissions potential during testing, then future operations may be limited based on the rates established during testing.

D. Copies of the final sampling report shall be forwarded to the TCEQ within 60 days after sampling is completed. Sampling reports shall comply with the attached provisions of Chapter 14 of the TCEQ Sampling Procedures Manual. The reports shall be distributed as follows:

One copy to the appropriate TCEQ Regional Office

54. Attachment 6 to these conditions lists production units with charge/production rates and combustion sources associated with those units. Upon request from the TCEQ Executive Director, or when a unit in that list exceeds its listed charge/production rate by more than

15 percent in any 24-hour period, the holder of this permit shall perform stack sampling and other testing as required, in accordance with Special Condition No. 53, to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the combustion sources listed in Attachment 6.

55. The Reformer Regeneration Vent (EPN SCRU4-2) is subject to the following requirements:

   A. The vent shall be routed through a caustic scrubber prior to discharge to the atmosphere. The scrubber shall be designed to control hydrogen chloride (HCl) emissions to an outlet concentration of 10 ppmv or an overall control efficiency of 99 percent, whichever is less stringent.

   B. The scrubbing solution shall be maintained at or above a pH of 7.0 and analyzed once daily with a pH meter.

   C. The inlet and outlet HCl emissions shall be tested daily with an approved portable analyzer.

   D. Records of the analytical and testing results and the actual testing methods used shall be maintained at the plant site for a period of five years and made available to the TCEQ Executive Director or his designated representative upon request.

Continuous Determination Of Compliance

56. The holder of this permit shall install, calibrate, operate, and maintain CEMSs to measure and record the following:

   A. The NO_x, and O_2 from the No. 4 CRU Heater Stack (EPN SCRU4-1) and the No. 2 Vacuum Pipe Still combined heater stack (EPN VPS2-1);

   B. The SO_2 and O_2 from the SRU/SCOT TGIs (EPNs STGTU1-1 and STGTU2-1),

   C. The NO_x, CO, O_2, and SO_2 from the FCCU Regenerator (EPN SFCCU3-2); and

   D. H_2S in representative locations in the refinery fuel gas system in accordance with the fuel sulfur monitoring requirements of 40 CFR § 60.105.

57. The CEMS shall meet the following requirements:

   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, 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.

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 40 CFR Part 60, Appendix F, § 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.

(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.

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, § 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 once every day, using a minimum of four equally-spaced data points from each one-hour period. The individual average concentrations shall be reduced to units of pounds/hour at least once every week in accordance with Attachment 3 of these conditions, entitled "Calculation of Emission Rates from CEMS Data."

D. All monitoring data and quality assurance data shall be maintained by the source. 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 facility generating emissions 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 facility generating emissions operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgement 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.

58. The holder of this permit shall install, calibrate, operate, and maintain a continuous opacity monitoring system (COMS) to measure and record the opacity from the FCCU Regenerator (EPN SFCCU3-2). An approved alternate monitoring plan for opacity pursuant to 40 CFR Part 60, Subpart J and/or 40 CFR Part 63, Subpart UUU may be used in lieu of a COMS on the FCCU Regenerator. The COMS monitoring system shall meet the following requirements:

A. The COMS shall meet 40 CFR Part 60, Appendix B Performance Specification No 1.

B. The COMS shall meet the requirements of 40 CFR § 60.13. The appropriate TCEQ Regional Manager will be the administrator for alternate monitoring requests, except where the monitoring is also required by an applicable NSPS, 40 CFR Part 60 or NESHAP, 40 CFR Part 61 or 40 CFR Part 63, where EPA Region 6 remains the administrator for alternate monitoring requests. Alternate monitoring requests should be submitted to the appropriate TCEQ Regional Director and EPA Region 6, when they are the administrator, with copies to any local air pollution programs.

C. Monitoring data shall be recorded and maintained as specified in 40 CFR § 60.7(c), (d), (e), and (f).

D. The appropriate TCEQ Regional Office and any local air pollution programs shall be notified at least 30 days prior to any required initial performance evaluation.

E. Quality-assured (or valid) data must be generated when the FCCU 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 FCCU is operated over the previous rolling 12-month period.

Emission Compliance Recordkeeping

59. Records of all compliance testing, CEM results, process parameters (including short-term production rates, firing rates, etc.), and any other data used to demonstrate compliance with emission rate limitations shall be maintained on-site for a period of five years and made available to designated representatives of TCEQ upon request.

Emission calculations to demonstrate compliance with the annual emission rate limitations, which are on a 12-month rolling average basis, shall be performed at least once every calendar quarter. Demonstration of compliance shall be based on the emission calculation methods described below.

A. Tanks:

(1) Routine emissions shall be calculated based on AP-42, Chapter 7 (Fifth Edition), using the physical property data of the material stored and the actual tank configuration. Short-term emission rates shall be based on the maximum expected filling rate for fixed-roof tanks and the higher of the filling rate or withdrawal rate for internal and external floating roof tanks. Rolling 12-month emission rates shall be based on actual rolling 12-month throughput rates.

(2) Emissions from landing and refloating roofs of floating roof tanks for purposes of planned maintenance shall be calculated using API Technical Report 2567, "Evaporative Loss from Storage Tank Floating Roof Landings," dated April 2005. These emissions shall be increased as provided for by Equation No. 5 of the API report, taking into account the number of elapsed days after the tank roof is landed and until all sources of VOC vapor generation (including pools, puddles, leaking pontoons, etc.) are removed prior to refloating the roof.

B. Loading emissions shall be calculated as described in the permit condition entitled VOC Loading Operations, using the physical property data of the material loaded, rolling 12-month throughput for annual emissions, and loading rates for short-term emissions.

C. Fugitives - Emissions shall be calculated based on component counts and corresponding emission factors consistent with TCEQ guidance as of November 15, 2006, including reduction credits consistent with the implementation of the 28VHP, 28MID, and AVO maintenance programs.

D. Boilers/Heaters – Emissions shall be calculated based on CEM information, if required for the source. If CEM information is not available, emissions shall be calculated based on the most recent stack sampling results, if available. If no stack sampling data is available, emissions shall be calculated using the appropriate emission factor for the specific source and the measured daily heating value and average flow rate of the fuel gas.

E. SRU/FCCU – Emissions shall be calculated based on CEM information, if required for the source. If CEM information is not available, emissions shall be calculated based on the most recent stack sampling results for those compounds, if available. If no stack sampling results are available, use the appropriate emission factor for the specific source. The holder of this permit shall record once-per-day the average coke burn-off rate and hours of operation of the FCCU catalyst regenerator.

F. Cooling Towers – Emissions shall be calculated based on actual sampling results and average quarterly recirculation rates.

G. Coke Handling Operations – Emissions shall be calculated based on AP-42, Chapter 13.2.4.2 (Fifth Edition), using monthly throughput rates.

Compliance Assurance Monitoring

60. Compliance Assurance Monitoring requirements will be met as outlined in Attachment 5 to these conditions.

Federal Applicability

61. These facilities shall comply with all applicable requirements of EPA regulations on Standards of Performance for New Stationary Sources in40 CFR Part 60, Subparts A, Db, J, K, Ka, Kb, GG, VV, GGG, and QQQ. **(05/2011)**

62. These facilities shall comply with all applicable requirements of the EPA regulations on NESHAPS in 40 CFR Part 61, Subparts A, M, and FF.

63. These facilities shall comply with all applicable requirements of the EPA regulations on NESHAPS for Source Categories in 40 CFR Part 63, Subparts A, CC, UUU, YYYY, DDDDD, and GGGGG.

64. The limits or requirements identified below apply to the operations of the specified facilities during startup and shutdown. Emissions shall be estimated using good

engineering practice and methods to provide reasonably accurate representations for emissions.

The FCCU as identified as EPN SFCCU3-2:

A. shall not exceed 500 ppmvd CO at zero percent excess air on an hourly basis for more than ten days;

B. shall not exceed 300 ppmv SO_2 on an hourly basis for more than three days;

C. shall not exceed 25 ppmvd SO_2 at zero percent excess air on a 365-day rolling average basis for more than three days;

D. shall not exceed 50 ppmvd SO_2 at zero percent excess air on a 24-hour rolling average basis for more than three days;

E. shall not exceed 408 ppmv NO_x on an hourly average basis prior to July 1, 2009 for more than three days;

F. shall not exceed 200 ppmv NO_x on a rolling 12-month average prior to July 1, 2009 for more than three days;

G. shall not exceed 200 ppmv NOx on a hourly average basis for more than three days;

H. shall not exceed 68 ppmvd NO_x at zero percent excess air on a 24-hour average basis for more than three days;

I. shall not exceed 42.8 ppmvd NO_x at zero percent excess air on a 365-day rolling average basis for more than three days;

J. shall not exceed 7 ppmv NH_3 on a hourly average basis for more than three days; and

K. shall not exceed 1 lb PM/1000 lb coke burned for more than fourteen days.

Dated August 21, 2012

ATTACHMENT 1
Permit 8404
PRESSURE RELIEF VALVES EXEMPT FROM ABATEMENT

UNIT	PRV NO.
VPS2	3027, 3246, 00263, 02722, 02723, 02724, 02725, 02754, 03065, 4786, 491, 6924, 09709, 09710, 09711, 09712, and 09713
VPS4	11222, 11223, 11224, 11225, 01244, 01245, 01246, 01247, 01248, and 01249
No. 27PH	12911
No. 4LR	6656
ALKY	6710, 6711, 6712, 7300, and 7301
UTILITIES	5383
CRU4	03828, 03829, 11801, and11802
FCCU3	8269, 7998, 12339, 12342, 12344, 00609, 00636, 01870, 0287, 04269, 04270, 04272, 8121, 8123, 08087, 08115, 08119, 08150, 08184, 08185, 08186, 08729, 12034, 8277, 8271, 11837, 8116, 3192, 3193, 4271, 08001, 08003, 08004, 08005, 08008, and 08025
HTU2	5861 and 5862
MPU3	12001, 12002, 12009, 12010, 12025, 12023, 12024, 12005, 12006, 12003, 12004, 12030, 12007, 12008, 4817, 11694, 4180, 4182, and 4183
MPU4	12424, 12425, 12422, 12423, 4290, 4291, 754, 756, 12409, 12417, 12418, 12420, 12421, 3237, 4808, 6467, 5784, 5785, 11831, 12412, 12413, and 12427

Dated August 21, 2012

ATTACHMENT 2
28MID LDAR PROGRAM
Permit 8404

28MID LDAR PROGRAM	
Pre and Post – Feed to CEP	**Additional Units Post-Feed to CEP**
Alkylation Unit (FALKY4)	*Fluid Catalytic Cracking Unit (FCCU3)
Amine Recovery Unit 1 (FARU1)	*Catalytic Hydrodesulfurization Unit No. 1 (FCDHDS1)
Amine Recovery Unit 2 (FARU2)	*Loading Rack No. 4 (FU-Rack4)
Amine Recovery Unit 3 (FARU3)	*Methyl Pyrrolidone Unit 3 (FMPU3)
Amine Recovery Unit 4 (FARU4)	*Methyl Pyrrolidone Unit 4 (FMPU4)
Activated Sludge Treat Unit No. 2 (FASTU2)	*Vacuum Pipe Still 2 (FVPS2)
BS&W Tank Farm (FBSW)	*Tail Gas Treating Unit No. 1 (FTGTU1)
Catalytic Reforming Unit No. 4 (FCRU4)	*Tail Gas Treating Unit No. 2 (FTGTU2)
Delayed Coking Unit No. 1 (FDCU1)	*Sour Water System 1 (FSWS1)
Catalytic Hydrodesulfurization Unit No. 2 (FCDHDS2)	
Flare Gas Recovery 1 (FGR-1)	
Flare Gas Recovery 2 (FGR-2)	
Hydrocracking Unit (FHCU1)	
Hydrotreating Unit No. 1 (FHTU1)	
Hydrotreating Unit No. 2 (FHTU2)	
Hydrotreating Unit No. 3 (FHTU3)	
Hydrotreating Unit No. 4 (FHTU4)	
Hydrotreating Unit No. 5 (FHTU5)	
Lube Catalytic Dewaxing Unit (FLDCU)	
Light Oil Treating Area (FLOTA)	
North Side API Separator (FNSSEP)	
North Side Gas Plant (FNSGP)	
Pumphouse 27 Tank Farm (FPH27)	

28MID LDAR PROGRAM	
Pumphouse 57 Tank Farm (FPH57)	
Lift Station (FSCTLA)	
Sulfur Recovery Unit 2 (FSRU2)	
Sulfur Recovery Unit 3 (FSRU3)	
Sulfur Recovery Unit 4 (FSRU4)	
Vacuum Pipe Still 4 (FVPS4)	
WAGS Tank Farm (FWAGS)	
West Side Gas Plant (FWSGP)	
Lube Oil Loading Racks (FLR43/44 FE)	

* 28VHP Prior to CEP

Dated August 21, 2012

ATTACHMENT 3
Permit 8404
CALCULATION OF EMISSION RATES FROM CEMS DATA

(1) Heaters and Boilers:

Emission Rate, lb/hr =

ppmd * (Firing Rate, MMBtu/hr)* C_d * F_d *[20.9/(20.9- $O_2\%_d$)]

where: ppmd = pollutant concentration (dry) in ppm from CEMS

Firing Rate (MMBtu/hr) = firing rate determined from the measured fuel gas firing rate (scf/hr) times the fuel gas heating value (MMBtu/scf) from the most recent fuel gas sample

C_d (NO_X) = 1.194×10^{-7} lb/(scfd-ppmd)

C_d (CO) = 0.7268×10^{-7} lb/(scfd-ppmd)

C_d (NH_3) = 0.4413×10^{-7} lb/(scfd-ppmd)

F_d (scfd/MMBtu) = F factor as determined by 40 CFR 60, Appendix A, Method 19 or by reference to a site-specific table of F_d versus fuel gas heating value approved by the Executive Director

$O_2\%_d$ = percent oxygen (dry) from the O_2 CEMS

(2) SRU/SCOT TGIs:

EPNs STGTU1-1 and STGTU2-1
SO_2 (lb/hr) = 62.22 lb/hr * (SO_2 ppmvd/250 ppm) * (Firing Rate/75 MMBtu/hr)

where: SO_2 ppmd = SO_2 concentration (dry, 0% O_2) in ppm from CEMS

Firing Rate = SRU tail gas incinerator firing rate in MMBtu/hr determined from the measured natural gas firing rate (scf/hr) times the natural gas heating value (MMBtu/scf) from the most recent natural gas sample.

(3) FCCU Regenerator:

NO_x (lb/hr) = 265.7 lb/hr * (NO_x ppmvd/200 ppm) * (Coke Burn/71,166 lb/hr)

CO (lb/hr) = 875.7 lb/hr * (CO ppmvd/500 ppm) * (Coke Burn/71,166 lb/hr)

SO_2 (lb/hr) = 340.0 lb/hr * (SO_2 ppmvd/300 ppm) * (Coke Burn/71,166 lb/hr) where: NO_x, CO, and SO_2 ppmvd = the pollutant concentration from the CEMS in ppmv (dry) at 0% O_2

Coke Burn = the daily average coke burn measured for the corresponding day in lb/hr

Upon approval of the TCEQ Executive Director, the permit holder may use alternative methods to calculate emissions in pounds per hour from the CEMS results for the sources listed above.

Dated August 21, 2012

ATTACHMENT 4
Permit 8404
NOT APPLICABLE

ATTACHMENT 5
Permit 8404
COMPLIANCE ASSURANCE MONITORING

FIN	EPN	Unit Name	CAM Basis*	CAM Option
FCCU3REGEN	SFCCU3-2	FCCU No. 3 Regenerator	MACT UUU	Satisfies CAM requirements
TGTUINCINR	STGTU1-1	Tail Gas Treating Unit No. 1 Incinerator	MACT UUU	Satisfies CAM requirements
STGTU2-1	STGTU2-1	Tail Gas Treating Unit No. 2 Incinerator	MACT UUU	Satisfies CAM requirements
CRU4-CCR	SCRU4-2	Regen Vent Scrubber Emission	MACT UUU	Satisfies CAM requirements
CRU NO4 FS	ECRU4	CRU No. 4 Flare System	CAM Guidance	Pilot Flame Observation with Camera
LDCU	ECRU4	CRU No. 4 Flare System	CAM Guidance	Pilot Flame Observation with Camera
EDCU1	EDCU1	Delayed Coking Unit 1 Flare System	CAM Guidance	Pilot Flame Observation with Camera
SBU2	EDCU1	Delayed Coking Unit 1 Flare System	CAM Guidance	Pilot Flame Observation with Camera
FCCU NO3FS	EFCCU3	FCCU No. 3 Flare Stack	CAM Guidance	Pilot Flame Observation with Camera
HCU NO1FS	EHCU	HCU No. 1 Flare Stack	CAM Guidance	Pilot Flame Observation with Camera
EHTU4	EHTU	HTU No. 4 Flare Stack	CAM Guidance	Pilot Flame Observation with Camera
VPS NO4 FS	EVPS4	VPS No. 4 Flare Stack	CAM Guidance	Pilot Flame Observation with Camera
VPS NO2 FS	EVPS4	VPS No. 2 Flare Stack	CAM Guidance	Pilot Flame Observation with Camera
ARU NO1 FS	EARU1&2	ARU No. 1 Flare Stack	CAM Guidance	Pilot Flame Observation with Camera
ARU NO2 FS	EARU1&2	ARU No. 2 Flare Stack	CAM Guidance	Pilot Flame Observation with Camera
ALKY 4 FE	EFCCU1&2	ALKY 4 Flare Stack	CAM Guidance	Pilot Flame Observation with Camera
EHTU1	EHCU	HTU No. 1 Flare Stack	CAM Guidance	Pilot Flame Observation with Camera

FIN	EPN	Unit Name	CAM Basis*	CAM Option
EHTU2	EHCU	HTU No. 2 Flare Stack	CAM Guidance	Pilot Flame Observation with Camera
EHTU3	EHCU	HTU No. 3 Flare Stack	CAM Guidance	Pilot Flame Observation with Camera

* "CAM Guidance" refers to TCEQ Compliance Assurance Monitoring Guidance Document - February 2003 - Draft.

Dated August 21, 2012

ATTACHMENT 6
Permit 8404

Unit Name	Rate *	EPN	Source Name
Catalytic Reforming Unit No. 4 (CRU4)	52,000	SCRU4-1	Combined Heater Stack
Delayed Coking Unit (DCU)	65,000	SDCU1-1	Coker Heater No. 1
		SDCU1-2	Coker Heater No. 2
Fluid Catalytic Cracking Unit No. 3 (FCCU3) and CD-HDS Unit (FCC Naphtha Desulfurization)	90,000	SFCCU3-1	Charge Heater
		SFCCU3-2	CO Boiler
		SCDHydro/ CDHDS2	Charge Heater 1
		SDHydro/ SCHDS2	Charge Heater 2
Hydrocracking Unit (HCU)	25,000	SHCU1-1	No. 1 Reactor Heater
		SHCU1-2	No. 2 Reactor Heater
		SHCU1-3	Preflash Reboilers
		SHCU1-4	Fractionator Reboiler
Hydrotreating Unit No. 1 (HTU1)	20,000	SHTU1-1	Charge Heater
Hydrotreating Unit No. 2 (HTU2)	42,000	SHTU2-1	Charge Heater
		SHTU2-2	Rerun Tower Reboiler
Hydrotreating Unit No. 3 (HTU3)	44,000	SHTU3-1	Charge Heater
		SHTU3-2	Rerun Tower Reboiler

Unit Name	Rate *	EPN	Source Name
Hydrotreating Unit No. 4 (HTU4)	42,000[3]/18,000[2]	SHTU4-1	Charge Heater No. 1
		SHTU4-2	Charge Heater No. 2
		SHTU4-3	Reboiler Heater
		SHTU4-4	Recycle Gas Heater
Hydrotreating Unit No. 5 (HTU5)	45,000	SHTU5	Charge Heater
Lube Catalytic Dewaxing Unit (LCDU)	16,000	SLCDU1-1	Charge Heater
		SLCDU1-2	Reactor Heater
Methyl Pyrolidone Unit No. 3 (MPU3)	29,000/36,000[1]	SMPU3-1	Heater
		SMPU3-2	Heater
Methyl Pyrolidone Unit No. 4 (MPU4)	81,000	SMPU4	R. O. and Secondary Raffinate Heaters
		SMPU4C	Extract Heater
Sulfur Complex (SRUs 2, 3 and 4)	576.2 LTPD	STGTU1-1	TGTU No. 1 Incinerator
		STGTU2-1	TGTU No. 2 Incinerator
		STGTU1-2	Hot Oil Heater
		STGTU2-2	Hot Oil Heater

Unit Name	Rate *	EPN	Source Name
Vacuum Pipe Still No. 2 (VPS2)	80,000	SVPS2-1	Common Heater Stack
		SVPS2-2	Atmospheric Heater No. 4 Stack
Vacuum Pipe Still No. 4 (VPS4)**	200,000	SVPS4-1	Atmospheric C Heater
		SVPS4-2	Atmospheric A Heater
		SVPS4-3	Atmospheric B Heater
		SVPS4-4	Naphtha Reboiler
		SVPS4-5	Vacuum Heater A
		SVPS4-6	Vacuum Heater B
		SVPS4-7	Common Heater Stack

* Charge/production rate, barrels/day

** Stack sampling will be required for either SVPS4-7 (which is the combined stack) or individually for SVPS4-2, SVPS4-3, SVPS4-5, and SVPS4-6. Either sampling scenario is acceptable.

[1] Charge/Solvent Rates

[2] Lube Train Section

[3] Gasoil throughput increased from 26,000 BPSD in amendment approved February 2001

Dated: August 21, 2012

Emission Sources - Maximum Allowable Emission Rates
(Pre CEP)
Permit Numbers 8404

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
FKARU3	ARU No. 3 Cooling Tower (5)	VOC	0.01	0.04
		Benzene	0.01	0.01
		Chlorine	0.01	0.06
FKCRU4	CRU 4 Cooling Tower (5)	VOC	0.04	0.16
		Benzene	0.01	0.01
		Chlorine	0.06	0.27
FKFCCU1&2	Alky Cooling Tower (5)	VOC	1.49	6.53
		Benzene	0.01	0.01
		Chlorine	0.18	0.81
FKFCCU3	FCCU 3 Cooling Tower (5)	VOC	4.41	19.32
		Benzene	0.01	0.01
		Chlorine	0.54	2.38
FK33PH	No. 33PH East Cooling Tower (5)	VOC	0.09	0.41
		Benzene	0.01	0.01
		Chlorine	0.04	0.18
FKDCU1	DCU 1 Cooling Tower (5)	VOC	0.06	0.28
		Benzene	0.01	0.01
		Chlorine	0.11	0.48

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
FK33PH	No. 33PH West Cooling Tower (5)	VOC	0.02	0.10
		Benzene	0.01	0.01
		Chlorine	0.04	0.18
FKMPU4	MPU No. 4 Cooling Tower (5)	VOC	0.07	0.29
		Benzene	0.01	0.01
		Chlorine	0.11	0.50
FKHTU1&2	HTU No. 1 and 2 Cooling Tower (5)	VOC	0.02	0.07
		Benzene	0.01	0.01
		Chlorine	0.02	0.09
FKHTU1&2	HTU No. 1 and 2 Cooling Tower (5)	VOC	0.02	0.07
		Benzene	0.01	0.01
		Chlorine	0.03	0.11
FKHTU3	HTU No. 3 Cooling Tower (5)	VOC	0.01	0.04
		Benzene	0.01	0.01
		Chlorine	0.02	0.07
FKMPU3	MPU No. 3 Cooling Tower (5)	VOC	0.07	0.29
		Benzene	0.01	0.01
		Chlorine	0.11	0.50
FKHTU5	HTU5 Cooling Tower (5)	VOC	0.28	1.23
FKVPS1	VPS No. 1 Cooling Tower (5)	VOC	0.02	0.08
		Benzene	0.01	0.01
		Chlorine	0.03	0.14

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
FKVPS2	VPS No. 2 Cooling Tower (5)	VOC	1.09	4.78
		Benzene	0.01	0.01
		Chlorine	0.13	0.59
FKVPS4	VPS No. 4 Cooling Tower (5)	VOC	1.05	4.60
		Benzene	0.01	0.01
		Chlorine	0.13	0.57
Combustion Sources				
SFCCU3-2	FCCU No. 3 Regenerator	NO_X	149.00	256.09
		VOC	20.63	90.35
		SO_2	299.00	208.28
		CO	415.87	1,821.49
		PM	71.17	311.71
		PM_{10}	71.17	311.71
		$PM_{2.5}$	71.17	311.71
SCRU4-1	Combined Heater Stack	NO_X	47.47	178.23
		VOC	4.27	16.02
		SO_2	29.47	65.84
		CO	65.16	244.63
		PM	5.90	22.13
		PM_{10}	5.90	22.13
		$PM_{2.5}$	5.90	22.13

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
SCDHDS1	CDHDS1 Heater	NO_X	4.38	14.06
		VOC	0.39	1.26
		SO_2	2.72	5.19
		CO	6.00	19.30
		PM	0.54	1.75
		PM_{10}	0.54	1.75
		$PM_{2.5}$	0.54	1.75
SFCCU3-1	FCCU 3 Charge Heater	NO_X	9.91	25.31
		VOC	0.89	2.27
		SO_2	6.15	9.35
		CO	13.60	34.74
		PM	1.23	3.14
		PM_{10}	1.23	3.14
		$PM_{2.5}$	1.23	3.14
SHCU1-1	HCU No. 1 Reactor No.1 Heater	NO_X	4.20	15.77
		VOC	0.28	1.06
		SO_2	1.96	4.37
		CO	4.32	16.23
		PM	0.39	1.47
		PM_{10}	0.39	1.47
		$PM_{2.5}$	0.39	1.47

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SHCU1-2	HCU No. 1 Reactor No.2 Heater	NO_X	5.32	19.97
		VOC	0.36	1.35
		SO_2	2.48	5.53
		CO	5.48	20.56
		PM	0.50	1.86
		PM_{10}	0.50	1.86
		$PM_{2.5}$	0.50	1.86
SHCU1-3	HCU No. 1 Preflash Boiler	NO_X	7.19	26.98
		VOC	0.48	1.82
		SO_2	3.35	7.48
		CO	7.40	27.77
		PM	0.67	2.51
		PM_{10}	0.67	2.51
		$PM_{2.5}$	0.67	2.51
SHCU1-4	HCU No. 1 Fractionator Boiler	NO_X	7.20	31.54
		VOC	0.49	2.13
		SO_2	3.35	8.74
		CO	7.41	32.46
		PM	0.67	2.94
		PM_{10}	0.67	2.94
		$PM_{2.5}$	0.67	2.94

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
SHTU1-1	HTU No. 1 Charge Heater	NO_X	2.45	9.20
		VOC	0.22	0.83
		SO_2	1.52	3.40
		CO	3.36	12.62
		PM	0.30	1.14
		PM_{10}	0.30	1.14
		$PM_{2.5}$	0.30	1.14
SHTU2-1	HTU No. 2 Charge Heater	NO_X	3.78	14.19
		VOC	0.34	1.28
		SO_2	2.35	5.24
		CO	5.19	19.48
		PM	0.47	1.76
		PM_{10}	0.47	1.76
		$PM_{2.5}$	0.47	1.76
SHTU2-2	HTU No. 2 Reboiler	NO_X	2.94	11.04
		VOC	0.26	0.99
		SO_2	1.83	4.08
		CO	4.04	15.15
		PM	0.37	1.37
		PM_{10}	0.37	1.37
		$PM_{2.5}$	0.37	1.37

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
SHTU3-1	HTU No. 3 Charge Heater	NO_X	4.21	15.79
		VOC	0.38	1.42
		SO_2	2.61	5.83
		CO	5.77	21.68
		PM	0.52	1.96
		PM_{10}	0.52	1.96
		$PM_{2.5}$	0.52	1.96
SHTU3-2	HTU No. 3 Reboiler	NO_X	4.23	14.48
		VOC	0.38	1.30
		SO_2	2.62	5.35
		CO	5.80	19.87
		PM	0.53	1.80
		PM_{10}	0.53	1.80
		$PM_{2.5}$	0.53	1.80
SHTU4-1	CHGE Heater 1	NO_X	3.83	9.15
		VOC	0.21	0.49
		SO_2	1.43	2.03
		CO	3.15	7.54
		PM	0.29	0.68
		PM_{10}	0.29	0.68
		$PM_{2.5}$	0.29	0.68

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SHTU4-2	CHGE Heater 2	NO_X	3.83	9.15
		VOC	0.21	0.49
		SO_2	1.43	2.03
		CO	3.15	7.54
		PM	0.29	0.68
		PM_{10}	0.29	0.68
		$PM_{2.5}$	0.29	0.68
SHTU4-3	Reboiler Heater	NO_X	2.33	6.66
		VOC	0.16	0.45
		SO_2	1.09	1.84
		CO	2.40	6.85
		PM	0.22	0.62
		PM_{10}	0.22	0.62
		$PM_{2.5}$	0.22	0.62
SHTU4-4	Recycle Gas Heater	NO_X	8.22	28.17
		VOC	0.55	1.90
		SO_2	3.83	7.81
		CO	8.46	29.00
		PM	0.77	2.62
		PM_{10}	0.77	2.62
		$PM_{2.5}$	0.77	2.62

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
SHTU5	HTU5 Heater	NO_X	2.46	9.22
		VOC	0.38	1.42
		SO_2	2.61	5.84
		CO	2.56	9.62
		PM	0.52	1.96
		PM_{10}	0.52	1.96
		$PM_{2.5}$	0.52	1.96
SLCDU1-1	LCDU Charge Heater	NO_X	2.12	7.28
		VOC	0.19	0.65
		SO_2	1.32	2.69
		CO	2.91	9.99
		PM	0.26	0.90
		PM_{10}	0.26	0.90
		$PM_{2.5}$	0.26	0.90
SLCDU1-2	LCDU Charge Heater	NO_X	2.59	9.72
		VOC	0.23	0.87
		SO_2	1.61	3.59
		CO	3.55	13.35
		PM	0.32	1.21
		PM_{10}	0.32	1.21
		$PM_{2.5}$	0.32	1.21

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
SMPU3-1	MPU Refined Oil Mix Heater	NO_X	3.31	12.61
		VOC	0.22	0.85
		SO_2	1.54	3.49
		CO	3.41	12.99
		PM	0.31	1.17
		PM_{10}	0.31	1.17
		$PM_{2.5}$	0.31	1.17
SMPU3-2	MPU No. 3 Extract Heater	NO_X	8.94	34.02
		VOC	0.60	2.29
		SO_2	4.16	9.43
		CO	9.20	35.02
		PM	0.83	3.17
		PM_{10}	0.83	3.17
		$PM_{2.5}$	0.83	3.17
SMPU4	MPU 4 Secondary Heater Stack	NO_X	0.72	3.15
		VOC	0.05	0.21
		SO_2	0.34	0.87
		CO	0.74	3.25
		PM	0.07	0.29
		PM_{10}	0.07	0.29
		$PM_{2.5}$	0.07	0.29

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
SMPU4	MPU 4 Secondary Heater Stack	NO_X	3.52	13.42
		VOC	0.24	0.90
		SO_2	1.64	3.72
		CO	3.62	13.82
		PM	0.33	1.25
		PM_{10}	0.33	1.25
		$PM_{2.5}$	0.33	1.25
SMPU4C	MPU No 4 Extract Heater	NO_X	9.07	39.74
		VOC	0.61	2.68
		SO_2	4.22	11.01
		CO	9.34	40.90
		PM	0.84	3.70
		PM_{10}	0.84	3.70
		$PM_{2.5}$	0.84	3.70
SCDHydro/SCHDS2	CDHydro/CDHDS2 Heater	NO_X	3.67	13.05
		VOC	0.50	1.76
		SO_2	3.42	7.23
		CO	7.56	26.87
		PM	0.68	2.43
		PM_{10}	0.68	2.43
		$PM_{2.5}$	0.68	2.43

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
SHCU1-5	HCU No. 1 Prefractionator Heater	NO_X	0.93	3.50
		VOC	0.25	0.94
		SO_2	1.74	3.88
		CO	3.84	14.43
		PM	0.35	1.31
		PM_{10}	0.35	1.31
		$PM_{2.5}$	0.35	1.31
SDCU1-1	Coker Heater No.1	NO_X	17.56	65.42
		VOC	1.18	4.41
		SO_2	8.17	18.12
		CO	18.07	67.34
		PM	1.64	6.09
		PM_{10}	1.64	6.09
		$PM_{2.5}$	1.64	6.09
SDCU1-2	Coker Heater No.2	NO_X	17.56	65.42
		VOC	1.18	4.41
		SO_2	8.17	18.12
		CO	18.07	67.34
		PM	1.64	6.09
		PM_{10}	1.64	6.09
		$PM_{2.5}$	1.64	6.09

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
STGTU1-2	Hot Oil Heater	NO_X	0.61	1.21
		VOC	0.03	0.07
		SO_2	0.23	0.27
		CO	0.50	1.00
		PM	0.05	0.09
		PM_{10}	0.05	0.09
		$PM_{2.5}$	0.05	0.09
STGTU2-2	Hot Oil Heater	NO_X	3.64	13.67
		VOC	0.20	0.74
		SO_2	1.36	3.03
		CO	3.00	11.25
		PM	0.27	1.02
		PM_{10}	0.27	1.02
		$PM_{2.5}$	0.27	1.02
SHTU3-3	HTU No.3 Hydrogen Heater	NO_X	0.70	2.63
		VOC	0.13	0.47
		SO_2	0.87	1.94
		CO	1.92	7.21
		PM	0.17	0.65
		PM_{10}	0.17	0.65
		$PM_{2.5}$	0.17	0.65

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SVPS2-1	VPS No.2 Common Heater Stack	NO_X	13.52	50.37
		VOC	1.82	6.79
		SO_2	12.59	27.91
		CO	27.84	103.70
		PM	2.52	9.38
		PM_{10}	2.52	9.38
		$PM_{2.5}$	2.52	9.38
SVPS2-2	VPS No. 2, No. 4 Atmospheric Heater	NO_X	2.80	10.51
		VOC	0.38	1.42
		SO_2	2.61	5.82
		CO	5.76	21.64
		PM	0.52	1.96
		PM_{10}	0.52	1.96
		$PM_{2.5}$	0.52	1.96
SVPS4-1	VPS No. 4, No. 3 Atmospheric Heater	NO_X	8.40	36.79
		VOC	0.75	3.31
		SO_2	5.22	13.59
		CO	11.53	50.50
		PM	1.04	4.57
		PM_{10}	1.04	4.57
		$PM_{2.5}$	1.04	4.57

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
SVPS4-4	VPS No. 4 Naphtha Splitter Reboiler	NO_X	3.48	15.24
		VOC	0.31	1.37
		SO_2	2.16	5.63
		CO	4.78	20.92
		PM	0.43	1.89
		PM_{10}	0.43	1.89
		$PM_{2.5}$	0.43	1.89
SVPS4-2	Atmospheric Heater No. 1 (8)	NO_X	10.50	
		VOC	0.94	
		SO_2	6.52	
		CO	14.41	
		PM	1.30	
		PM_{10}	1.30	
		$PM_{2.5}$	1.30	
SVPS4-3	Atmospheric Heater No. 2 (8)	NO_X	10.50	
		VOC	0.94	
		SO_2	6.52	
		CO	14.41	
		PM	1.30	
		PM_{10}	1.30	
		$PM_{2.5}$	1.30	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SVPS4-5	Vacuum Heater No. 1	NO_X	8.70	
		VOC	0.78	
		SO_2	5.40	
		CO	11.94	
		PM	1.08	
		PM_{10}	1.08	
		$PM_{2.5}$	1.08	
SVPS4-6	Vacuum Heater No. 2	NO_X	8.70	
		VOC	0.78	
		SO_2	5.40	
		CO	11.94	
		PM	1.08	
		PM_{10}	1.08	
		$PM_{2.5}$	1.08	
SVPS4-7	Combined Heater Stack (8) (9)	NO_X	39.36	165.80
		VOC	3.54	15.49
		SO_2	24.44	63.68
		CO	54.02	236.62
		PM	4.89	21.41
		PM_{10}	4.89	21.41
		$PM_{2.5}$	4.89	21.41

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
STGTU1-1	Tail Gas Treating Unit No. 1 Incinerator	NO_X	6.00	18.22
		VOC	0.40	1.23
		SO_2	62.22	236.83
		CO	10.89	41.45
		PM	0.56	1.70
		PM_{10}	0.56	1.70
		$PM_{2.5}$	0.56	1.70
STGTU2-1	Tail Gas Treating Unit No. 2 Incinerator	NO_X	7.50	22.78
		VOC	0.40	1.23
		SO_2	62.22	236.83
		CO	10.89	41.45
		PM	0.56	1.70
		PM_{10}	0.56	1.70
		$PM_{2.5}$	0.56	1.70
Loading Operations				
FLR39	Loading Rack No. 39	VOC	0.44	0.34
Storage Tanks				
TK 1945	Storage Tank No. 1945	VOC	3.88	5.33
TK 2040	Storage Tank No. 2040	VOC	1.82	1.87
TK 2041	Tank 2041	VOC	7.32	6.64
TAL35144	Fresh Caustic	VOC	0.01	0.01
TAL35140	Fresh Sulfuric Acid Tank	H_2SO_4	0.29	0.02

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
TAL35141	Fresh Sulfuric Acid Tank	H2SO4	0.29	0.02
TAR01748	Storage Tank No. 1748	VOC (7)	Vapor	Recovery
TBP32451	Storage Tank No. 32451	VOC (7)	Vapor	Recovery
TBS01740	Storage Tank No. 1740	VOC (7)	Vapor	Recovery
TBS01741	Storage Tank No. 1741	VOC (7)	Vapor	Recovery
TK 1803	Storage Tank No. 1803	VOC (7)	Vapor	Recovery
TK 1804	Storage Tank No. 1804	VOC (7)	Vapor	Recovery
TDC01825	Storage Tank 1825	VOC (7)	Vapor	Recovery
TFT12824	Storage Tank No. 12824	VOC	29.10	0.23
TK 1930	Amine Surge tank	VOC	0.07	0.01
TML01247	Storage Tank No. 1247	VOC	5.08	8.87
TML01248	Storage Tank No. 1248	VOC	6.16	8.48
TML01250	Storage Tank No. 1250	VOC	5.63	7.33
TML01251	Storage Tank No. 1251	VOC	5.63	2.28
TML01252	Storage Tank No. 1252	VOC	6.17	7.03
TML01254	Storage Tank No. 1254	VOC	5.89	7.06
TML01490	Storage Tank No. 1490	VOC	1.33	5.31
TML01524	Storage Tank No. 1524	VOC	4.59	7.22
TML01525	Storage Tank No. 1525	VOC	0.51	1.71
TML01526	Storage Tank No. 1526	VOC	6.95	9.50
TML01663	Storage Tank No. 1663	VOC	6.94	5.27
TML01698	Storage Tank No. 1698	VOC	4.83	13.04
TML01699	Storage Tank No. 1699	VOC	4.82	10.44

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
TML01767	Storage Tank No. 1767	VOC	0.90	4.04
TML01768	Storage Tank No. 1768	VOC	0.89	3.77
TML01904	Storage Tank No. 1904	VOC	5.91	7.73
TML19272	Storage Tank No. 19272	VOC	5.52	5.76
TP108874	Storage Tank No. 8874	VOC	1.02	0.54
TP301697	Storage Tank No. 1697	VOC	2.13	1.55
TST01475	Storage Tank No. 1475	VOC	0.52	2.01
TST01510	Storage Tank No. 1510	VOC	1.36	4.87
TST01511	Storage Tank No. 1511	VOC	1.71	5.16
TST01530	Storage Tank No. 1530	VOC (7)	Vapor	Recovery
TST01553	Storage Tank No. 1553	VOC	1.74	5.21
TST01600	Storage Tank No. 1600	VOC	2.55	2.42
TST01601	Storage Tank No. 1601	VOC	1.67	5.28
TST01617	Storage Tank No. 1617	VOC (7)	Vapor	Recovery
TST01671	Storage Tank No. 1671	VOC	0.81	2.55
TST01679	Storage Tank No. 1679	VOC	4.37	4.37
TST01681	Storage Tank No. 1681	VOC (7)	Vapor	Recovery
TST01712	Storage Tank No. 1712	VOC	1.75	4.04
TST01718	Storage Tank No. 1718	VOC	0.04	0.02
TST01719	Storage Tank No. 1719	VOC	0.04	0.01
TST01775	Storage Tank No.1775	VOC	0.99	4.14
TST01787	Storage Tank No. 1787	VOC	0.51	2.24
TST01850	Storage Tank No. 1850	VOC (7)	Vapor	Recovery

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
TST01884	Storage Tank No. 1884	VOC (7)	Vapor	Recovery
TST01885	Storage Tank No. 1885	VOC	0.80	3.66
TST01886	Storage Tank No. 1886	VOC	3.13	8.7
TST01893	Storage Tank No. 1893	VOC	5.36	6.67
TST01894	Storage Tank No. 1894	VOC	4.55	7.91
TST01895	Storage Tank No. 1895	VOC	1.17	3.58
TST01900	Storage Tank No. 1900	VOC (7)	Vapor	Recovery
TST01913	Storage Tank No. 1913	VOC	0.66	2.61
TST01920	Storage Tank No. 1920	VOC	1.04	3.18
TST19194	Storage Tank No. 19194	VOC	1.09	4.87
TST21657	Storage Tank No. 21657	VOC	4.37	4.29
TST21774	Storage Tank No. 21774	VOC	4.82	5.92
TST21775	Storage Tank No. 21775	VOC	4.82	4.36
TVA01820	Storage Tank 1820	VOC	0.01	0.01
TVA01821	Storage Tank 1821	VOC	0.05	0.04
TST01886	Storage Tank No. 1886	VOC	3.13	8.7
TWT01887	Storage Tank No. 1887	VOC (7)	Vapor	Recovery
TNKGRP2	Tank Group (6)	VOC	175.92	171.38
		Benzene	0.19**	0.30
		H2SO4	0.59	0.03

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
Vents				
SCRU4-2	Regen Vent Scrubber Emissions	NO_X	0.97	4.25
		SO_2	0.67	2.96
		PM	0.06	0.26
		PM_{10}	0.06	0.26
		$PM_{2.5}$	0.06	0.26
		HCl	0.06	0.24
		Chlorine	0.01	0.05
SVVMPU3-3	MPU No. 3 Vacuum System Emissions	VOC	1.50	6.60
Fugitive Emissions				
FHTU5	HTU5 Fugitives (5)	VOC	3.50	15.32
FCOKE1	Delayed Coking Unit Coke Handling Fugitives (5)	PM	0.01	0.01
		PM_{10}	0.01	0.01
		$PM_{2.5}$	0.01	0.01
F10MTR	10 MTR Cell (storm water)	VOC	0.01	0.01
F11MTR	11 MTR Cell (storm water)	VOC	0.01	0.01
F4MTR	4 MTR Cell (storm water)	VOC	0.01	0.01
FALKY4	ALKY 4 (5)	VOC	14.18	62.12
		Benzene	0.01	0.01
FARU1	ARU No. 1 Fugitive Emissions (5)	VOC	0.43	1.87
		Benzene	0.01	0.01
		Hydrogen Sulfide	0.35	1.52

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	**TPY (4)**
FARU2	ARU No. 2 Fugitive Emissions (5)	VOC	0.21	0.9
		Benzene	0.01	0.01
		Hydrogen Sulfide	0.17	0.73
FARU3	ARU No. 3 Fugitive Emissions (5)	VOC	0.30	1.31
		Benzene	0.01	0.01
		Hydrogen Sulfide	0.16	0.68
FARU4	Fugitives ARU 4 (5)	VOC	0.47	2.06
		Benzene	0.01	0.01
		Hydrogen Sulfide	0.08	0.36
FASTU2	WW Collection Oil Recovery (5)	VOC	6.32	27.67
		Benzene	0.01	0.01
FBOTF	BOTF Fugitives (5)	VOC	0.48	1.22
FBSW	Bottoms, Solids, Water Tanks Farm Fugitives (5)	VOC	1.40	6.12
		Benzene	0.01	0.01
FCDHDS1	CDHDS1 Fugitive Emissions (5)	VOC	4.83	21.15
		Benzene	0.06	0.25
FCDHDS2	CDHDS2 Fugitive Emissions (5)	VOC	8.70	38.11
		Benzene	0.1	0.46
FCGHT	CGHT Fugitives (5)	VOC	0.01	0.01
FCRU4	CRU No. 4 Fugitive Emissions (5)	VOC	10.97	48.04
		Benzene	0.03	0.14
FDCU1	DCU 1 Fugitives (5)	VOC	14.63	64.08
		Benzene	0.03	0.13

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
FFCCU3	FCCU No. 3 Fugitive Emission (5)	VOC	27.72	121.41
		Benzene	0.01	0.01
FGR-1	Flare Gas Recovery (5)	VOC	1.68	7.36
		Benzene	0.01	0.01
FGR-2	Flare Gas Recovery (5)	VOC	1.81	7.95
		Benzene	0.01	0.01
FHCU1	HCU No. 1 Fugitive Emissions	VOC	10.19	44.64
		Benzene	0.01	0.01
FHTU1	HTU No. 1 Fugitive Emissions (5)	VOC	3.63	15.91
		Benzene	0.01	0.01
FHTU2	HTU No. 2 Fugitive Emissions (5)	VOC	3.82	16.75
		Benzene	0.01	0.01
FHTU3	HTU No. 3 Fugitive Emissions (5)	VOC	6.30	27.61
		Benzene	0.01	0.01
FHTU4	HTU No. 4 Fugitive Emissions (5)	VOC	10.72	46.97
		Benzene	0.01	0.01
FLCDU	LCDU Fugitive Emissions (5)	VOC	2.38	10.42
		Benzene	0.01	0.01
FLR43/44FE	Loading Rack Fugitives (5)	VOC	0.24	1.07
FMPU3	MPU No. 3 Fugitive Emission (5)	VOC	1.81	7.91
		Benzene	0.01	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
FMPU4	MPU No. 4 Fugitive Emissions (5)	VOC	1.30	5.68
		Benzene	0.01	0.01
FNSGP	North Side Gas Plant Fugitive Emissions (5)	VOC	3.51	15.36
		Benzene	0.01	0.01
FPH27	Pump House No. 27 Fugitive Emissions (5)	VOC	15.27	66.86
		Benzene	0.01	0.01
FPH57	Pump House No. 57 Fugitive Emissions (5)	VOC	4.83	21.13
		Benzene	0.01	0.01
FRES5	Waterwater Reservoir No. 5	VOC	0.01	0.01
FRES10	Wastewater Reservoir No. 10	VOC	0.01	0.01
FSCTLA	Lift Station Fugitives (5)	VOC	0.09	0.38
		Benzene	0.01	0.01
FSRU2	Sulfur Recovery Unit No. 2 Fugitive Emissions (5)	SO_2	0.02	0.07
		Hydrogen Sulfide	0.02	0.07
FSRU3	Sulfur Recovery Unit No. 3 Fugitive Emissions (5)	SO_2	0.02	0.07
		Hydrogen Sulfide	0.02	0.07
FSRU4	Sulfur Recovery Unit No. 4 Fugitive Emissions (5)	SO_2	0.18	0.79
		Hydrogen Sulfide	0.19	0.84
FSWS1	ARU No. 3 Fugitive Emissions (5)	VOC	0.01	0.01
		Hydrogen Sulfide	0.35	1.51
		Ammonia	0.01	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
FTGTU1	Fugitives TGTU #1 (5)	SO_2	0.01	0.03
		CO	0.01	0.06
		Hydrogen Sulfide	0.01	0.06
FTGTU2	Fugitives TGTU #2 (5)	SO_2	0.01	0.03
		CO	0.02	0.07
		Hydrogen Sulfide	0.01	0.06
FUELTKSFE	Fuel Tanks Fugitives (5)	VOC	0.38	1.68
FU-Rack4	Loading Rack No. 4 Fugitives (5)	VOC	0.58	2.52
		Benzene	0.01	0.01
FVPS2	VPS No. 2 Fugitive Emissions (5)	VOC	13.78	60.35
		Benzene	0.03	0.12
FVPS4	VPS No. 4 Fugitive Emissions (5)	VOC	15.92	69.69
		Benzene	0.03	0.14
FWAGS	Wet Acid Gas Scrubber Fugitive Emissions (5)	VOC	1.04	4.56
		Benzene	0.01	0.01
FWSGP	WSGP Fugitives (5)	VOC	0.02	0.09
		Benzene	0.01	0.01
		Hydrogen Sulfide	0.01	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
Flares				
EFCCU3	FCCU No. 3 Flare Stack Pilots	NO_X	0.01	0.03
		CO	0.06	0.24
		SO_2	0.01	0.01
		VOC	0.01	0.01
EHCU	HCU No. 1 Flare Stack Pilots	NO_X	0.01	0.04
		CO	0.07	0.32
		SO_2	0.01	0.01
		VOC	0.01	0.01
EHTU	HTU No. 4 Flare Stack Pilots	NO_X	0.01	0.03
		CO	0.05	0.22
		SO_2	0.01	0.01
		VOC	0.01	0.01
EVPS4	VPS No. 4 Flare Stack Pilots	NO_X	0.01	0.03
		CO	0.06	0.24
		SO_2	0.01	0.01
		VOC	0.01	0.01
ECRU4	CRU No. 4 Flare Stack Pilots	NO_X	0.01	0.03
		CO	0.06	0.24
		SO_2	0.01	0.01
		VOC	0.01	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
EDCU1	Delayed Coking Unit No. 1 Flare Stack Pilots	NO_X	0.01	0.03
		CO	0.05	0.22
		SO_2	0.01	0.01
		VOC	0.01	0.01
EFCCU1&2	ALKY 4 Flare Stack Pilots	NO_X	0.01	0.03
		CO	0.06	0.24
		SO_2	0.01	0.01
		VOC	0.01	0.01
SOURCES TO BE SHUTDOWN				
CHCU	No. 1 HCU Compressor 2750A and 2750B (to be shutdown before CEP) ***	NO_X	36.34	159.18
		VOC	12.12	53.06
		SO_2	0.02	0.12
		CO	36.34	159.18
		PM	0.44	1.90
		PM_{10}	0.44	1.90
		$PM_{2.5}$	0.44	1.90
FLOTA	Light Oil Treating Area Fugitive Emissions (to be shutdown before CEP) (5)	VOC	2.01	8.8
TK 1918	Storage Tank No. 1918 (to be shutdown before CEP)	VOC	2.44	1.62
TST01691	Storage Tank No. 1691 (to be shutdown before CEP)		0.45	3.16
TST01728	(to be shutdown before CEP)	VOC	0.16	0.44

Emission Sources - Maximum Allowable Emission Rates

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
NO_X - total oxides of nitrogen
SO_2 - sulfur dioxide
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
CO - carbon moNOxide
H_2SO_4 - sulfuric acid
HCl - hydrochloric acid
(4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.
(5) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.
(6) Refer to MAERT ATTACHMENT – TANK GROUPfor the specific EPNs, Facility Identification Numbers, and source names included in this group.
(7) These tanks are authorized and routed to vapor recovery.
(8) The burners in the atmospheric heaters (FINS VPS4ATM1HT and VPS4ATM2HT) are authorized by Standard Permit 89842.
(9) The atmospheric and vacuum heaters (FINS VPS4ATM1HT, VPS4ATM2HT, VPS4VAC1HT, and VPS4VAC2HT) may exhaust through this common stack.

* Emission rates are based on and the facilities are limited by the following maximum operating schedule: 8,760 Hrs/yr

** Compliance with hourly emission limits is based on a rolling 12-month period.

*** The FINS included in EPN SCRU4-1 are CRU4INTHT1, CRU4INTHT2, CRU4NHTCHT, CRU4PLATHT, and CRU4SRBL.

*** The FINS included in EPN SVPS2-1 are VPS2ATM1HT, VPS2ATM2HT, VPS2ATM3HT, VPS2VAC1HT, and VPS2VAC2HT.

*** The FINS included in EPN CHCU are CHCU12750A and CHCU12750B.

Date: August 21, 2012

Emission Sources - Maximum Allowable Emission Rates
(Post CEP)
Permit Numbers 8404

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
FKARU3	ARU No. 3 Cooling Tower (5)	VOC	0.01	0.04
		Benzene	0.01	0.01
		Chlorine	0.01	0.06
FKCRU4	CRU 4 Cooling Tower (5)	VOC	0.04	0.16
		Benzene	0.01	0.01
		Chlorine	0.06	0.27
FKFCCU1&2	Alky Cooling Tower (5)	VOC	1.49	6.53
		Benzene	0.01	0.01
		Chlorine	0.18	0.81
FKFCCU3	FCCU 3 Cooling Tower (5)	VOC	4.41	19.32
		Benzene	0.01	0.01
		Chlorine	0.54	2.38
FK33PH	No. 33PH East Cooling Tower (5)	VOC	0.09	0.41
		Benzene	0.01	0.01
		Chlorine	0.04	0.18
FKDCU1	DCU 1 Cooling Tower (5)	VOC	0.06	0.28
		Benzene	0.01	0.01
		Chlorine	0.11	0.48

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
FK33PH	No. 33PH West Cooling Tower (5)	VOC	0.02	0.10
		Benzene	0.01	0.01
		Chlorine	0.04	0.18
FKMPU4	MPU No. 4 Cooling Tower (5)	VOC	0.07	0.29
		Benzene	0.01	0.01
		Chlorine	0.11	0.50
FKHTU1&2	HTU No. 1 and 2 Cooling Tower (5)	VOC	0.02	0.07
		Benzene	0.01	0.01
		Chlorine	0.02	0.09
FKHTU1&2	HTU No. 1 and 2 Cooling Tower (5)	VOC	0.02	0.07
		Benzene	0.01	0.01
		Chlorine	0.03	0.11
FKHTU3	HTU No. 3 Cooling Tower (5)	VOC	0.01	0.04
		Benzene	0.01	0.01
		Chlorine	0.02	0.07
FKMPU3	MPU No. 3 Cooling Tower (5)	VOC	0.07	0.29
		Benzene	0.01	0.01
		Chlorine	0.11	0.50
FKHTU5	HTU5 Cooling Tower (5)	VOC	0.28	1.23
FKVPS1	VPS No. 1 Cooling Tower (5)	VOC	0.02	0.08
		Benzene	0.01	0.01
		Chlorine	0.03	0.14

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
FKVPS2	VPS No. 2 Cooling Tower (5)	VOC	1.09	4.78
		Benzene	0.01	0.01
		Chlorine	0.13	0.59
FKVPS4	VPS No. 4 Cooling Tower (5)	VOC	1.05	4.60
		Benzene	0.01	0.01
		Chlorine	0.13	0.57
Combustion Sources				
SFCCU3-2	FCCU No. 3 Regenerator	NO_X	149.00	256.09
		VOC	20.63	90.35
		SO_2	299.00	208.28
		CO	415.87	1,821.49
		PM	71.17	311.71
		PM_{10}	71.17	311.71
		$PM_{2.5}$	71.17	311.71
SCRU4-1	Combined Heater Stack ***	NO_X	47.47	178.23
		VOC	4.27	16.02
		SO_2	29.47	65.84
		CO	65.16	244.63
		PM	5.90	22.13
		PM_{10}	5.90	22.13
		$PM_{2.5}$	5.90	22.13

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SCDHDS1	CDHDS1 Heater	NO_X	4.38	14.06
		VOC	0.39	1.26
		SO_2	2.72	5.19
		CO	6.00	19.30
		PM	0.54	1.75
		PM_{10}	0.54	1.75
		$PM_{2.5}$	0.54	1.75
SFCCU3-1	FCCU 3 Charge Heater	NO_X	9.91	25.31
		VOC	0.89	2.27
		SO_2	6.15	9.35
		CO	13.60	34.74
		PM	1.23	3.14
		PM_{10}	1.23	3.14
		$PM_{2.5}$	1.23	3.14
SHCU1-1	HCU No. 1 Reactor No.1 Heater	NO_X	4.20	15.77
		VOC	0.28	1.06
		SO_2	1.96	4.37
		CO	4.32	16.23
		PM	0.39	1.47
		PM_{10}	0.39	1.47
		$PM_{2.5}$	0.39	1.47

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SHCU1-2	HCU No. 1 Reactor No.2 Heater	NO_X	5.32	19.97
		VOC	0.36	1.35
		SO_2	2.48	5.53
		CO	5.48	20.56
		PM	0.50	1.86
		PM_{10}	0.50	1.86
		$PM_{2.5}$	0.50	1.86
SHCU1-3	HCU No. 1 Preflash Boiler	NO_X	7.19	26.98
		VOC	0.48	1.82
		SO_2	3.35	7.48
		CO	7.40	27.77
		PM	0.67	2.51
		PM_{10}	0.67	2.51
		$PM_{2.5}$	0.67	2.51
SHCU1-4	HCU No. 1 Fractionator Boiler	NO_X	7.20	31.54
		VOC	0.49	2.13
		SO_2	3.35	8.74
		CO	7.41	32.46
		PM	0.67	2.94
		PM_{10}	0.67	2.94
		$PM_{2.5}$	0.67	2.94

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
SHTU1-1	HTU No. 1 Charge Heater	NO_X	2.45	9.20
		VOC	0.22	0.83
		SO_2	1.52	3.40
		CO	3.36	12.62
		PM	0.30	1.14
		PM_{10}	0.30	1.14
		$PM_{2.5}$	0.30	1.14
SHTU2-1	HTU No. 2 Charge Heater	NO_X	3.78	14.19
		VOC	0.34	1.28
		SO_2	2.35	5.24
		CO	5.19	19.48
		PM	0.47	1.76
		PM_{10}	0.47	1.76
		$PM_{2.5}$	0.47	1.76
SHTU2-2	HTU No. 2 Reboiler	NO_X	2.94	11.04
		VOC	0.26	0.99
		SO_2	1.83	4.08
		CO	4.04	15.15
		PM	0.37	1.37
		PM_{10}	0.37	1.37
		$PM_{2.5}$	0.37	1.37

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SHTU3-1	HTU No. 3 Charge Heater	NO_X	4.21	15.79
		VOC	0.38	1.42
		SO_2	2.61	5.83
		CO	5.77	21.68
		PM	0.52	1.96
		PM_{10}	0.52	1.96
		$PM_{2.5}$	0.52	1.96
SHTU3-2	HTU No. 3 Reboiler	NO_X	4.23	14.48
		VOC	0.38	1.30
		SO_2	2.62	5.35
		CO	5.80	19.87
		PM	0.53	1.80
		PM_{10}	0.53	1.80
		$PM_{2.5}$	0.53	1.80
SHTU4-1	CHGE Heater 1	NO_X	3.83	9.15
		VOC	0.21	0.49
		SO_2	1.43	2.03
		CO	3.15	7.54
		PM	0.29	0.68
		PM_{10}	0.29	0.68
		$PM_{2.5}$	0.29	0.68

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SHTU4-2	CHGE Heater 2	NO_X	3.83	9.15
		VOC	0.21	0.49
		SO_2	1.43	2.03
		CO	3.15	7.54
		PM	0.29	0.68
		PM_{10}	0.29	0.68
		$PM_{2.5}$	0.29	0.68
SHTU4-3	Reboiler Heater	NO_X	2.33	6.66
		VOC	0.16	0.45
		SO_2	1.09	1.84
		CO	2.40	6.85
		PM	0.22	0.62
		PM_{10}	0.22	0.62
		$PM_{2.5}$	0.22	0.62
SHTU4-4	Recycle Gas Heater	NO_X	8.22	28.17
		VOC	0.55	1.90
		SO_2	3.83	7.81
		CO	8.46	29.00
		PM	0.77	2.62
		PM_{10}	0.77	2.62
		$PM_{2.5}$	0.77	2.62

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SHTU5	HTU5 Heater	NO_X	2.46	9.22
		VOC	0.38	1.42
		SO_2	2.61	5.81
		CO	2.56	9.62
		PM	0.52	1.96
		PM_{10}	0.52	1.96
		$PM_{2.5}$	0.52	1.96
SLCDU1-1	LCDU Charge Heater	NO_X	2.12	7.28
		VOC	0.19	0.65
		SO_2	1.32	2.69
		CO	2.91	9.99
		PM	0.26	0.90
		PM_{10}	0.26	0.90
		$PM_{2.5}$	0.26	0.90
SLCDU1-2	LCDU Charge Heater	NO_X	2.59	9.72
		VOC	0.23	0.87
		SO_2	1.61	3.59
		CO	3.55	13.35
		PM	0.32	1.21
		PM_{10}	0.32	1.21
		$PM_{2.5}$	0.32	1.21

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SMPU3-1	MPU Refined Oil Mix Heater	NO_X	3.31	12.61
		VOC	0.22	0.85
		SO_2	1.54	3.49
		CO	3.41	12.99
		PM	0.31	1.17
		PM_{10}	0.31	1.17
		$PM_{2.5}$	0.31	1.17
SMPU3-2	MPU No. 3 Extract Heater	NO_X	8.94	34.02
		VOC	0.60	2.29
		SO_2	4.16	9.43
		CO	9.20	35.02
		PM	0.83	3.17
		PM_{10}	0.83	3.17
		$PM_{2.5}$	0.83	3.17
SMPU4	MPU 4 Secondary Heater Stack	NO_X	0.72	3.15
		VOC	0.05	0.21
		SO_2	0.34	0.87
		CO	0.74	3.25
		PM	0.07	0.29
		PM_{10}	0.07	0.29
		$PM_{2.5}$	0.07	0.29

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
SMPU4	MPU 4 Secondary Heater Stack	NO_X	3.52	13.42
		VOC	0.24	0.90
		SO_2	1.64	3.72
		CO	3.62	13.82
		PM	0.33	1.25
		PM_{10}	0.33	1.25
		$PM_{2.5}$	0.33	1.25
SMPU4C	MPU No 4 Extract Heater	NO_X	9.07	39.74
		VOC	0.61	2.68
		SO_2	4.22	11.01
		CO	9.34	40.90
		PM	0.84	3.70
		PM_{10}	0.84	3.70
		$PM_{2.5}$	0.84	3.70
SCDHydro/SCHDS2	CDHydro/CDHDS2 Heater	NO_X	3.67	13.05
		VOC	0.50	1.76
		SO_2	3.42	7.23
		CO	7.56	26.87
		PM	0.68	2.43
		PM_{10}	0.68	2.43
		$PM_{2.5}$	0.68	2.43

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
SHCU1-5	HCU No. 1 Prefractionator Heater	NO_X	0.93	3.50
		VOC	0.25	0.94
		SO_2	1.74	3.88
		CO	3.84	14.43
		PM	0.35	1.31
		PM_{10}	0.35	1.31
		$PM_{2.5}$	0.35	1.31
SDCU1-1	Coker Heater No.1	NO_X	17.56	65.42
		VOC	1.18	4.41
		SO_2	8.17	18.12
		CO	18.07	67.34
		PM	1.64	6.09
		PM_{10}	1.64	6.09
		$PM_{2.5}$	1.64	6.09
SDCU1-2	Coker Heater No.2	NO_X	17.56	65.42
		VOC	1.18	4.41
		SO_2	8.17	18.12
		CO	18.07	67.34
		PM	1.64	6.09
		PM_{10}	1.64	6.09
		$PM_{2.5}$	1.64	6.09

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
STGTU1-2	Hot Oil Heater	NO_X	0.61	1.21
		VOC	0.03	0.07
		SO_2	0.23	0.27
		CO	0.50	1.00
		PM	0.05	0.09
		PM_{10}	0.05	0.09
		$PM_{2.5}$	0.05	0.09
STGTU2-2	Hot Oil Heater	NO_X	3.64	13.67
		VOC	0.20	0.74
		SO_2	1.36	3.03
		CO	3.00	11.25
		PM	0.27	1.02
		PM_{10}	0.27	1.02
		$PM_{2.5}$	0.27	1.02
SHTU3-3	HTU No.3 Hydrogen Heater	NO_X	0.70	2.63
		VOC	0.13	0.47
		SO_2	0.87	1.94
		CO	1.92	7.21
		PM	0.17	0.65
		PM_{10}	0.17	0.65
		$PM_{2.5}$	0.17	0.65

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SVPS2-1	VPS No.2 Common Heater Stack ***	NO_X	13.52	50.37
		VOC	1.82	6.79
		SO_2	12.59	27.91
		CO	27.84	103.70
		PM	2.52	9.38
		PM_{10}	2.52	9.38
		$PM_{2.5}$	2.52	9.38
SVPS2-2	VPS No. 2, No. 4 Atmospheric Heater	NO_X	2.80	10.51
		VOC	0.38	1.42
		SO_2	2.61	5.82
		CO	5.76	21.64
		PM	0.52	1.96
		PM_{10}	0.52	1.96
		$PM_{2.5}$	0.52	1.96
SVPS4-1	VPS No. 4, No. 3 Atmospheric Heater	NO_X	8.40	36.79
		VOC	0.75	3.31
		SO_2	5.22	13.59
		CO	11.53	50.50
		PM	1.04	4.57
		PM_{10}	1.04	4.57
		$PM_{2.5}$	1.04	4.57

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SVPS4-4	VPS No. 4 Naphtha Splitter Reboiler	NO_X	3.48	15.24
		VOC	0.31	1.37
		SO_2	2.16	5.63
		CO	4.78	20.92
		PM	0.43	1.89
		PM_{10}	0.43	1.89
		$PM_{2.5}$	0.43	1.89
SVPS4-2	Atmospheric Heater No. 1 (8)	NO_X	10.50	
		VOC	0.94	
		SO_2	6.52	
		CO	14.41	
		PM	1.30	
		PM_{10}	1.30	
		$PM_{2.5}$	1.30	
SVPS4-3	Atmospheric Heater No. 2 (8)	NO_X	10.50	
		VOC	0.94	
		SO_2	6.52	
		CO	14.41	
		PM	1.30	
		PM_{10}	1.30	
		$PM_{2.5}$	1.30	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SVPS4-5	Vacuum Heater No. 1	NO_X	8.70	
		VOC	0.78	
		SO_2	5.40	
		CO	11.94	
		PM	1.08	
		PM_{10}	1.08	
		$PM_{2.5}$	1.08	
SVPS4-6	Vacuum Heater No. 2	NO_X	8.70	
		VOC	0.78	
		SO_2	5.40	
		CO	11.94	
		PM	1.08	
		PM_{10}	1.08	
		$PM_{2.5}$	1.08	
SVPS4-7	Combined Heater Stack (8) (9)	NO_X	39.36	165.80
		VOC	3.54	15.49
		SO_2	24.44	63.68
		CO	54.02	236.62
		PM	4.89	21.41
		PM_{10}	4.89	21.41
		$PM_{2.5}$	4.89	21.41

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
STGTU1-1	Tail Gas Treating Unit No. 1 Incinerator	NO_X	6.00	18.22
		VOC	0.40	1.23
		SO_2	62.22	236.83
		CO	10.89	41.45
		PM	0.56	1.70
		PM_{10}	0.56	1.70
		$PM_{2.5}$	0.56	1.70
STGTU2-1	Tail Gas Treating Unit No. 2 Incinerator	NO_X	7.50	22.78
		VOC	0.40	1.23
		SO_2	62.22	236.83
		CO	10.89	41.45
		PM	0.56	1.70
		PM_{10}	0.56	1.70
		$PM_{2.5}$	0.56	1.70
Loading Operations				
FLR39	Loading Rack No. 39	VOC	0.44	0.34
Storage Tanks				
TK 1945	Storage Tank No. 1945	VOC	3.88	5.33
TK 2040	Storage Tank No. 2040	VOC	1.82	1.87
TK 2041	Tank 2041	VOC	7.32	6.64
TAL35144	Fresh Caustic	VOC	0.01	0.01
TAL35140	Fresh Sulfuric Acid Tank	H2SO4	0.29	0.02
TAL35141	Fresh Sulfuric Acid Tank	H2SO4	0.29	0.02

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
TAR01748	Storage Tank No. 1748	VOC (7)	Vapor	Recovery
TBP32451	Storage Tank No. 32451	VOC (7)	Vapor	Recovery
TBS01740	Storage Tank No. 1740	VOC (7)	Vapor	Recovery
TBS01741	Storage Tank No. 1741	VOC (7)	Vapor	Recovery
TK 1803	Storage Tank No. 1803	VOC (7)	Vapor	Recovery
TK 1804	Storage Tank No. 1804	VOC (7)	Vapor	Recovery
TDC01825	Storage Tank 1825	VOC (7)	Vapor	Recovery
TFT12824	Storage Tank No. 12824	VOC	29.10	0.23
TK 1930	Amine Surge tank	VOC	0.07	0.01
TML01247	Storage Tank No. 1247	VOC	5.08	8.87
TML01248	Storage Tank No. 1248	VOC	6.16	8.48
TML01250	Storage Tank No. 1250	VOC	5.63	7.33
TML01251	Storage Tank No. 1251	VOC	5.63	2.28
TML01252	Storage Tank No. 1252	VOC	6.17	7.03
TML01254	Storage Tank No. 1254	VOC	5.89	7.06
TML01490	Storage Tank No. 1490	VOC	1.33	5.31
TML01524	Storage Tank No. 1524	VOC	4.59	7.22
TML01525	Storage Tank No. 1525	VOC	0.51	1.71
TML01526	Storage Tank No. 1526	VOC	6.95	9.50
TML01663	Storage Tank No. 1663	VOC	6.94	5.27
TML01698	Storage Tank No. 1698	VOC	4.83	13.04
TML01699	Storage Tank No. 1699	VOC	4.82	10.44
TML01767	Storage Tank No. 1767	VOC	0.90	4.04

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
TML01768	Storage Tank No. 1768	VOC	0.89	3.77
TML01904	Storage Tank No. 1904	VOC	5.91	7.73
TML19272	Storage Tank No. 19272	VOC	5.52	5.76
TP108874	Storage Tank No. 8874	VOC	1.02	0.54
TP301697	Storage Tank No. 1697	VOC	2.13	1.55
TST01475	Storage Tank No. 1475	VOC	0.52	2.01
TST01510	Storage Tank No. 1510	VOC	1.36	4.87
TST01511	Storage Tank No. 1511	VOC	1.71	5.16
TST01530	Storage Tank No. 1530	VOC (7)	Vapor	Recovery
TST01553	Storage Tank No. 1553	VOC	1.74	5.21
TST01600	Storage Tank No. 1600	VOC	2.55	2.42
TST01601	Storage Tank No. 1601	VOC	1.67	5.28
TST01617	Storage Tank No. 1617	VOC (7)	Vapor	Recovery
TST01671	Storage Tank No. 1671	VOC	0.81	2.55
TST01679	Storage Tank No. 1679	VOC	4.37	4.37
TST01681	Storage Tank No. 1681	VOC (7)	Vapor	Recovery
TST01712	Storage Tank No. 1712	VOC	1.75	4.04
TST01718	Storage Tank No. 1718	VOC	0.04	0.02
TST01719	Storage Tank No. 1719	VOC	0.04	0.01
TST01775	Storage Tank No.1775	VOC	0.99	4.14
TST01787	Storage Tank No. 1787	VOC	0.51	2.24
TST01850	Storage Tank No. 1850	VOC (7)	Vapor	Recovery
TST01884	Storage Tank No. 1884	VOC (7)	Vapor	Recovery

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
TST01885	Storage Tank No. 1885	VOC	0.80	3.66
TST01886	Storage Tank No. 1886	VOC	3.13	8.7
TST01893	Storage Tank No. 1893	VOC	5.36	6.67
TST01894	Storage Tank No. 1894	VOC	4.55	7.91
TST01895	Storage Tank No. 1895	VOC	1.17	3.58
TST01900	Storage Tank No. 1900	VOC (7)	Vapor	Recovery
TST01913	Storage Tank No. 1913	VOC	0.66	2.61
TST01920	Storage Tank No. 1920	VOC	1.04	3.18
TST19194	Storage Tank No. 19194	VOC	1.09	4.87
TST21657	Storage Tank No. 21657	VOC	4.37	4.29
TST21774	Storage Tank No. 21774	VOC	4.82	5.92
TST21775	Storage Tank No. 21775	VOC	4.82	4.36
TVA01820	Storage Tank 1820	VOC	0.01	0.01
TVA01821	Storage Tank 1821	VOC	0.05	0.04
TWT01887	Storage Tank No. 1887	VOC (7)	Vapor	Recovery
TNKGRP2	Tank Group (6)	VOC	169.00	154.20
		Benzene	0.19**	0.30
		H_2SO_4	0.59	0.03

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
Vents				
SCRU4-2	Regen Vent Scrubber Emissions	NO_X	0.97	4.25
		SO_2	0.67	2.96
		PM	0.06	0.26
		PM_{10}	0.06	0.26
		$PM_{2.5}$	0.06	0.26
		HCl	0.06	0.24
		Chlorine	0.01	0.05
SVVMPU3-3	MPU No. 3 Vacuum System Emissions	VOC	1.50	6.60
Fugitive Emissions				
FHTU5	HTU5 Fugitives (5)	VOC	3.50	15.32
FCOKE1	Delayed Coking Unit Coke Handling Fugitives (5)	PM	0.01	0.01
		PM_{10}	0.01	0.01
		$PM_{2.5}$	0.01	0.01
F4MTR	4 MTR Cell (storm water)	VOC	0.01	0.01
F10MTR	10 MTR Cell (storm water)	VOC	0.01	0.01
F11MTR	11 MTR Cell (storm water)	VOC	0.01	0.01
FALKY4	ALKY 4 (5)	VOC	7.37	32.28
		Benzene	0.01	0.01
FARU1	ARU No. 1 Fugitive Emissions (5)	VOC	0.14	0.63
		Benzene	0.01	0.01
		Hydrogen Sulfide	0.22	0.96

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
FARU2	ARU No. 2 Fugitive Emissions (5)	VOC	0.08	0.33
		Benzene	0.01	0.01
		Hydrogen Sulfide	0.11	0.48
FARU3	ARU No. 3 Fugitive Emissions (5)	VOC	0.14	0.64
		Benzene	0.01	0.01
		Hydrogen Sulfide	0.11	0.48
FARU4	Fugitives ARU 4 (5)	VOC	0.17	0.74
		Benzene	0.01	0.01
		Hydrogen Sulfide	0.04	0.17
FASTU2	WW Collection Oil Recovery (5)	VOC	2.87	12.56
		Benzene	0.01	0.01
FBOTF	BOTF Fugitives (5)	VOC	0.28	1.22
FBSW	Bottoms, Solids, Water Tanks Farm Fugitives (5)	VOC	0.57	2.50
		Benzene	0.01	0.01
FCDHDS1	CDHDS1 Fugitive Emissions (5)	VOC	1.87	8.21
		Benzene	0.02	0.10
FCDHDS2	CDHDS2 Fugitive Emissions (5)	VOC	3.15	13.80
		Benzene	0.04	0.17
FCGHT	CGHT Fugitives (5)	VOC	0.01	0.01
FCRU4	CRU No. 4 Fugitive Emissions (5)	VOC	4.70	20.60
		Benzene	0.01	0.06
FDCU1	DCU 1 Fugitives (5)	VOC	6.75	29.58
		Benzene	0.01	0.06

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
FFCCU3	FCCU No. 3 Fugitive Emissions (5)	VOC	10.73	28.78
		Benzene	0.01	0.01
FGR-1	Flare Gas Recovery (5)	VOC	0.92	4.03
		Benzene	0.01	0.01
FGR-2	Flare Gas Recovery (5)	VOC	1.07	4.67
		Benzene	0.01	0.01
FHCU1	HCU No. 1 Fugitive Emissions (5)	VOC	4.26	18.66
		Benzene	0.01	0.01
FHTU1	HTU No. 1 Fugitive Emissions (5)	VOC	1.62	7.11
		Benzene	0.01	0.01
FHTU2	HTU No. 2 Fugitive Emissions (5)	VOC	1.23	5.38
		Benzene	0.01	0.01
FHTU3	HTU No. 3 Fugitive Emissions (5)	VOC	2.58	11.32
		Benzene	0.01	0.01
FHTU4	HTU No. 4 Fugitive Emissions (5)	VOC	4.24	18.59
		Benzene	0.01	0.01
FLCDU	LCDU Fugitive Emissions (5)	VOC	0.59	2.60
		Benzene	0.01	0.01
FLF	PAP Landfill	VOC	0.01	0.01
FLR43/44FE	Loading Rack Fugitives (5)	VOC	0.08	0.36
FMPU3	MPU No. 3 Fugitive Emissions (5)	VOC	0.69	3.02
		Benzene	0.01	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
FMPU4	MPU No. 4 Fugitive Emissions (5)	VOC	0.44	1.94
		Benzene	0.01	0.01
FNSGP	North Side Gas Plant Fugitive Emissions (5)	VOC	1.44	6.30
		Benzene	0.01	0.01
FPH27	Pump House No. 27 Fugitive Emissions (5)	VOC	7.30	32.01
		Benzene	0.01	0.01
FPH57	Pump House No. 57 Fugitive Emissions (5)	VOC	2.76	12.09
		Benzene	0.01	0.01
FRES5	Waterwater Reservoir No. 5	VOC	0.01	0.01
FRES10	Wastewater Reservoir No. 10	VOC	0.01	0.01
FSCTLA	Lift Station Fugitives (5)	VOC	0.08	0.33
		Benzene	0.01	0.01
FSRU2	Sulfur Recovery Unit No. 2 Fugitive Emissions (5)	SO_2	0.01	0.04
		Hydrogen Sulfide	0.01	0.05
FSRU3	Sulfur Recovery Unit No. 3 Fugitive Emissions (5)	SO_2	0.01	0.04
		Hydrogen Sulfide	0.01	0.05
FSRU4	Sulfur Recovery Unit No. 4 Fugitive Emissions (5)	SO_2	0.04	0.16
		Hydrogen Sulfide	0.04	0.17
FSWS1	ARU No. 3 Emissions (5) Fugitive	VOC	0.01	0.01
		Hydrogen Sulfide	0.16	0.72
		Ammonia	0.01	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
FTGTU1	Fugitives TGTU #1 (5)	SO_2	0.01	0.01
		CO	0.01	0.01
		Hydrogen Sulfide	0.01	0.01
FTGTU2	Fugitives TGTU #2 (5)	SO_2	0.01	0.01
		CO	0.01	0.01
		Hydrogen Sulfide	0.01	0.01
FUELTKSFE	Fuel Tanks Fugitives (5)	VOC	0.19	0.84
FU-Rack4	Loading Rack No. 4 Fugitives (5)	VOC	0.11	0.50
		Benzene	0.01	0.01
FVPS2	VPS No. 2 Fugitive Emissions (5)	VOC	3.60	15.75
		Benzene	0.01	0.03
FVPS4	VPS No. 4 Fugitive Emissions (5)	VOC	6.26	27.42
		Benzene	0.01	0.05
FWAGS	Wet Acid Gas Scrubber Fugitive Emissions (5)	VOC	0.51	2.22
		Benzene	0.01	0.01
FWSGP	WSGP Fugitives (5)	VOC	0.90	0.03
Flares				
EFCCU3	FCCU No. 3 Flare Stack Pilots	NO_X	0.01	0.03
		CO	0.06	0.24
		SO_2	0.01	0.01
		VOC	0.01	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
EHCU	HCU No. 1 Flare Stack Pilots	NO_X	0.01	0.04
		CO	0.07	0.32
		SO_2	0.01	0.01
		VOC	0.01	0.01
EHTU	HTU No. 4 Flare Stack Pilots	NO_X	0.01	0.03
		CO	0.05	0.22
		SO_2	0.01	0.01
		VOC	0.01	0.01
EVPS4	VPS No. 4 Flare Stack Pilots	NO_X	0.01	0.03
		CO	0.06	0.24
		SO_2	0.01	0.01
		VOC	0.01	0.01
ECRU4	CRU No. 4 Flare Stack Pilots	NO_X	0.01	0.03
		CO	0.06	0.24
		SO_2	0.01	0.01
		VOC	0.01	0.01
EDCU1	Delayed Coking Unit No. 1 Flare Stack Pilots	NO_X	0.01	0.03
		CO	0.05	0.22
		SO_2	0.01	0.01
		VOC	0.01	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
EFCCU1&2	ALKY 4 Flare Stack Pilots	NO_X	0.01	0.03
		CO	0.06	0.24
		SO_2	0.01	0.01
		VOC	0.01	0.01

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
NO_X - total oxides of nitrogen
SO_2 - sulfur dioxide
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
CO - carbon monoxide
H_2SO_4 - sulfuric acid
(4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.
(5) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.
(6) Refer to MAERT ATTACHMENT – TANK GROUP for the specific EPNs, Facility Identification Numbers, and source names included in this group.
(7) These tanks are authorized and routed to vapor recovery.
(8) The burners in the atmospheric heaters (FINS VPS4ATM1HT and VPS4ATM2HT) are authorized by Standard Permit 89842.
(9) The atmospheric and vacuum heaters (FINS VPS4ATM1HT, VPS4ATM2HT, VPS4VAC1HT, and VPS4VAC2HT) may exhaust through this common stack.

* Emission rates are based on and the facilities are limited by the following maximum operating schedule: 8,760 Hrs/yr

** Compliance with hourly emission limits is based on a rolling 12-month benzene concentration.

*** The FINS included in EPN SCRU4-1 are CRU4INTHT1, CRU4INTHT2, CRU4NHTCHT, CRU4PLATHT, and CRU4SRBL.

*** The FINS included in EPN SVPS2-1 are VPS2ATM1HT, VPS2ATM2HT, VPS2ATM3HT, VPS2VAC1HT, and VPS2VAC2HT.

Date: August 21, 2012

MAERT ATTACHMENT - TANK GROUP

Permit 8404

EMISSION POINT NUMBERSAND SOURCE NAMES

This table lists the emission point numbers, facility identification numbers, and source names for all facilities included in the tank emissions group Tank Group (EPN TNKGRP2).

FIN	EPN	EPN Description
TK 1247	TML01247	Tank TK 1247
TK 1248	TML01248	Tank TK 1248
TK 1250	TML01250	Tank TK 1250
TK 1251	TML01251	Tank TK 1251
TK 1252	TML01252	Tank TK 1252
TK 1254	TML01254	Tank TK 1254
TK 1475	TST01475	Tank TK 1475
TK 1490	TML01490	Tank TK 1490
TK 1510	TST01510	Tank TK 1510
TK 1511	TST01511	Tank TK 1511
TK 1524	TML01524	Tank TK 1524
TK 1525	TML01525	Tank TK 1525
TK 1526	TML01526	Tank TK 1526
TK 1530	TST01530	Tank TK 1530
TK 1535	TST01535	Tank TK 1535
TK 1553	TST01553	Tank TK 1553
TK 1600	TST01600	Tank TK 1600
TK 1601	TST01601	Tank TK 1601
TK 1617	TST01617	Tank TK 1617
TK 1663	TML01663	Tank TK 1663
TK 1671	TST01671	Tank TK 1671

FIN	EPN	EPN Description
TK 1679	TST01679	Tank TK 1679
TK 1681	TST01681	Tank TK 1681
TK 1697	TP301697	Tank TK 1697
TK 1698	TML01698	Tank TK 1698
TK 1699	TML01699	Tank TK 1699
TK 1712	TST01712	Tank TK 1712
TK 1718	TST01718	Tank TK 1718
TK 1719	TST01719	Tank TK 1719
TK 1740	TBS01740	Tank TK 1740
TK 1741	TBS01741	Tank TK 1741
TK 1748	TAR01748	Tank TK 1748
TK 1767	TML01767	Tank TK 1767
TK 1768	TML01768	Tank TK 1768
TK 1775	TST01775	Tank TK 1775
TK 1787	TST01787	Tank TK 1787
TK 1803	TK 1803	Tank TK 1803
TK 1804	TK 1804	Tank TK 1804
TK 1820	TVA01820	Tank TK 1820
TK 1821	TVA01821	Tank TK 1821
TK 1825	TDC01825	Tank TK 1825
TK 1850	TST01850	Tank TK 1850
TK 1873	TBS01873	Tank TK 1873
TK 1884	TST01884	Tank TK 1884
TK 1885	TST01885	Tank TK 1885

FIN	EPN	EPN Description
TK 1886	TST01886	Tank TK 1886
TK 1887	TWT01887	Tank TK 1887
TK 1893	TST01893	Tank TK 1893
TK 1894	TST01894	Tank TK 1894
TK 1895	TST01895	Tank TK 1895
TK 1900	TST01900	Tank TK 1900
TK 1904	TML01904	Tank TK 1904
TK 1913	TST01913	Tank TK 1913
TK 1920	TST01920	Tank TK 1920
TK 1930	TK 1930	Tank TK 1930
TK 1945	TK 1945	Tank TK 1945
TK 2040	TK 2040	Tank TK 2040
TK 2041	TK2041	Tank TK 2041
TK 8874	TP108874	Tank TK 8874
TK 12824	TFT12824	Tank TK 12824
TK 19194	TST19194	Tank TK 19194
TK 19272	TML19272	Tank TK 19272
TK 21657	TST21657	Tank TK 21657
TK 21774	TST21774	Tank TK 21774
TK 21775	TST21775	Tank TK 21775
TK 32451	TBP32451	Tank TK 32451