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DEPARTMENT OF HEALTH  
AND ENVIRONMENT

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Division of Environment

## AIR EMISSION SOURCE CONSTRUCTION PERMIT

**Source ID No.:** 1130003

**Effective Date:** DRAFT

**Source Name:** National Cooperative Refinery Association

**SIC Code:** 2911, Petroleum Refining

**NAICS:** 324110, Petroleum Refineries

**Source Location:** 1391 Iron Horse Road  
McPherson, KS 67460

**Mailing Address:** P.O. Box 1404  
McPherson, KS 67460

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**This permit is issued pursuant to K.S.A. 65-3008 as amended; and consists of the conditions contained herein, the permit application date March 2008, and all revisions. In the event that any conditions, requirements, or limitation contained herein is not in exact agreement with the permit application, or any of its revisions, the conditions, requirements, and/or limitations contained herein shall control.**

### **Description of Activity Subject to Air Pollution Control Regulations**

National Cooperative Refinery Association (NCRA) has proposed its "Heavy Crude Expansion Project (HCEP)" and its "Benzene Reduction Project (BRP)" at its petroleum refinery location in McPherson, Kansas. The HCEP will enable NCRA to feed approximately 50% heavy, sour Canadian crude to its McPherson refinery. The refinery's capacity will also be expanded from approximately 87,000 to 100,000 barrels per day. The BRP will allow the refinery to meet a federally mandated limitation on the benzene content of gasoline, which becomes effective on January 1, 2011.

DIVISION OF ENVIRONMENT  
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Proposed refinery modifications associated with these two projects include the installation of a new Delayed Coker Unit designed to convert asphalt into refined products and petroleum coke, a petroleum coke crusher, a crushed coke conveying system and associated railcar/truck load-out facility, a steam reforming hydrogen unit (#2 Hydrogen Unit) to supply hydrogen for hydrotreating refined products, a new amine regeneration unit, a third Claus sulfur recovery unit (#3 Sulfur Recovery Unit) to recover the additional sulfur from processing sour Canadian crude oil, 12 new tanks, and two new flares (Main Plant Flares A and B) to serve multiple refinery units. The BRP will involve the construction of a new distillation tower and associated support equipment, and will include replacing a vertical feed heat exchanger in the platformer with a larger heat exchanger.

Changes will be made within the No. 2 Crude Unit, Vacuum Unit, Distillate Hydrotreater Unit, Naptha Hydrotreater Unit, HF Alky Unit, Platformer Unit, No. 2 Sour Water Stripper, ATS Units, and tank farm. The two process heaters and some of the equipment from the existing delayed coker unit will be used to provide additional capabilities for processing high sulfur crude and increasing throughput in the No. 2 Crude Unit. Other parts of the existing delayed coker unit will be permanently removed from service, including its three drums, the drum vapor blowdown system, and the three existing Internal Combustion (IC) engine driven compressors. The main plant flare and seven or eight tanks will be permanently removed from service. In the Fluid Catalytic Cracking (FCC) Unit, five IC driven compressors will be shut down and replaced with one or more electric motor-driven compressors. Other changes will be made throughout the refinery to accommodate the new and modified equipment.

The HCEP/BRP constitutes a major modification under Prevention of Significant Deterioration (PSD) [40 CFR 52.21, incorporated at K.A.R. 28-19-17 and 28-19-350]. The project emissions increase is above PSD de-minimis thresholds for PM, PM<sub>10</sub>, and SO<sub>2</sub>. For these pollutants Best Available Control Technology (BACT) will be installed on the new emissions units and emission units that will be physically or operationally modified. These include process heaters (2 new and 3 modified), 2 new flares, new coke handling system, 2 new delayed coker unit drum vents, and a new Claus sulfur recovery plant.

The increase in emissions of hazardous air pollutants (HAPs) will be below the case-by-case Maximum Achievable Control Technology (MACT) thresholds of 10 tons/year for any single HAP and 25 tons/year for combined total HAPs for each refinery process unit. Additionally, because each unit is below the 10/25 ton per year thresholds, the new process units will be subject to the existing source MACT requirements of 40 CFR Part 63, Subpart CC (Petroleum Refinery NESHAP).

### **Significant Applicable Air Pollution Control Regulations**

The project, as proposed, is subject to Kansas Administrative Regulations (K.A. R.) relating to air pollution control. The following air quality regulations were determined to be applicable to this source:

1. K.A.R. 28-19-17 Prevention of Significant Deterioration of Air Quality.
2. K.A.R. 28-19-23 Hydrocarbon Emissions – Stationary Sources

3. K.A.R. 28-19-31 Indirect Heating Equipment Emissions – Emission Limitations.
4. K.A.R. 28-19-650(a)(3) Emissions Opacity Limits.
5. K.A.R. 28-19-720 New Source Performance Standards, which adopts 40 CFR Part 60 Subpart A, Standards of Performance for New Stationary Sources – General Provisions.
6. K.A.R. 28-19-720 New Source Performance Standards, which adopts 40 CFR Part 60 Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.
7. K.A.R. 28-19-720 New Source Performance Standards, which adopts 40 CFR Part 60 Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage vessels (including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.
8. K.A.R. 28-19-720 New Source Performance Standards, which adopts 40 CFR Part 60 Subpart GGG-a, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.
9. K.A.R. 28-19-720 New Source Performance Standards, which adopts 40 CFR Part 60 Subpart QQQ, VOC Emissions from Petroleum Refinery Wastewater Systems.
10. K.A.R. 28-19-735 Hazardous Air Pollutants, which adopts 40 CFR Part 61 Subpart A, National Emissions Standards for Hazardous Air Pollutants – General Provisions
11. K.A.R. 28-19-735 Hazardous Air Pollutants, National Emissions Standards for Hazardous Air Pollutants, which adopts 40 CFR Part 61 Subpart FF, National Emission Standards for Benzene Waste Operations.
12. K.A.R. 28-19-750 Hazardous Air Pollutants, Maximum Achievable Control Technology, which adopts 40 CFR Part 63 Subpart A, National Emission Standards for Hazardous Air Pollutants for Source Categories – General Provisions.
13. K.A.R. 28-19-750 Hazardous Air Pollutants, Maximum Achievable Control Technology, which adopts 40 CFR Part 63 Subpart CC, National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries.

### **Air Emission Unit Technical Specifications**

The following equipment or their equivalents are approved:

1. Delayed coker process unit (includes delayed coker unit, 2 drums, gas plant, Mercox Plus unit, and drain system).
2. Coke handling, conveying and storage system (includes wet coke handling and storage, enclosed coke crusher, belt feeder, transfer shed, crushed coke conveyor, and

associated railcar/truck load-out facility).

3. Hydrogen process unit (includes #2 Hydrogen unit, heater, PSA unit de-aerator, and drain system).
4. Main Plant Flare A and associated drain system.
5. Main Plant Flare B and associated drain system.
6. #3 Amine Regenerator and associated drain system.
7. Tanks TK-PH-A-37, TK-PH-A-38, TK-PH-A-39, TK-PH-J-13, TK-PH-J-14, and TK-PH-J-15.
8. One pressurized butane tank.
9. Five (5) pressurized propylene tanks.

Modifications to the following equipment or their equivalent are approved:

1. #2 Crude Unit.
2. Coker Unit (including 2 heaters).
3. Vacuum Unit (including heater).
4. ATS Units (including the addition of the #3 Sulfur Recovery Unit).
5. FCC Unit.
6. Distillate Hydrotreater Unit.
7. #2 Sour Water Stripper.
8. Naptha Hydrotreater Unit.
9. HF Alky Unit.
10. Platformer Unit (including heater EU-PLT-6).
11. Tank farm.
12. Drains from modified units.

Note: New connections will be made to certain existing flare headers.

The following equipment shall be permanently removed from service during the project:

1. Coker blowdown stack and 3 coke drums.
2. Coke loading system at the existing coker, and coker gas plant.
3. 3 coker compressors and associated internal combustion engines.
4. Main Plant flare.
5. 5 FCC compressors and associated internal combustion engines.
6. The following storage tanks: TK-PH-A-11, TK-PH-A-12, TK-PH-A-15, TK-PH-A-18, TK-PH-C-07, TK-PH-C-08, and TK-PH-C-15.

**Air Emission Estimates from the Proposed Activity**

Pollutant	Project Increases	Contemporaneous Emission Changes	Net Emission Changes
	Tons/yr	Tons/yr	Tons/yr
Particulate Matter (PM)	67	-3.1	63.90
Particulate Matter less than 10 Microns (PM <sub>10</sub> )	26	-3.1	22.90
Oxides of Nitrogen (NO <sub>x</sub> )	286	-395.8	- 109.80
Oxides of Sulfur (SO <sub>x</sub> )	307	-154.1	152.90
Carbon Monoxide (CO)	228	-357.2	-129.2
Volatile Organic Compounds (VOC)	91	-62.5	28.50

**Air Emission Limitations**

The permittee shall comply with the following requirements on and after the date on which the initial performance test is completed, but no later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

1. K.A.R. 28-19-650(a)(3): Opacity of visible emissions shall be limited to 20%.
2. 40 CFR Part 60: Main Plant Flare A and Main Plant Flare B shall be designed for and operated with no visible emissions as determined by Method 22, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours. [40 CFR 60.18(c)(1)]

3. 40 CFR Part 60 Subpart Ja: Except as provided in (4) and (5) below, the owner or operator of an affected flare shall not allow flow to each affected flare during normal operations of more than 7,080 standard cubic meters per day (m<sup>3</sup>/day) (250,000 standard cubic feet per day(scfd)) on a 30-day rolling average. The owner or operator of a newly constructed flare shall comply with the emission limit in this paragraph by no later than the date that flare becomes an affected flare subject to this subpart. The owner or operator of a modified flare shall comply with the emission limit in this paragraph by no later than 1 year after that flare becomes an affected flare subject to this subpart. [40 CFR 60.102a(g)(3)]
4. 40 CFR Part 60 Subpart Ja: The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from paragraph (g) of this section [No. 3 above]. [40 CFR 60.102a(h)]
5. 40 CFR Part 60 Subpart Ja: In periods of fuel gas imbalance that are described in the flare management plan required in section 60.103a(a), compliance with the emission limit in paragraph (g)(3) of this section [No. 3 above] is demonstrated by following the procedures and maintaining records described in the flare management plan to document the periods of excess fuel gas. [40 CFR 60.102a(i)]
6. 40 CFR Part 60 Subpart Ja: Each owner or operator that operates a flare that is subject to this subpart shall develop and implement a written flare management plan. The owner or operator of a newly constructed or reconstructed flare must develop and implement the flare management plan by no later than the date the flare becomes an affected flare subject to this subpart. The owner or operator of a modified flare must develop and implement the flare management plan by no later than 1 year after the date the flare becomes an affected flare subject to this subpart. The plan must include:  
.[40 CFR 60.103a(a)]
  - (a) A diagram illustrating all connections to the flare;
  - (b) Method for monitoring flow rate to the flare, including a detailed description of the manufacturer's specifications, including but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance, and quality assurance procedures for flare gas monitoring devices;
  - (c) Procedures to minimize discharges to the flare gas system during the planned start-up and shutdown of the refinery process units that are connected to the affected flare;
  - (d) Procedures to conduct a root cause analysis of any process upset or malfunction that causes a discharge to the flare in excess of 14,160 m<sup>3</sup>/day (500,000 scfd);
  - (e) Procedures to reduce flaring in cases of fuel gas imbalance (i.e., excess fuel gas for the refinery's energy needs); and
  - (f) Explanation of procedures to follow during times that the flare must exceed the limit in 60.102a(g)(3) [No. 3 above] (e.g., keep records of natural gas purchases

to support assertion that the refinery is producing more fuel gas than needed to operate the processes)

7. 40 CFR Part 60 Subpart Ja: Each owner or operator that operates a fuel gas combustion device or sulfur recovery plant subject to this subpart shall conduct a root cause analysis of any emission limit exceedance or process start-up, shutdown, upset, or malfunction that causes a discharge to the atmosphere in excess of 227 kilograms per day (kg/day) (500 lb per day (lb/day)) of SO<sub>2</sub>. For any root cause analysis performed, the owner or operator shall record the identification of the affected facility, the date and duration of the discharge, the results of the root cause analysis, and the action taken as a result of the root cause analysis. The first root cause analysis for a modified flare must be conducted no later than the first discharge that occurs after the flare has been an affected flare subject to this subpart for 1 year. [40 CFR 60.103a(b)]
8. 40 CFR Part 60 Subpart Ja: For the ATS Units, the owner or operator shall not discharge or cause the discharge of any gas to the atmosphere in excess of 250 ppm by volume (dry basis) of sulfur dioxide (SO<sub>2</sub>) at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points the owner or operator shall comply with the 250 ppmv limit for each process train or release point or comply with a flow weighted average of 250 ppmv for all release points from the sulfur recovery plant [40 CFR 60.102a(f)(1)(i)]. The current BACT limit for the ATS Units stack is more stringent than the NSPS Subpart Ja SO<sub>2</sub> limit, at 90 ppmv by volume (dry basis) of sulfur dioxide at zero percent O<sub>2</sub> [24-hour rolling average].
9. 40 CFR Part 60 Subpart Ja: For the ATS Units, periods of maintenance of the sulfur pit, during which the emission limit in paragraph (f)(1) [No. 8 above] shall not apply, shall not exceed 240 hours per year. The owner or operator must document the time periods during which sulfur pit vents were not controlled and measures taken to minimize emissions during these periods. Examples of these measures include not adding fresh sulfur or shutting off vent fans. [40 CFR 60.102a(f)(3)]
10. 40 CFR Part 60 Subpart Ja: For the coker heater and #2 Hydrogen Unit Heater, the owner or operator shall not discharge to the atmosphere any emissions of NO<sub>x</sub> in excess of 40 ppmv (dry basis, corrected to 0 percent excess air on a 24-hour rolling average basis. [40 CFR 60.102a(g)(2)]
11. 40 CFR Part 60 Subpart Ja: For the Coker Heater, #2 Hydrogen Unit Heater, Main Plant Flare A, Main Plant Flare B, and modified flares, the owner or operator shall not burn any fuel gas that contains H<sub>2</sub>S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H<sub>2</sub>S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis. [40 CFR 60.102a(g)(1)(ii)] The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from these limits. [40 CFR 60.102a(h)] An additional fuel sulfur limit of 80 ppmv [24-hour rolling average] applies to the total, combined refinery fuel gas fired in the Coker Heater and #2 Hydrogen Unit Heater.
12. 40 CFR Part 60 Subpart Ja: For the Delayed Coker Process Unit, the owner or operator shall depressure to 5 lb per square inch guage (psig) during reactor vessel

depressuring and vent the exhaust gases to the fuel gas system for combustion in a fuel gas combustion device. [40 CFR 60.103a(c)]

## **Permit Conditions**

### **40 CFR Part 60 Subpart A – General Provisions Requirements**

1. Compliance with the standards in this part, other than the opacity standards, will be determined in accordance with the performance tests specified in 40 CFR 60.8, unless otherwise specified in the applicable standard. [40 CFR 60.11(a)]
2. Compliance with opacity standards in this part shall be determined by conducting observation in accordance with specified methods, and for determining initial compliance, the minimum total time of observations shall be two hours for the performance test or other set of observations. [40 CFR 60.11(b)]
3. The opacity standards set forth in this part shall apply at all times except during periods of startup, shutdown, malfunction, and as otherwise provided in the applicable standard.
4. At all times, including period of startup, shutdown, and malfunction, owners and operators shall, to the extent practically possible, maintain and operate any affected facility, including associated air pollution control equipment, in a manner consistent with good air pollution practice for minimizing emissions. [40 CFR 60.11(d)]
5. Special provision set forth under an applicable subpart supersede any conflicting provisions in the this part. [40 CFR 60.11(f) and (g)]
6. No owner or operator subject to the provisions of this part shall build, erect, install, or use any article, machine, equipment or process, the use if which conceals an emission which would otherwise constitute a violation of an applicable standard. Such concealment includes, but is not limited to, the use of gaseous diluents to achieve compliance with an opacity standard or with a standard which is based on the concentration of a pollutant in the gases discharged to the atmosphere. [40 CFR 60.12]
7. Continuous monitoring system requirements are as described in 40 CFR 60.13.
8. Flare design and operation requirements are as described in 40 CFR 60.18.

### **BACT Limits for New and Modified Heaters, ATS Stack, and New Baghouses**

For the process heaters:

BACT for sulfur dioxide is established by limiting the sulfur content of the refinery fuel gas. The heaters at the facility are fueled by a common refinery fuel gas supply and the sulfur content of the fuel gas is measured on a continuous basis. The BACT is proposed as a sulfur limit of 160 ppm at 0% O<sub>2</sub> for a 3 hour rolling average, and 160 ppm at 0% O<sub>2</sub> for a 365 day rolling average.

This will effectively limit the sulfur content on all the process heaters at the facility to these new levels, due to the fact that there is only one common fuel gas supply for the heaters at the facility.

BACT for PM/PM<sub>10</sub> is 0.008 lb PM<sub>10</sub>/mmBtu for new and modified heaters burning refinery fuel gas. A different BACT for the No. 2 Hydrogen Plant heater is proposed due to the different fuel composition. BACT for the No. 2 Hydrogen Plant heater is proposed as 0.011 lb PM<sub>10</sub>/MMBtu.

For the main plant flares A and B:

BACT for sulfur dioxide and PM/PM<sub>10</sub> for the main plant flares consist of design and workplace standards since there is no currently feasible method to measure emissions exiting the flares. BACT is proposed as using a flare design that meets the requirements of the New Source Performance Standards Subpart A, Section 60.18 (40 CFR Part 60.18) and API recommended practice 520 and 521. Workplace standards include continuously monitoring the pilot flame with infrared sensors, maintaining a natural gas/refinery gas purge so that the heating value of gases to the flares is not less than 300 Btu/scf, and using steam assisted mixing at the flare tip for smokeless operation.

For the delayed coker unit steam vents:

BACT for sulfur dioxide and PM/PM<sub>10</sub> for the delayed coker steam vents consists of design and workplace standards. The high pressure coke drum relief gas will be vented to the coker fractionator overhead receiver and into the wet gas compressor for hydrocarbon recovery. NCRA will develop specific operating procedures for the coker steam vent with the intent of minimizing venting to the maximum extent practical. These procedures will be consistent with NSPS Subpart Ja work practice standards which require that the vents be recovered until the pressure is less than 5 psig.

For the petroleum coke handling system:

BACT for PM/PM<sub>10</sub> consists of a combination of workplace standards and emission limits. BACT for coke handling emissions downstream of the crusher consists of enclosed conveying and handling systems vented to fabric filters. The BACT limit for the Coke Transfer Shed baghouse and the Coke Load Out Silo baghouse is .005 grains PM<sub>10</sub> per dry standard cubic foot. The BACT proposed for the coke handling operations upstream of the crusher is a work place standard requiring coke moisture content to be maintained at a level that ensures no visible emissions occur from these operations.

For the sulfur recovery plant:

BACT for sulfur dioxide is established by limiting the SO<sub>2</sub> emissions from the existing ATS units to 90 ppmvd @ 0% O<sub>2</sub> for a 24 hour rolling average. The two existing ATS units also handle gases from the existing sulfur recovery plants, and vent to atmosphere through a common stack which is equipped with a Continuous Emission Monitoring System (CEMS) for SO<sub>2</sub>.

BACT for PM/PM<sub>10</sub> is based on technology using high efficiency mist eliminators on the gases exiting the ATS units. BACT will be established by PM<sub>10</sub> testing on the ATS stack, and the PM/PM<sub>10</sub> rate will be based on the test results, not to exceed 3.67 lb/hr PM / 7.76 lb/hr PM<sub>10</sub>.

The permittee shall comply with the following requirements on and after the date on which the initial performance test is completed, but no later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

1. The average fuel sulfur concentration of the total, combined refinery fuel gas fired in the Coker Heater and #2 Hydrogen Unit Heater shall not exceed 80 ppm by volume (dry basis) at zero percent O<sub>2</sub> [24-hour rolling average].
2. For the #2 Hydrogen Unit Heater only, fuel will be limited to combined use of 60% PSA purge gas, propane, or natural gas and 40% refinery gas, on a heat input basis, with the 40% portion monitored for compliance with the 80 ppm fuel sulfur concentration limit stated above.
3. The owner or operator will limit the discharge of any gases into the atmosphere from the ATS Units' stack to 90 ppm by volume (dry basis) of sulfur dioxide at zero percent O<sub>2</sub> [24-hour rolling average].
4. Emissions of PM/PM<sub>10</sub> from the new Coker Heater, two Existing Coker Unit Heaters, and Vacuum Unit Heater are limited to 0.008 lb/mmBtu based on the average of at least three test runs.
5. Emissions of PM/PM<sub>10</sub> from the #2 Hydrogen Unit Heater are limited to 0.011 lb/mmBtu based on the average of at least three test runs.
6. Emissions of PM and PM<sub>10</sub> from the ATS Units' stack shall be limited to 3.67 lb PM/hr and 7.76 lb PM<sub>10</sub>/hr. These limits are based on permits for other ATS units. If either limit is exceeded during the initial performance tests, NCRA may revise the BACT analysis for PM and PM<sub>10</sub>, and may propose new limits for incorporation into this permit based on the revised BACT analysis. A lower PM limit and/or lower PM<sub>10</sub> limit for the ATS Units' stack may be established during source testing performed based on a test protocol that specifies the statistical methodology that will be used to set the lower BACT limit(s) (see *Performance Testing* section of this permit).
7. Emissions of PM/PM<sub>10</sub> from the Coke Transfer shed Baghouse and Coke Load-Out Silo Baghouse are limited to 0.005 gr/dscf based on the average of at least three test runs conducted at each baghouse.

40 CFR Part 60 Subpart GGG-a Requirements for Equipment Components in VOC Service:

The group of all the equipment (defined in 40 CFR Part 60.591a) within the following process units are affected facilities:

Delayed Coker Unit  
#2 Hydrogen Unit  
Distillate Hydrotreater Unit  
#3 Amine Regenerator  
Vacuum Unit  
#2 Sour Water Stripper

Naphtha Hydrotreater Unit  
HF Alky Unit  
Platformer Unit

Compressors within the following process units are affected facilities:

Delayed Coker Unit  
#2 Hydrogen Unit  
Distillate Hydrotreater Unit  
FCC Unit - replacement electric compressor(s) only

The permittee shall comply with the following requirements as soon as practicable, but no later than 180 days after initial startup:

1. Equipment/compressors in the Distillate Hydrotreater Unit, Vacuum Unit, Platformer Unit, and FCC Unit are presumed to be in compliance with Subpart GGG-a if these components are in compliance with the VOC BACT (HON LDAR) requirements in the 6/27/2005 Revised PSD Permit for Clean Fuels Project.
2. The permittee shall demonstrate compliance with the requirements of 40 CFR Part 60 Subpart GGG-a for all related equipment within 180 days of initial startup.
3. Compliance will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified at 40 CFR 60.485a as applicable.

General:

4. The permittee shall comply with the general equipment leak standards in 40 CFR 60.482-1a [NSPS Subpart VV-a], as required by 40 CFR 60.592a. [40 CFR 60.482-1a]

Pumps in light liquid service:

5. The permittee shall comply with the equipment leak standards for pumps in 40 CFR 60.482-2a [NSPS Subpart VV-a], as required by 40 CFR 60.592a. [40 CFR 60.482-2a]

Compressors:

6. The permittee shall comply with the equipment leak standards for compressors in 40 CFR 60.482-3a [NSPS Subpart VV-a], as required by 40 CFR 60.592a. [40 CFR 60.482-3a]

Pressure relief devices in gas/vapor service:

7. The permittee shall comply with the equipment leak standards for pressure relief devices in gas/vapor service in 40 CFR 60.482-4a [NSPS Subpart VV-a], as required by 40 CFR 60.592a. [40 CFR 60.482-4a]

Sampling connection systems:

8. The permittee shall comply with the equipment leak standards for sampling connection systems in 40 CFR 60.482-5a [NSPS Subpart VV-a], as required by 40 CFR 60.592a. [40 CFR 60.482-5a]

Open-ended valves or lines:

9. The permittee shall comply with the equipment leak standards for open-ended valves or lines in 40 CFR 60.482-6a [NSPS Subpart VV-a], as required by 40 CFR 60.592a. [40 CFR 60.482-6a]

Valves in gas/vapor service and in light liquid service:

10. The permittee shall comply with the equipment leak standards for valves in gas/vapor service and in light liquid service, found in 40 CFR 60.482-7a [NSPS Subpart VV-a], as required by 40 CFR 60.592a. [40 CFR 60.482-7a]

Pumps, valves, and connectors in heavy liquid service, connectors in gas/vapor or light liquid service, and pressure relief devices in light liquid or heavy liquid service:

11. The permittee shall comply with the equipment leak standards for pumps, valves, and connectors in heavy liquid service and pressure relief devices in light liquid or heavy liquid service, found in 40 CFR 60.482-8a [NSPS Subpart VV-a], as required by 40 CFR 60.592a. [40 CFR 60.482-8a]
12. Connectors in gas/vapor or light liquid service are exempt from the requirements in 40 CFR 60.482-11a, provided the permittee complies with 40 CFR 60.482-8a for all connectors, not just those in heavy liquid service. [40 CFR 60.593a(g)] [Note: 40 CFR 60.482-11a was stayed from June 2, 2008 until August 2, 2008, see 73 FR 31376, June 2, 2008]

Delay of repair:

13. The permittee shall comply with the standards for delay of repair found in 40 CFR 60.482-9a [NSPS Subpart VV-a], as required by 40 CFR 60.592a. [40 CFR 60.482-9a]

Closed vent systems and control devices:

14. The permittee shall comply with the standards for closed vent systems and control devices in 40 CFR 60.482-10a [NSPS Subpart VV-a], as required by 40 CFR 60.592a. [40 CFR 60.482-10a]

Exceptions:

15. Compressors in hydrogen service are exempt from the requirements of 40 CFR §60.592a if an owner or operator demonstrates that a compressor is in hydrogen service. [40 CFR 60.593a(b)(1)] Each compressor is presumed not to be in hydrogen

service unless an owner or operator demonstrates that the piece of equipment is in hydrogen service. For a piece of equipment to be considered in hydrogen service, it must be determined that the percent hydrogen content can be reasonably expected always to exceed 50 percent by volume. For purposes of determining the percent hydrogen content in the process fluid that is contained in or contacts a compressor, procedures that conform to the general method described in ASTM E260-73, 91, or 96, E168-67, 77, or 92, or E169-63, 77, or 93 (incorporated by reference as specified in §60.17) shall be used. [40 CFR 60.593a(b)(2)]

16. An owner or operator may use engineering judgment rather than procedures in paragraph 40 CFR 60.593a (b)(2) of this section to demonstrate that the percent content exceeds 50 percent by volume, provided the engineering judgment demonstrates that the content clearly exceeds 50 percent by volume. When an owner or operator and the Administrator do not agree on whether a piece of equipment is in hydrogen service, however, the procedures in paragraph 40 CFR 60.593a (b)(2) of this section shall be used to resolve the disagreement. [40 CFR 60.593a(b)(3)(i)] If an owner or operator determines that a piece of equipment is in hydrogen service, the determination can be revised only after following the procedures in paragraph 40 CFR 60.593a (b)(2). [40 CFR 60.593a(b)(3)(ii)]
17. Any existing reciprocating compressor that becomes an affected facility under provisions of 40 CFR §60.14 or 40 CFR §60.15 is exempt from 40 CFR §60.482-3a(a), (b), (c), (d), (e), and (h) provided the owner or operator demonstrates that recasting the distance piece or replacing the compressor are the only options available to bring the compressor into compliance with the provisions of 40 CFR §60.482-3a(a), (b), (c), (d), (e), and (h). [40 CFR 60.593a(c)]
18. An owner or operator may use the following provision in addition to 40 CFR §60.485a(e): Equipment is in light liquid service if the percent evaporated is greater than 10 percent at 150 °C as determined by ASTM Method D86-78, 82, 90, 93, 95, or 96 (incorporated by reference as specified in 40 CFR §60.17). [40 CFR 60.593a(d)]
19. Open-ended valves or lines containing asphalt as defined in 40 CFR §60.591a are exempt from the requirements of 40 CFR §60.482-6a(a) through (c). [40 CFR 60.593a(f)]

40 CFR Part 60 Subpart QQQ Requirements for Wastewater Systems:

New individual drain systems (defined in 40 CFR Part 60.691) within the following units are affected facilities. Any aggregate facility connected to one of these new individual drain systems is also an affected facility:

Delayed Coker Unit  
#2 Hydrogen Unit  
#3 SRU  
Coke Handling System  
Main Plant Flares A and B

Individual drain systems that are modified within the following units, will be affected facilities:

#2 Crude Unit  
Distillate Hydrotreater Unit  
HF Alky Unit  
Platformer Unit  
#3 Amine Unit

1. The permittee shall comply with the requirements of 40 CFR 60.692-1 to 60.692-5 and with 40 CFR 60.693-1 and 60.693-2, except during periods of startup, shutdown, or malfunction. [40 CFR 60.692-1(a)]
2. Compliance with 40 CFR 60.692-1 to 60.692-5 and with 40 CFR 60.693-1 and 60.693-2 will be determined by review of records and reports, review of performance test results, and inspection using the methods and procedures specified in 40 CFR 60.696. [40 CFR 60.692-1(b)]
3. Each drain (except those drains not in active service) shall be equipped with water seal controls. [40 CFR 60.692-2(a)(1)]
4. Each drain in active service shall be checked by visual or physical inspection initially and monthly thereafter for indications of low water levels or other conditions that would reduce the effectiveness of the water seal controls. [40 CFR 60.692-1(a)(2)]
5. Each drain out of active service shall be checked by visual or physical inspection initially and weekly thereafter for indications of low water levels or other problems that could result in VOC emissions unless the permittee elects to install a tightly sealed cap or plug over a drain that is out of service, in which case inspections shall be conducted initially and semiannually to ensure caps or plugs are in place and properly installed. [40 CFR 60.692-2(a)(3) & (a)(4)]
6. Whenever low water levels or missing or improperly installed caps or plugs are identified, water shall be added or first efforts at repair shall be made as soon as practicable, but not later than 24 hours after detection, except as provided at 40 CFR 60.692-6. [40 CFR 60.692-2(a)(5)]
7. Junction boxes shall be equipped with a cover and may have an open vent pipe. The vent pipe shall be at least 90 cm (3 ft) in length and shall not exceed 10.2 cm (4 in) in diameter. [40 CFR 60.692-2(b)(1)]
8. Junction box covers shall have a tight seal around the edge and shall be kept in place at all times, except during inspection and maintenance. [40 CFR 60.692-2(b)(2)]
9. If a broken seal or gap is identified, first effort at repair shall be made as soon as practicable, but not later than 15 calendar days after the broken seal or gap is identified, except as provided at 40 CFR 60.692-6. [40 CFR 60.692-2(b)(4)]
10. Sewer lines shall not be open to the atmosphere and shall be covered or enclosed in a manner so as to have no visual gaps or cracks in joints, seals, or other emission interfaces. [40 CFR 60.692-2(c)(1)]

11. The portion of each unburied sewer line shall be visually inspected initially and semiannually thereafter for indication of cracks, gaps, or other problems that could result in VOC emissions. [40 CFR 60.692-2(c)(2)]
12. Whenever cracks, gaps, or other problems are detected, repairs shall be made as soon as practicable, but not later than 15 calendar days after identification, except as provided at 40 CFR 60.692-6. [40 CFR 60.692-2(c)(3)]
13. Refinery wastewater routed through new process drains and a new first common down-stream junction box, either as part of a new individual drain system or an existing individual drain system, shall not be routed through a downstream catch basin. [40 CFR 60.692-2(e)]

40 CFR Part 60 Subpart Kb Standards for Tanks TK-PH-A-38, TK-PH-A-39, and TK-PH-J-13

1. Tanks TK-PH-A-38, TK-PH-A-39, and TK-PH-J-13 shall comply with 40 CFR Part 60, Subpart Kb requirements found at 40 CFR Parts 60.110b through 60.116b.

40 CFR Part 63 Subpart A General Provisions for Sources Subject to 40 CFR 63 Subpart CC

1. At all times, including periods of startup, shutdown, and malfunction, owners or operators shall operate and maintain any affected source, including associated air pollution control equipment, in a manner to minimize emissions at least to the levels required by all relevant standards. [40 CFR 63.6(e)(1)(i)]
2. The owner or operator of an affected source shall develop and implement a written startup, shutdown, and malfunction plan. [40 CFR 63.6(e)(3)(i)]

40 CFR Part 63 Subpart CC Requirements for Equipment Leaks from Equipment Leaks, Miscellaneous Process Vents, Storage Vessels, and Wastewater

1. The permittee shall comply with the leak detection and repair program requirements as described under permit requirements for Subpart GGG-a, except:
  - (a) Provisions only apply to equipment in organic HAP service. [40 CFR 63.648(a)(1)]
  - (b) Calculation of percentage leaking equipment components may be done on a process unit basis or a source-wide basis. [40 CFR 63.648(a)(2)]
2. The permittee shall comply with the miscellaneous process vent provisions in 40 CFR 63.642, 63.643, 63.644, and 63.645. [40 CFR 63.642, 63.643, 63.644, and 63.645]
3. The permittee shall comply with the storage vessel provisions in 40 CFR 63.642 and 63.646. Tanks TK-PH-A-38 and TK-PH-A-39 will be new Group 1 storage vessels. All other new tanks will be either Group 2 storage vessels, or are exempt from Subpart CC. [40 CFR 63.642 and 63.646]

4. The permittee shall comply with the wastewater provisions in 40 CFR 63.642 and 63.647. [40 CFR 63.642 and 63.647]

#### Other Requirements

1. Water spray dust suppression shall be used during transfer of petroleum coke into the crusher, and on the contents of railcars before they are moved from the load-out facility.
2. The belt feeder and crushed coke conveyor shall be enclosed.
3. Tank TK-PH-J-14 shall be gas blanketed and the exhaust gas shall be recovered and routed to the process.
4. The API-DAF Project will be operational no later than March 31, 2009.

#### Recordkeeping

##### 40 CFR Part 60 Subpart A General Provisions Recordkeeping Requirements

1. The permittee shall maintain records of the occurrence of any startup, shutdown, or malfunction in the operation of any affected facility within the petroleum refinery. [40 CFR 60.7(b)]
2. Any owner or operator subject to the provisions of this subpart shall maintain a file of all measurements, including continuous monitoring system, monitoring device, and performance testing measurements; all continuous monitoring system performance evaluations; all continuous monitoring system or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by this part recorded in a permanent form suitable for inspection. The file shall be retained for at least two years following the date of such measurements, maintenance, reports, and records, except as described in 40 CFR 60.7(f)(1) through (f)(3). [40 CFR 60.7(f)]

##### 40 CFR Part 60 Subpart Ja and BACT Recordkeeping Requirements

1. Continuous monitoring systems shall be installed, calibrated, maintained, and operated, including: [40 CFR 60.106a and 60.107a]
  - (a) For the Coker Heater, #2 Hydrogen Unit Heater, Main Plant Flare A, Main Plant Flare B, and modified flares, an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H<sub>2</sub>S in the fuel gases before being burned in any fuel gas combustion device, except that fuel gases that qualify for one or more of the exemptions afforded in 40 CFR 60.107a(a)(3) and (b) need not be continuously monitored.. [40 CFR 60.107a(a)(2)]
  - (b) For the Coker Heater and #2 Hydrogen Unit Heater, an instrument for continuously monitoring and recording the concentration by volume (dry, zero percent O<sub>2</sub> basis) of NO<sub>x</sub> emissions into the atmosphere. The monitor must

include an O<sub>2</sub> monitor for correcting the data for excess air. [40 CFR 60.107a(c)]

- (c) For the Sulfur Recovery Plant, an instrument for continuously monitoring and recording the concentration (dry basis, zero percent excess air) of any SO<sub>2</sub> emissions into the atmosphere. The monitor shall include an oxygen monitor for correcting the data for excess air. [40 CFR 60.106a(a)(1)]
  - (d) For Main Plant Flare A, Main Plant Flare B, and modified flares, an instrument for continuously monitoring and recording the concentration of reduced sulfur in flare gas. [40 CFR 60.106a(d)]
  - (e) For Main Plant Flare A, Main Plant Flare B, and modified flares, a Continuous Parameter Monitoring System (CPMS) to measure and record the exhaust gas flow rate of each flare. [40 CFR 60.106a(e)]
2. For the purpose of reports, periods of excess emissions shall be determined and reported as follows: [40 CFR 60.106a(b) and 60.107a(d)]
- (a) SO<sub>2</sub> and NO<sub>x</sub> from fuel gas combustion:
    - i) All rolling 3-hour periods during which the average concentration of H<sub>2</sub>S as measured by the H<sub>2</sub>S continuous monitoring system exceeds 162 ppmv, all days in which the concentration of H<sub>2</sub>S as measured by daily stain tube sampling exceeds 162 ppmv, and all rolling 365-day periods during which the average concentration as measured by the H<sub>2</sub>S continuous monitoring system exceeds 60 ppmv. [40 CFR 60.107a(f)(2)]
    - ii) All rolling 24-hour periods during which the average sulfur concentration of the total, combined fuel gas fired in the #2 Hydrogen Unit Heater and Coker Heater, as measured by the H<sub>2</sub>S continuous monitoring system, exceeds 80 ppmv.
    - iii) All rolling 24-hour periods during which the average concentration of NO<sub>x</sub> as measured by the NO<sub>x</sub> continuous monitoring system exceeds 40 ppmv (dry, zero percent O<sub>2</sub> basis). [40 CFR 60.107a(f)(3)]
    - iv) All rolling 30-day periods during which the average flow rate to an affected flare as measured by the CPMS exceeds 250,000 scfd. [40 CFR 60.107a(f)(4)]
  - (b) SO<sub>2</sub> from the sulfur recovery plant
    - i) All 12-hour periods during which the average concentration of SO<sub>2</sub> as measured by the SO<sub>2</sub> continuous monitoring system exceeds 250 ppmv (dry, zero percent O<sub>2</sub> basis). [40 CFR 60.106a(b)(1)]
    - ii) All 24-hour periods during which the average concentration of SO<sub>2</sub> as measured by the SO<sub>2</sub> continuous monitoring system exceeds 90 ppmv

(dry, zero percent O<sub>2</sub> basis). [BACT]

3. The permittee shall comply with the recordkeeping requirements as specified in 40 CFR 60.108a. [40 CFR 60.108a(a)]

40 CFR Part 60 Subpart Kb Recordkeeping, Tanks TK-PH-A-38, TK-PH-A-39, and TK-PH-J-13

1. Unless otherwise noted, all records must be kept for at least 2 years. [40 CFR 60.115b(b)]
2. After installing control equipment in accordance with 40 CFR 60.112b(a)(2) (external floating roof), the owner or operator shall keep a record of each gap measurement performed as required by 40 CFR 60.113b(b). Each record shall identify the storage vessel in which the measurement was performed and shall contain:
  - (a) The date of measurement.
  - (b) The raw data obtained in the measurement.
  - (c) The calculations described in 40 CFR 60.113b (b)(2) and (b)(3).

40 CFR Part 60 Subpart GGG-a Recordkeeping Requirements for Equipment Components in VOC Service

1. An owner or operator of more than one affected facility subject to the provisions of this subpart may comply with the recordkeeping requirements for these facilities in one recordkeeping system if the system identifies each record by each facility. [40 CFR 60.486a(a)(2)]
2. The owner or operator shall record the information specified in paragraphs (a) through (v) of this section for each monitoring event required by 40 CFR 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a: [40 CFR 60.486a(a)(3)]
  - (a) Monitoring instrument identification.
  - (b) Operator identification.
  - (c) Equipment identification.
  - (d) Date of monitoring.
  - (e) Instrument reading.
3. When each leak is detected as specified in 40 CFR 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following requirements apply: [40 CFR 60.486a(b)]

- (a) A weatherproof and readily visible identification, marked with the equipment identification number, shall be attached to the leaking equipment.
  - (b) The identification on a valve may be removed after it has been monitored for 2 successive months as specified in 40 CFR 60.482-7a(c) and no leak has been detected during those 2 months.
  - (c) The identification on a connector may be removed after it has been monitored as specified in 40 CFR 60.482-11a(b)(3)(iv) and no leak has been detected during that monitoring.
  - (d) The identification on equipment, except on a valve or connector, may be removed after it has been repaired.
4. When each leak is detected as specified in 40 CFR 60.482-2a, 60.482-3a, 60.482-7a, 60.482-8a, 60.482-11a, and 60.483-2a, the following information shall be recorded in a log and shall be kept for 2 years in a readily accessible location: [40 CFR 60.486a(c)]
- (a) The instrument and operator identification numbers and the equipment identification number, except when indications of liquids dripping from a pump are designated as a leak.
  - (b) The date the leak was detected and the dates of each attempt to repair the leak.
  - (c) Repair methods applied in each attempt to repair the leak.
  - (d) Maximum instrument reading measured by Method 21 of appendix A-7 of this part at the time the leak is successfully repaired or determined to be nonrepairable, except when a pump is repaired by eliminating indications of liquids dripping.
  - (e) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.
  - (f) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.
  - (g) The expected date of successful repair of the leak if a leak is not repaired within 15 days.
  - (h) Dates of process unit shutdowns that occur while the equipment is unrepaired.
  - (i) The date of successful repair of the leak.
5. The following information pertaining to the design requirements for closed vent systems and control devices described in 40 CFR 60.482-10a shall be recorded and kept in a readily accessible location: [40 CFR 60.486a(d)]

- (a) Detailed schematics, design specifications, and piping and instrumentation diagrams.
  - (b) The dates and descriptions of any changes in the design specifications.
  - (c) A description of the parameter or parameters monitored, as required in 40 CFR 60.482-10a(e), to ensure that control devices are operated and maintained in conformance with their design and an explanation of why that parameter (or parameters) was selected for the monitoring.
  - (d) Periods when the closed vent systems and control devices required in 40 CFR 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a are not operated as designed, including periods when a flare pilot light does not have a flame.
  - (e) Dates of startups and shutdowns of the closed vent systems and control devices required in 40 CFR 60.482-2a, 60.482-3a, 60.482-4a, and 60.482-5a.
6. The following information pertaining to all equipment subject to the requirements in 40 CFR 60.482-1a to 60.482-11a shall be recorded in a log that is kept in a readily accessible location:
- (a) A list of identification numbers for equipment subject to the requirements of this subpart.
  - (b)
    - i) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of 40 CFR 60.482-2a(e), 60.482-3a(i), and 60.482-7a(f).
    - ii) The designation of equipment as subject to the requirements of 40 CFR 60.482-2a(e), 40 CFR 60.482-3a(i), or 40 CFR 60.482-7a(f) shall be signed by the owner or operator. Alternatively, the owner or operator may establish a mechanism with their permitting authority that satisfies this requirement.
  - (c) A list of equipment identification numbers for pressure relief devices required to comply with 40 CFR 60.482-4a.
  - (d)
    - i) The dates of each compliance test as required in 40 CFR 60.482-2a(e), 60.482-3a(i), 60.482-4a, and 60.482-7a(f).
    - ii) The background level measured during each compliance test.
    - iii) The maximum instrument reading measured at the equipment during each compliance test.

- (e) A list of identification numbers for equipment in vacuum service.
- (f) A list of identification numbers for equipment that the owner or operator designates as operating in VOC service less than 300 hr/yr in accordance with 40 CFR 60.482-1a(e), a description of the conditions under which the equipment is in VOC service, and rationale supporting the designation that it is in VOC service less than 300 hr/yr.
- (g) The date and results of the weekly visual inspection for indications of liquids dripping from pumps in light liquid service.
- (h) Records of the information specified in paragraphs (e)(8)(i) through (vi) of this section for monitoring instrument calibrations conducted according to sections 8.1.2 and 10 of Method 21 of appendix A-7 of this part and 40 CFR 60.485a(b).
  - i) Date of calibration and initials of operator performing the calibration.
  - ii) Calibration gas cylinder identification, certification date, and certified concentration.
  - iii) Instrument scale(s) used.
  - iv) A description of any corrective action taken if the meter readout could not be adjusted to correspond to the calibration gas value in accordance with section 10.1 of Method 21 of appendix A-7 of this part.
  - v) Results of each calibration drift assessment required by 40 CFR 60.485a(b)(2) (i.e., instrument reading for calibration at end of monitoring day and the calculated percent difference from the initial calibration value).
  - vi) If an owner or operator makes their own calibration gas, a description of the procedure used.
- (i) The connector monitoring schedule for each process unit as specified in 40 CFR 60.482-11a(b)(3)(v).
- (j) Records of each release from a pressure relief device subject to 40 CFR 60.482-4a.

7. The following information pertaining to all valves subject to the requirements of 40 CFR 60.482-7a(g) and (h), all pumps subject to the requirements of 40 CFR 60.482-2a(g), and all connectors subject to the requirements of 40 CFR 60.482-11a(e) shall be recorded in a log that is kept in a readily accessible location: [40 CFR 60.486a(f)]

- (a) A list of identification numbers for valves, pumps, and connectors that are designated as unsafe-to-monitor, an explanation for each valve, pump, or connector stating why the valve, pump, or connector is unsafe-to-monitor, and the plan for monitoring each valve, pump, or connector.

- (b) A list of identification numbers for valves that are designated as difficult-to-monitor, an explanation for each valve stating why the valve is difficult-to-monitor, and the schedule for monitoring each valve.
- 8. The following information shall be recorded for valves complying with 40 CFR 60.483-2a: [40 CFR 60.486a(g)]
  - (a) A schedule of monitoring.
  - (b) The percent of valves found leaking during each monitoring period.
- 9. The following information shall be recorded in a log that is kept in a readily accessible location: [40 CFR 60.486a(h)]
  - (a) Design criterion required in 40 CFR 60.482-2a(d)(5) and 60.482-3a(e)(2) and explanation of the design criterion; and
  - (b) Any changes to this criterion and the reasons for the changes.
- 10. The following information shall be recorded in a log that is kept in a readily accessible location for use in determining exemptions as provided in 40 CFR 60.480a(d): [40 CFR 60.486a(i)]
  - (a) An analysis demonstrating the design capacity of the affected facility,
  - (b) A statement listing the feed or raw materials and products from the affected facilities and an analysis demonstrating whether these chemicals are heavy liquids or beverage alcohol, and
  - (c) An analysis demonstrating that equipment is not in VOC service.
- 11. Information and data used to demonstrate that a piece of equipment is not in VOC service shall be recorded in a log that is kept in a readily accessible location. [40 CFR 60.486a(j)]
- 12. The provisions of 40 CFR 60.7(b) and (d) do not apply to affected facilities subject to this subpart. [40 CFR 60.486a(k)]

40 CFR Part 60 Subpart QQQ Recordkeeping Requirements for Wastewater Systems

- 1. All records shall be retained for a period of 2 years after being recorded unless otherwise noted. [40 CFR 60.697(a)]
- 2. For individual drain systems subject to 40 CFR 60.692-2, the locations, date, and corrective actions shall be recorded for each drain when the water seal is dry or otherwise breached, when a drain cap or plug is missing or improperly installed, or other problem is identified that could result in VOC emissions, as determined during the initial and periodic visual or physical inspection. [40 CFR 60.697(b)(1)]

3. For junction boxes subject to 40 CFR 60.692-2, the location, date, and corrective action shall be recorded for inspections required by 40 CFR 60.692-2(b) when a broken seal, gap, or other problem is identified that could result in VOC emissions. [40 CFR 60.697(b)(2)]
4. For sewer lines subject to 40 CFR 60.692-2, the location, date, and corrective action shall be recorded for inspections required by 40 CFR 60.692-2(c) when a problem is identified that could result in VOC emissions. [40 CFR 60.697(b)(3)]
5. If an emission point cannot be repaired or corrected without a process unit shutdown, the expected date of a successful repair shall be recorded. [40 CFR 60.697(e)(1)]
6. The reason for the delay as specified at 40 CFR 60.692-6 shall be recorded if an emission point or equipment problem is not repaired or corrected in the specified amount of time. [40 CFR 60.697(e)(2)]
7. The signature of the owner or operator (or designee) whose decision it was that repair could not be effected without refinery or process shut-down shall be recorded. [40 CFR 60.697(e)(3)]
8. The date of successful repair or corrective action shall be recorded. [40 CFR 60.697(e)(4)]
9. A copy of the design specifications for all equipment used to comply with the provisions of this subpart shall be kept for the life of the source in a readily accessible location. [40 CFR 60.697(f)(1)]
10. The following information pertaining to the design specifications shall be kept: [40 CFR 60.697(f)(2)]
  - (a) Detailed schematics, and piping and instrumentation diagrams. [40 CFR 60.697(f)(2)(i)]
  - (b) The dates and descriptions of any changes in the design specifications. [40 CFR 60.697(f)(2)(ii)]
11. If an owner or operator elects to install a tightly sealed cap or plug over a drain that is out of active service, the owner or operator shall keep for the life of a facility in a readily accessible location, plans or specifications which indicate the location of such drains. [40 CFR 60.697(g)]

40 CFR Part 63 Subpart A General Provisions Recordkeeping Requirements

1. Until a waiver of a recordkeeping or reporting requirement has been granted by the Administrator, the owner or operator of an affected source remains subject to the requirements of this section. [40 CFR 63.10(f)(1)]
2. Recordkeeping or reporting requirements may be waived upon written application to the Administrator if, in the Administrator's judgement, the affected source is achieving the relevant standards(s), or other conditions as described in 63.10(f)(2).

[40 CFR 63.10(f)(2)]

3. Further details regarding a waiver of recordkeeping or reporting requirements are as in 40 CFR 63.10(f)(3) through (f)(6). [40 CFR 63.10(f)(3) through (f)(6)]

40 CFR Part 63 Subpart CC Recordkeeping Requirements for Equipment Leaks, Miscellaneous Process Vents, Storage Vessels, and Wastewater

1. Refineries must keep records of reports submitted, monitoring results, and other records for at least 5 years. [40 CFR 63.642(e) and 63.654(1)(4)]. In addition, records must be kept so that they are accessible within 24 hours of request in either hand copy or computer-readable form. If acceptable to KDHE, reports may be submitted on electronic media. [40 CFR 63.642(e)]. The following records must be maintained on site:
  - (a) Records of the occurrence and duration of each startup, shutdown, or malfunction of operation and air pollution control equipment. [40 CFR 63.10(b)(2)(i-ii)]
  - (b) Records of actions that are consistent and inconsistent with the startup, shutdown, and malfunction plan. [40 CFR 63.10(b)(2)(iv-v)]
  - (c) Records of continuous monitoring system calibration checks (if continuous monitoring is required). [40 CFR 63.10(b)(x)]
  - (d) Complete test reports and reported results for any required performance tests. [40 CFR 63.654(1)(2)]
  - (e) Values of continuously monitored parameters. [40 CFR 63.654(1)(3)]
2. The signature of the person whose decision it was that a repair could not be effected without a process shutdown shall be recorded and retained for 2 years. [40 CFR 63.654(d)(1)(i)]
3. An owner or operator who determines that a compressor qualifies for the hydrogen service exemption in 40 CFR 63.648 shall also keep a record of the demonstration required by 40 CFR 63.648. [40 CFR 63.654(d)(3)]
4. An owner or operator must keep a list of identification numbers for valves that are designated as leakless, per 40 CFR 63.648(c)(10). [40 CFR 63.654(d)(4)]
5. An owner or operator must identify, either by list or location (area or refining process unit), equipment in organic HAP service less than 300 hours per year within refining process units subject to this subpart. [40 CFR 63.654(d)(5)]
6. An owner or operator must keep a list of reciprocating pumps and compressors determined to be exempt from seal requirements as per 40 CFR 63.648(f) and (i). [40 CFR 63.654(d)(6)]

7. Other recordkeeping requirements as described in 40 CFR 63.654(i) and Table 3 to Appendix to Subpart CC. [40 CFR 63.654(i)]

#### Other Recordkeeping

1. The permittee shall determine annual NO<sub>x</sub>, CO, and VOC emissions from all new, modified and affected units attributable to the HCEP/BRP, in tons per year on a calendar year basis, for a period of 10 years following resumption of regular operations after the change. [40 CFR 52.21(r)(6)]

#### Reporting

##### 40 CFR Part 60 Subpart A General Provisions

1. Each operator required to install continuous monitoring device(s) must submit excess emissions and monitoring system performance report(s) and/or summary report form(s) to KDHE semi-annually, except when more frequent reporting is specifically required by a subpart or more frequent reporting is deemed necessary by KDHE. [40 CFR 60.7(c)]
2. Within 60 days after achieving the maximum production rate at which the facility will operate, but not later than 180 days after initial startup of the facility, facility must conduct performance tests and submit written report of results to KDHE. [40 CFR 60.8(a)]
3. Until an adjustment of a time period or postmark deadline has been approved by KDHE under 40 CFR 60.19(f)(2-3), the owner or operator of an affected facility remains strictly subject to the requirements of 40 CFR 60.19. [40 CFR 60.19(f)(1)(i)]
4. An owner or operator shall request the adjustment provided for in paragraphs (f)(2) and (f)(3) of this section each time he or she wishes to change an applicable time period or postmark deadline specified in 40 CFR 60.19. [40 CFR 60.19(f)(1)(ii)]
5. Notwithstanding time periods or postmark deadlines specified in this part for the submittal of information to KDHE by an owner or operator, or the review of such information by KDHE, such time periods or deadlines may be changed by mutual agreement between the owner or operator and KDHE. An owner or operator who wishes to request a change in a time period or postmark deadline for a particular requirement shall request the adjustment in writing as soon as practicable before the subject activity is required to take place. The owner or operator shall include in the request whatever information he or she considers useful to convince KDHE that an adjustment is warranted. [40 CFR 60.19(f)(2)]
6. If, in KDHE's judgment, an owner or operator's request for an adjustment to a particular time period or postmark deadline is warranted, KDHE will approve the adjustment. KDHE will notify the owner or operator in writing of approval or disapproval of the request for an adjustment within 15 calendar days of receiving sufficient information to evaluate the request. [40 CFR 60.19(f)(3)]

7. If KDHE is unable to meet a specified deadline, he or she will notify the owner or operator of any significant delay and inform the owner or operator of the amended schedule. [40 CFR 60.19(f)(4)]

#### 40 CFR Part 60 Subpart Ja Reporting Requirements

1. The permittee shall comply with the reporting requirements as specified in 40 CFR 60.108a. [40 CFR 60.108a(a)]
2. The permittee shall notify KDHE of the specific monitoring provisions of 40 CFR 60.105a, 60.106a, and 60.107a with which the permittee seeks to comply. Notification shall be submitted with the notification of initial startup required by 40 CFR 60.7(a)(3). [40 CFR 60.108a(b)]

#### 40 CFR Part 60 Subpart Kb Reporting, Tanks TK-PH-A-38, TK-PH-A-39, and TK-PH-J-13

1. After installing control equipment in accordance with 40 CFR 60.112b(a)(2) (external floating roof), the owner or operator shall furnish reports as required below. [40 CFR 60.115b(b)]
2. Furnish KDHE with a report that describes the control equipment and certifies that the control equipment meets the specifications of 40 CFR 60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by 40 CFR 60.7(a)(3). [40 CFR 60.115b(b)(1)]
3. Within 60 days of performing the seal gap measurements required by 40 CFR 60.113b(b)(1), furnish KDHE with a report that contains: [40 CFR 60.115b(b)(2)]
  - (a) The date of measurement.
  - (b) The raw data obtained in the measurement.
  - (c) The calculations described in 40 CFR 60.113b (b)(2) and (b)(3).
4. After each seal gap measurement that detects gaps exceeding the limitations specified by 40 CFR 60.113b(b)(4), submit a report to KDHE within 30 days of the inspection. The report will identify the vessel and contain the information specified in paragraph (b)(2) of 40 CFR 60.115b and the date the vessel was emptied or the repairs made and date of repair. [40 CFR 60.115b(b)(4)]

#### 40 CFR Part 60 Subpart GGG-a Reporting Requirements for Equipment Components in VOC Service

1. Each owner or operator subject to the provisions of this subpart shall submit semiannual reports to KDHE beginning 6 months after the initial startup date. The initial semiannual report to KDHE shall include the following information: [40 CFR 60.487a(b)]
  - (a) Process unit identification.

- (b) Number of valves subject to the requirements of 40 CFR 60.482-7a, excluding those valves designated for no detectable emissions under the provisions of 40 CFR 60.482-7a(f).
  - (c) Number of pumps subject to the requirements of 40 CFR 60.482-2a, excluding those pumps designated for no detectable emissions under the provisions of 40 CFR 60.482-2a(e) and those pumps complying with 40 CFR 60.482-2a(f).
  - (d) Number of compressors subject to the requirements of 40 CFR 60.482-3a, excluding those compressors designated for no detectable emissions under the provisions of 40 CFR 60.482-3a(i) and those compressors complying with 40 CFR 60.482-3a(h).
  - (e) Number of connectors subject to the requirements of 40 CFR 60.482-11a.
2. All semiannual reports to KDHE shall include the following information, summarized from the information in 40 CFR 60.486a:
- (a) Process unit identification.
  - (b) For each month during the semiannual reporting period,
    - i) Number of valves for which leaks were detected as described in 40 CFR 60.482-7a(b) or 40 CFR 60.483-2a,
    - ii) Number of valves for which leaks were not repaired as required in 40 CFR 60.482-7a(d)(1),
    - iii) Number of pumps for which leaks were detected as described in 40 CFR 60.482-2a(b), (d)(4)(ii)(A) or (B), or (d)(5)(iii),
    - iv) Number of pumps for which leaks were not repaired as required in 40 CFR 60.482-2a(c)(1) and (d)(6),
    - v) Number of compressors for which leaks were detected as described in 40 CFR 60.482-3a(f),
    - vi) Number of compressors for which leaks were not repaired as required in 40 CFR 60.482-3a(g)(1),
    - vii) Number of connectors for which leaks were detected as described in 40 CFR 60.482-11a(b)
    - viii) Number of connectors for which leaks were not repaired as required in 40 CFR 60.482-11a(d), and
    - ix) The facts that explain each delay of repair and, where appropriate, why a process unit shutdown was technically infeasible.

- (c) Dates of process unit shutdowns which occurred within the semiannual reporting period.
  - (d) Revisions to items reported according to paragraph (b) of this section if changes have occurred since the initial report or subsequent revisions to the initial report.
3. An owner or operator electing to comply with the provisions of 40 CFR 60.483-1a or 60.483-2a shall notify KDHE of the alternative standard selected 90 days before implementing either of the provisions. [40 CFR 60.487a(d)]
  4. An owner or operator shall report the results of all performance tests in accordance with 40 CFR 60.8 of the General Provisions. The provisions of 40 CFR 60.8(d) do not apply to affected facilities subject to the provisions of this subpart except that an owner or operator must notify KDHE of the schedule for the initial performance tests at least 30 days before the initial performance tests. [40 CFR 60.487a(e)]

#### 40 CFR Part 60 Subpart QQQ Reporting Requirements for Wastewater System

1. Each owner or operator shall submit to KDHE within 60 days after initial startup a certification that the equipment necessary to comply with these standards has been installed and that the required initial inspections or tests of process drains, sewer lines, and junction boxes have been carried out in accordance with 40 CFR Part 60 Subpart QQQ. Thereafter, the owner or operator shall submit to KDHE semiannually a certification that all of the required inspections have been carried out in accordance with 40 CFR Part 60 Subpart QQQ. [40 CFR 60.698(b)(1)]
2. A report that summarizes all inspections when a water seal was dry or otherwise breached, when a drain cap or plug was missing or improperly installed, or when cracks, gaps, or other problems were identified that could result in VOC emissions, including information about the repairs or corrective action taken, shall be submitted initially and semiannually thereafter to KDHE. (40 CFR 60.698(c))

#### 40 CFR Part 63 Subpart CC Reporting Requirements for Equipment Leaks, Miscellaneous Process Vents, Storage Vessels, and Wastewater

1. The permittee shall submit the following reports: [40 CFR 63.654(e)]
  - (a) Periodic Reports as described in paragraph (g) of 40 CFR 63.654. [40 CFR 63.654(e)(2)]
  - (b) Other reports as described in paragraph (h) of 40 CFR 63.654. [40 CFR 63.654(e)(3)]
2. The permittee shall comply with the reporting provisions in 40 CFR 61.356 and 61.357 of 40 CFR part 61, subpart FF unless they are complying with the wastewater provisions specified in paragraph (o)(2)(ii) of 40 CFR 63.640. [40 CFR 63.654(a)]

#### Other Reporting

1. If the annual ton per year emissions from the project exceed the baseline actual emissions by a significant amount for NO<sub>x</sub>, CO, or VOC, and if such emissions differ from the documented preconstruction projection, the permittee shall submit a report to KDHE within 60 days after the end of such year containing the following:  
[40 CFR 52.21(r)(6)]
  - (a) Name, address and telephone number;
  - (b) The annual emissions as calculated; and
  - (c) Any other information that the permittee wishes to include in the report (e.g., an explanation as to why the emissions differ from the preconstruction projection).

### **Performance Testing**

The proposed project is subject to performance testing as required by K.A.R. 28-19-720 [40 CFR 60.8(a)] for units subject to 40 CFR Part 60 Subpart Ja, Subpart GGG-a, and Subpart QQQ. Certain of the emissions units are also subject to performance testing to demonstrate compliance with BACT limits per KAR 28-19-350. Performance testing shall be conducted within 60 days after achieving the maximum production rate at which the subject equipment will be operated but no later than 180 days after initial startup.

### **40 CFR Part 60 Subparts A, Ja and BACT Performance Testing Requirements for New Heaters, Flares, and ATS Units Stack**

1. The permittee shall conduct performance tests of the ATS Units stack, Coker Heater, #2 Hydrogen Unit Heater, Main Plant Flare A, Main Plant Flare B, and modified flares to demonstrate initial compliance with each applicable emissions limit in 40 CFR 60.102a according to the requirements of 40 CFR 60.8. [40 CFR 60.104a]
2. Within 120 days after achieving normal operation of the modified sulfur recovery plant, the permittee shall perform PM and PM<sub>10</sub> testing of the ATS Units stack based on a test protocol that specifies the statistical methodology that will be used to set the final BACT limit(s). The test protocol shall be submitted to KDHE for approval at least 90 days prior to conducting the test. Within 60 days of performing the test, the permittee shall submit a test report to KDHE and may propose a lower PM limit and/or a lower PM<sub>10</sub> limit. Upon approval, KDHE may administratively amend this permit to reflect the approved limit(s).
3. The permittee shall conduct opacity tests of the Main Plant Flare A and Main Plant Flare B to demonstrate initial compliance with the applicable opacity limit in 40 CFR 60.18(c)(1). Method 22 of Appendix A to 40 CFR 60 shall be used to determine the compliance of flares with the visible emission provisions. The observation period is 2 hours and observations shall be performed according to Method 22. [40 CFR 60.18(f)]
4. The owner or operator of the affected facility must provide KDHE at least 30 days prior notice of any performance test. Performance tests conducted for the purpose of determining compliance under 40 CFR 60.104a shall be conducted according to the applicable procedures specified under 40 CFR 60.104a(h), (i), and (j). [40 CFR

60.104a]

NSPS Subpart Kb Performance Testing Requirement for Tanks TK-PH-A-38, TK-PH-A-39, and TK-PH-J-13

1. The owner or operator shall determine the gap areas and maximum gap widths, between the primary seal and the wall of the storage vessel and between the secondary seal and the wall of the storage vessel, according the requirements of 40 CFR 60.113b(b). [40 CFR 60.113b(b)]

NSPS Subpart GGG-a Performance Testing Requirement for Equipment Leaks

1. The owner or operator of the affected facility must provide KDHE at least 30 days prior notice of any performance test. In conducting the performance tests required in 40 CFR 60.8, the owner or operator shall use as reference methods and procedures the test methods in Appendix A of 40 CFR 60 or other methods and procedures as specified in 40 CFR 60.485a, except as provided in 40 CFR 60.8(b). [40 CFR 60.485a(a)]

NSPS Subpart QQQ Performance Testing Requirement for Wastewater Systems

1. Before using any equipment installed in compliance with the requirements of 40 CFR 60.692-2, 60.692-3, 60.692-4, 60.692-5, or 60.693, the owner or operator shall inspect such equipment for indications of potential emissions, defects, or other problems that may cause the requirements of this subpart not to be met. Points of inspection shall include, but are not limited to, seals, flanges, joints, gaskets, hatches, caps, and plugs. [40 CFR 60.696(a)]

**Notification**

1. K.A.R. 28-19-720 (40 CFR 60.7) requires that written notifications of the following be submitted to KDHE for all 40 CFR Part 60 affected sources including units subject to Subpart Ja, Subpart Kb, Subpart GGG-a, and Subpart QQQ.
  - (a) the date of construction of the project postmarked no less than 30 days after such date; [40 CFR 60.7(a)(1)]
  - (b) the actual date of initial startup of the project postmarked within 15 days after such date; and [40 CFR 60.7(a)(3)]
  - (c) The permittee shall notify KDHE of the specific monitoring provisions of 40 CFR 60.105a, 60.106a, and 60.107a with which the permittee seeks to comply. Notification shall be submitted with the notification of initial startup required by 40 CFR 60.7(a)(3). [40 CFR 60.108a(b)]
  - (d) After installing control equipment in accordance with 40 CFR 60.112b(a)(2) (external floating roof), the permittee shall furnish Administrator with a report that describes the control equipment and certifies that the control equipment meets the specifications of 40 CFR 60.113b(b)(2), (b)(3), and (b)(4). This report shall be an attachment to the notification required by 40 CFR 60.7(a)(3). [40

CFR 60.115b(b)(1)]

- (e) the owner or operator of an affected facility shall provide at least 30 days prior notice of any performance test, including the anticipated date for conducting the initial opacity observations. [40 CFR 60.8(d) and 60.7(a)(6)]

Please use the enclosed NSPS notification form to submit the above required notifications.

- 2. K.A.R. 28-19-720 [40 CFR 60.7(a)(4)] also requires that written notification be submitted for any physical or operational change which may increase the emission rate of any air pollutant to which a standard applies. This notice shall be postmarked 60 days, or as soon as practicable, before the change is commenced and shall include information described in the following:
  - (a) The precise nature of the change;
  - (b) the productive capacity before and after the change; and
  - (c) the expected completion date of the change
- 3. Notify the North Central District Office Air Program Field Staff in Salina at (785) 827-9639 when the project is completed so that an evaluation can be conducted.

#### 40 CFR 60 Subpart Ja Notifications

- 1. The permittee shall comply with the notification requirements as specified in 40 CFR 60.108a. [40 CFR 60.108a(a)]

#### General Provisions

- 1. This document shall become void if the construction or modification has not commenced within 18 months of the effective date, or if the construction or modification is interrupted for a period of 18 months or longer.
- 2. A construction permit or approval must be issued by KDHE prior to commencing any construction or modification of equipment or processes, which results in an increase of potential-to-emit equal to or greater than the thresholds specified, by K.A.R. 28-19-300.
- 3. Upon presentation of credentials and other documents as may be required by law, representatives of KDHE (including authorized contractors of KDHE) shall be allowed to:
  - a. enter upon the premises where a regulated facility or activity is located or conducted or where records must be kept under conditions of this document;
  - b. have access to and copy, at reasonable times, any records that must be kept under conditions of this document;

- c. inspect at reasonable times, any facilities, equipment (including monitoring and control equipment) practices or operations regulated or required under this document; and
  - d. sample or monitor, at reasonable times, for the purposes of assuring compliance with this document or as otherwise authorized by the Secretary of KDHE, any substances or parameters at any location.
- 4. The emission unit or stationary source, which is the subject of this document, shall be operated in compliance with all applicable requirements of the Kansas Air Quality Act and the Federal Clean Air Act.
  - 5. This document is subject to periodic review and amendment as deemed necessary to fulfill the intent and purpose of the Kansas Air Quality Statutes and Regulations and rules promulgated in accordance therewith.
  - 6. This document does not relieve the facility of the obligation to obtain other approvals, permits, licenses or documents of sanction, which may be required by other federal, state or local government agencies.

**Permit Engineer**

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Dana S. Morris  
Professional Environmental Engineer  
Air Permitting Section

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Date Signed

DSM:saw  
c: Jennifer Nichols, NCDO  
C-7821

**PREVENTION OF SIGNIFICANT DETERIORATION (PSD)**

**PERMIT SUMMARY SHEET**

**Permit No.:** 1130003

**Source Name:** National Cooperative Refinery Association – Heavy Crude Expansion Project

**Source Location:** 1391 Iron Horse Road, McPherson, Kansas 67460

**Area Designation:**

K.A.R. 28-19-350, Prevention of significant deterioration of air quality, affects new major sources and major modifications to major sources in areas designated as "attainment" or "unclassifiable" under section 107 of the Clean Air Act (CAA) for any criteria pollutant (Table 1-1). The State of Kansas is classified as attainment for the National Ambient Air Quality Standards (NAAQS) (see Table 1-2) for all the criteria pollutants.

The McPherson area in McPherson County, Kansas, where this construction is taking place is in attainment for all the criteria pollutants.

**Project description:**

National Cooperative Refinery Association (NCRA) plans to build two new projects at their refinery located in McPherson, Kansas. The two projects are described as the Heavy Crude Expansion Project (HCEP) and the Benzene Reduction Project (BRP) and will occur concurrently.

The HCEP will include replacing the existing cokers with two new process units, 12 new tanks, a new amine regeneration unit, a new additional Claus sulfur recovery unit, two new flares and related changes to existing process units, tank farm and other equipment. The HCEP will enable NCRA to add sour Canadian crude to the feedstock at the McPherson refinery, and will increase the crude processing capacity from approximately 87,000 to an estimated 100,000 barrels per day.

The BRP will include the installation of a new column described as a naptha feed splitter, and the installation of a larger feed heat exchanger to replace the current feed heat exchanger. These changes are needed to enable the refinery to reduce the benzene content of gasoline to meet a federally mandated limit which becomes effective on January 1, 2011.

## **Significant Applicable Air Emission Regulations**

This source is subject to Kansas Administrative Regulations relating to air pollution control. The application for this permit was reviewed and will be evaluated for compliance with the following applicable regulations:

1. K.A.R. 28-19-300. Construction Permits and Approvals. Requires “Any person who proposes to construct or modify a stationary source or emissions unit shall obtain a construction permit before commencing such construction or modification.”
2. K.A.R. 28-19-350 Prevention of significant deterioration of air quality. "The provisions of K.A.R. 28-19-350 shall apply to the construction of major stationary sources and major modifications of major stationary sources in the areas of the state designated as an attainment area or an unclassified area for any pollutant under the procedures prescribed by section 107(d) of the federal clean air act (42 U.S.C. 7407 (d))."
3. K.A.R. 28-19-720 New Source Performance Standards: The new and modified fuel gas combustion devices, the new sulfur recovery plant, and the delayed coker unit drum vents are subject to 40 CFR Part 60, Subpart Ja- “Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After May 14, 2007.”
4. K.A.R. 28-19-720 New Source Performance Standards: The new and modified compressors and groups of equipment in process units are subject to 40 CFR Part 60, Subpart GGGa- “Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced After November 7, 2006.”
5. K.A.R. 28-19-720 New Source Performance Standards: The new and modified individual process drain systems, oil-water separators, and aggregate facilities are subject to 40 CFR Part 60, Subpart QQQ- “Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems.”
6. K.A.R. 28-19-720 New Source Performance Standards: The new and modified storage vessels are subject to 40 CFR Part 60, Subpart Kb- “Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction or Modification Commenced After July 23, 1984.”
7. K.A.R. 28-19-735 National Emission Standards for Hazardous Air Pollutants: The NCRA refinery is subject to 40 CFR Part 61, Subpart FF- “National Emission

Standards for Benzene Waste Operations.”

8. K.A.R. 28-19-750 Hazardous Air Pollutants; Maximum Achievable Control Technology: The NCRA refinery is subject to 40 CFR Part 63, Subpart CC- “National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries.”
9. K.A.R. 28-19-750 Hazardous Air Pollutants; Maximum Achievable Control Technology: The new sulfur recovery unit is subject to 40 CFR Part 63, Subpart UUU- “National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.”

**Air Emissions from the Project:**

Potential-to-emit of several of the PSD regulated pollutants from the NCRA refinery in McPherson exceed 100 tons per year. Hence, this facility is considered to be a major stationary source under provisions of K.A.R. 28-19-350.

Increases in potential-to-emit from the modified facility occur from the installation of new units and the increased production in existing units. Decreases in actual emissions occur from the shutdown and replacement of existing units. An emission netting analysis was performed to account for all emissions decreases and increases that occurred less than 5 years prior to March 2008. The results of the emissions analysis are summarized in the table below:

	<b>Emission Estimates, Tons/yr</b>						
<b>Pollutant:</b>	<b>PM</b>	<b>PM<sub>10</sub></b>	<b>NO<sub>x</sub></b>	<b>SO<sub>2</sub></b>	<b>CO</b>	<b>VOC</b>	<b>CO<sub>2</sub></b>
Emission Increases:	67	62	286	307	228	91	754,087
Shutdown Units:	-3.1	-3.1	-395.6	-152.3	-357.2	-51.9	-28,757
Other Contemporaneous Changes:	-0.018	-0.018	-0.2	-1.8	-0.031	-10.6	
Net Emission Changes:	63.9	58.9	- 109.8	152.9	- 129.2	28.5	725,330

The emissions of PM<sub>10</sub> and SO<sub>2</sub> increased by more than the PSD significance level and trigger review under the PSD regulations. Greater detail of the various emission calculations are contained in the appendices of the PSD permit application.

Hence, this project will be a major stationary source resulting in a net significant increase of PM/PM<sub>10</sub> and SO<sub>2</sub>. This project will be subject to the various aspects of K.A.R. 28-19-350 such as the use of best available control technology, ambient air quality analysis, and additional impacts upon soils, vegetation and visibility.

## **Best Available Control Technology (BACT)**

BACT requirement applies to each new or modified affected emissions unit and pollutant emitting activity. Also, individual BACT determinations are performed for each pollutant emitted from the same emission unit. Consequently, the BACT determination must separately address, for each regulated pollutant with a significant emissions increase at the source, air pollution controls for each emissions unit or pollutant emitting activity subject to review. National Cooperative Refinery Association was required to prepare a BACT analysis for KDHE's review according to the process described in Attachment A. KDHE's evaluation of the BACT for the process heaters, sulfur recovery units, coke handling system, flares, and delayed coker unit's analysis is presented in Attachment B.

In short KDHE has concurred with the National Cooperative Refinery Association for the following:

For the process heaters:

BACT for sulfur dioxide is established by limiting the sulfur content of the refinery fuel gas. The heaters at the facility are fueled by a common refinery fuel gas supply and the sulfur content of the fuel gas is measured on a continuous basis. The BACT is proposed as a sulfur limit of 160 ppm at 0% O<sub>2</sub> for a 3 hour rolling average, and 160 ppm at 0% O<sub>2</sub> for a 365 day rolling average. This will effectively limit the sulfur content on all the process heaters at the facility to these new levels, due to the fact that there is only one common fuel gas supply for the heaters at the facility.

A review of recently permitted process heaters shows that emission limits are all based on limiting fuel gas sulfur levels. The McPherson refinery has two existing fuel gas amine scrubbing systems and will install a third as part of the planned project. NCRA will design the new amine treating unit to achieve an H<sub>2</sub>S concentration of 50 ppmv on a 365-day rolling average basis. When this gas is combined with the fuel gas from the existing amine treating units, the fuel burned in the new and modified heaters will meet the newly proposed NSPS Subpart Ja sulfur levels of 160 ppmv @ 0% O<sub>2</sub> (3-hr rolling average) and 60 ppmv @ 0% O<sub>2</sub> (365-day rolling average). Although these fuel gas sulfur levels appear higher than some recently permitted units, they reflect the fact that the McPherson refinery gas is a composite of gas from the new amine gas scrubber and the fuel gas treated by the existing units, the excessive costs associated with achieving lower fuel gas sulfur levels, and the fact that other compounds besides H<sub>2</sub>S contribute to fuel gas sulfur levels. As a result, a higher SO<sub>2</sub> BACT limit is required for the new and modified heaters.

BACT for PM/PM<sub>10</sub> is 0.008 lb PM<sub>10</sub>/mmBtu for new and modified heaters burning refinery fuel gas. A different BACT for the No. 2 Hydrogen Plant heater is proposed due to the different fuel composition. BACT for the No. 2 Hydrogen Plant heater is proposed as 0.011 lb PM<sub>10</sub>/MMBtu.

For the main plant flares A and B:

BACT for sulfur dioxide and PM/PM<sub>10</sub> for the main plant flares consist of design and workplace standards since there is no currently feasible method to measure emissions exiting the flares. BACT is proposed as using a flare design that meets the requirements of the New Source Performance Standards Subpart A, Section 60.18 (40 CFR Part 60.18) and API recommended practice 520 and 521. Workplace standards include continuously monitoring the pilot flame with infrared sensors, maintaining a natural gas/refinery gas purge so that the heating value of gases to the flares is not less than 300 Btu/scf, and using steam assisted mixing at the flare tip for smokeless operation.

For the delayed coker unit steam vents:

BACT for sulfur dioxide and PM/PM<sub>10</sub> for the delayed coker steam vents consists of design and workplace standards. The high pressure coke drum relief gas will be vented to the coker fractionator overhead receiver and into the wet gas compressor for hydrocarbon recovery. NCRA will develop specific operating procedures for the coker steam vent with the intent of minimizing venting to the maximum extent practical. These procedures will be consistent with NSPS Subpart Ja work practice standards which require that the vents be recovered until the pressure is less than 5 psig.

For the petroleum coke handling system:

BACT for PM/PM<sub>10</sub> consists of a combination of workplace standards and emission limits. BACT for coke handling emissions downstream of the crusher consists of enclosed conveying and handling systems vented to fabric filters. The BACT limit for the Coke Transfer Shed baghouse and the Coke Load Out Silo baghouse is .005 grains PM<sub>10</sub> per dry standard cubic foot. The BACT proposed for the coke handling operations upstream of the crusher is a work place standard requiring coke moisture content to be maintained at a level that ensures no visible emissions occur from these operations.

For the sulfur recovery plant:

BACT for sulfur dioxide is established by limiting the SO<sub>2</sub> emissions from the existing ATS units to 90 ppmvd @ 0% O<sub>2</sub> for a 24 hour rolling average. The two existing ATS units also handle gases from the existing sulfur recovery plants, and vent to atmosphere through a common stack which is equipped with a Continuous Emission Monitoring System (CEMS) for SO<sub>2</sub>.

BACT for PM/PM<sub>10</sub> is based on technology using high efficiency mist eliminators on the gases exiting the ATS units. BACT will be established by PM<sub>10</sub> testing on the ATS stack, and the PM/PM<sub>10</sub> rate will be based on the test results, not to exceed 3.67 lb/hr PM / 7.76 lb/hr PM<sub>10</sub>.

### **Ambient Air Impact Analysis**

The owner or operator of a proposed source or modification must demonstrate that allowable emission increases from the proposed source, in conjunction with all other applicable emissions increases or reductions, would not cause or contribute to air pollution in violation of:

- 1) any national ambient air quality standard (NAAQS) in any air quality control region; or
- 2) any applicable maximum allowable increase over the baseline concentration in any area.

NCRA used EPA approved dispersion modeling guidelines (incorporated as Appendix W of 40 CFR 51) to predict the ambient air impacts. The AERMOD model was used to determine the maximum predicted ground-level concentration for each pollutant and applicable averaging period resulting from various operating loads.

The SO<sub>2</sub> screening analysis maximum concentrations for the HCEP and BRP project were below the modeling significance thresholds for both 3-hour and 24-hour averaging periods. The SO<sub>2</sub> screening analysis was run assuming that the refinery fuel gas sulfur content would not exceed 80 ppmv H<sub>2</sub>S at 0% O<sub>2</sub> on a 24-hour basis. NCRA has proposed this 24 hour refinery fuel gas sulfur limitation in lieu of a more detailed SO<sub>2</sub> ambient impact analysis.

The PM<sub>10</sub> screening analysis maximum concentrations for the active and inactive pile utilization scenarios were below the modeling significance thresholds for both 24-hour and annual averaging periods. The maximum predicted concentrations were found to be 3.4 micrograms per cubic meter (ug/m<sup>3</sup>) and 0.8 ug/m<sup>3</sup> for the 24-hour and annual averaging periods, respectively. The significance levels for PM<sub>10</sub> are 5 and 1 ug/m<sup>3</sup> for the 24-hour and annual averaging periods, respectively.

### **Additional Impact Analysis:**

NCRA was required to provide an analysis of the impairment to visibility and impacts on plants, soils and, vegetation that would occur as a result of this project and to what extent the emissions from the proposed modification impacts the general commercial, residential, industrial and other growth.

### **Visibility Impairment Analysis**

NCRA conducted a visibility degradation analysis for the particulate matter emissions from the proposed modification. NCRA used the document "Workbook for Plume Visual Impact Screening and Analysis", EPA 450/4-88-015, September 1988, and the EPA approved dispersion modeling procedure "VISCREEN" for guidance. A visibility analysis is performed for Class I (visibility-sensitive) areas located within 100 kilometers of a proposed facility. There are no

Class I areas in Kansas. The analysis was done at the Harvey County park which is located approximately 30 kilometers southwest of the refinery. The VISCREEN model results indicated no significant impact on visibility at the Harvey County park location.

## **Impacts on Vegetation**

In accordance with 40 CFR 52.21(o)(1), the owner shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the modification to the source. NCRA determined that the proposed facility and the associated increases of SO<sub>2</sub> and PM<sub>10</sub> are not expected to have significant effects on vegetation.

Air pollutants can affect vegetation through direct absorption through the foliage, or uptake from the soil of trace elements deposited in the soil. The effects of air pollution on vegetation can include visible damage to foliage and fruit, changes in metabolic function, adverse changes in plant activity, and crop yield reduction. The effects of air pollutants on vegetation fall into three categories: acute (short exposure to high concentration), chronic (lower concentration over months or years), and long term (abnormal changes to ecosystems and physiological alterations in organisms that occur gradually over very long time periods).

Sources of particulate due to the proposed project include material handling activities, unloading, conveyance, drop points, storage piles, and movement of heavy equipment on unpaved roads. The emission sources are low height and low velocity, so they contribute to localized deposition of PM<sub>10</sub>. Fuel combustion has wider dispersion. PM<sub>10</sub> sources can potentially affect vegetation in several ways. Emissions may physically block plant and tree stomates, or may affect leaf adsorption and reflectance (which hinders heat exchange and photosynthesis). Trace elements in PM<sub>10</sub> may be toxic to plants. The physical effects of PM<sub>10</sub> are acted on by wind and rain, and the toxicity is determined mostly by soil and plant characteristics. Plant toxicity from trace elements is mainly based on the interaction between soil and plants and occurs from plant uptake of trace elements deposited in the soil. The concentration of PM<sub>10</sub> has been compared to the NAAQS for predicting the physical / non-toxicity effects on vegetation. EPA has stated that “for most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary national ambient air quality standards (NAAQS) will not result in harmful effects” (see reference in permit application). The maximum predicted off-site concentrations are well below the maximum allowable NAAQS, and therefore are not expected to negatively impact vegetation or soils in the area.

SO<sub>2</sub> emissions come from combustion of refinery fuel gas in the process heaters and from the exhaust gas from the ATS plants. Many factors contribute to vegetation effects of SO<sub>2</sub>, including atmospheric conditions. SO<sub>2</sub> impacts are analyzed primarily through dispersion modeling to predict ground level concentrations from the proposed project. Short and long term exposures may have detrimental effects on many plant species, and several studies have been conducted studying the effects of SO<sub>2</sub> on vegetation (see application for references). Symptoms of SO<sub>2</sub> injury in leaves are interveinal necrotic blotches in angiosperms and red brown banding

in gymnosperms. A number of the plant species studied include those in the McPherson area. Injury threshold concentrations vary by species and dose: 131-5240 ug/m<sup>3</sup> for 8-hours, 393-3930 ug/m<sup>3</sup> for 2-hours, 1310 ug/m<sup>3</sup> for 4 hours. SO<sub>2</sub> modeled concentrations were significantly lower for the proposed project at 14.5 ug/m<sup>3</sup> for 3-hours, 4.3 ug/m<sup>3</sup> for 24-hours. Long term exposures in the range 43-1198 ug/m<sup>3</sup> had some negative effects, but SO<sub>2</sub> modeled concentrations were significantly lower at 0.6 ug/m<sup>3</sup>. Process heaters in this project are utilizing BACT to minimize SO<sub>2</sub> emissions, complying with the NAAQS and state and federal regulations, and have emissions below damage thresholds available in referenced literature. Therefore, SO<sub>2</sub> concentrations are not expected to exceed adverse impact levels on vegetation.

Air pollutants can act together to cause injury to or decrease the functioning of plants. Concentrations of pollutants in studies referenced are substantially higher than those occurring as a result of this project. Consequently, no synergistic effects of the air pollutants are expected to inhibit vegetation at or near the NCRA refinery at McPherson, Kansas.

### **Impacts on Soils**

Sulfates caused by SO<sub>2</sub> deposition on soil can be beneficial and detrimental to soils depending on its composition. However, given the low emission levels and the soils in the vicinity of the project, the SO<sub>2</sub> emissions from the project should not significantly affect the soils in the area.

### **Growth in Commercial, Residential and Industrial activity**

This modification at the NCRA facility will stimulate an increase in the local labor force during the construction phase in the McPherson area, but the increase will be temporary, short lived, and will not result in permanent/significant commercial and residential growth occurring in the vicinity of the refinery.

## **Attachment A**

### **KEY STEPS IN THE "TOP-DOWN" BACT ANALYSIS**

#### **STEP 1: IDENTIFY ALL POTENTIAL AVAILABLE CONTROL TECHNOLOGIES.**

The first step in a "Top-Down" analysis is to identify, for the emission unit in question, "all available" control options. Available control options are those air pollution control technologies or techniques with a PRACTICAL POTENTIAL FOR APPLICATION to the emissions unit and the regulated pollutant under review. This includes technologies employed outside of the United States. Air pollution control technologies and techniques include the application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant.

#### **STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS.**

The technical feasibility of the control options identified in Step 1 is evaluated with respect to the source-specific (or emissions unit specific) factors. In general, a demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

#### **STEP 3: RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS.**

All remaining control alternatives not eliminated in Step 2 are ranked and then listed in order of over-all control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- 1) control efficiencies;
- 2) expected emission rate;
- 3) expected emission reduction;
- 4) environmental impacts;
- 5) energy impacts; and
- 6) economic impacts.

#### **STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS.**

The applicant presents the analysis of the associated impacts of the control option in the listing. For each option, the applicant is responsible for presenting an objective evaluation of

each impact. Both beneficial and adverse impacts should be discussed and, where possible, quantified. In general, the BACT analysis should focus on the direct impact of the control alternative. The applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. In the event the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be fully documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology cannot be eliminated.

**STEP 5: SELECT BACT.**

The most effective control option not eliminated in Step 4 is proposed as BACT for the emission unit to control the pollutant under review.

**Attachment B**  
**KANSAS DEPARTMENT OF HEALTH AND ENVIRONMENT'S EVALUATION**  
**OF NATIONAL COOPERATIVE REFINERY ASSOCIATION**  
**McPHERSON REFINERY HEAVY CRUDE EXPANSION PROJECT**  
**PROPOSED BACT OPTIONS**

National Cooperative Refinery Association evaluated the BACT analysis to control SO<sub>2</sub> and PM<sub>10</sub> emissions from new and modified equipment associated with the Heavy Crude Expansion Project and the Benzene Reduction Project at the NCRA refinery located in McPherson, Kansas.

**SO<sub>2</sub> BACT for the Process Heaters**

Three different sulfur dioxide control techniques were evaluated:

- 1) Gaseous Fuel Sulfur limitations: Use of natural gas only.
- 2) Flue Gas Desulfurization: Use of scrubbers to control SO<sub>2</sub> emissions.
- 3) Gaseous Fuel Sulfur limitations: Use of low sulfur refinery gas.

The use of 100% natural gas was determined to be technically unfeasible as a control option. This option would create an excess of refinery fuel gas. The excess refinery fuel gas would have to be disposed of by flaring, which would result in the SO<sub>2</sub> emissions being transferred from the heaters to the flare.

The use of flue gas desulfurization was determined to be technically feasible. The relatively small amount of sulfur dioxide emission reductions achieved made this option economically unfeasible.

A new amine scrubbing system will be installed as part of this project. The unit will be designed to achieve 50 ppmv H<sub>2</sub>S on an annual basis in the gases exiting the amine unit. This scenario was used as baseline in the BACT analysis. The option of designing the unit to achieve 35 ppmv H<sub>2</sub>S was also evaluated. The 35 ppmv option was determined not to be cost-effective and also increased energy consumption, which would offset some of the reductions achieved by removing more of the sulfur in the fuel gas.

NCRA has proposed to limit the sulfur content of the refinery fuel gas system. They are proposing to limit the H<sub>2</sub>S in the fuel gas system to 160 ppmv @ 0% O<sub>2</sub> on a 3 hour rolling average and limit the concentration to 60 ppmv @ 0% O<sub>2</sub> on a 365 day rolling average. These limits will apply to the existing refinery fuel gas system, which supplies fuel to new and existing heaters. An 80 ppmv H<sub>2</sub>S limit on a 24 hr rolling average is also proposed to ensure the ambient impact of the SO<sub>2</sub> emissions remains below significance levels. This will establish additional limitations on existing heaters which have not been modified since there is a common fuel gas

supply for the refinery. KDHE agrees with this analysis, and proposes these limits on the fuel gas a BACT for SO<sub>2</sub> from the process heaters.

### **PM/PM<sub>10</sub> BACT for the Process Heaters**

Three different particulate matter control techniques were evaluated:

- 1) Gaseous Fuel limitations: Use of natural gas only.
- 2) Add-on Controls: Use of fabric filters and electrostatic precipitators to control PM/PM<sub>10</sub> emissions.
- 3) Workplace Standards: Use of low sulfur refinery gas and good combustion.

The use of 100% natural gas was determined to be technically unfeasible as a control option. This option would create an excess of refinery fuel gas. The excess refinery fuel gas would have to be disposed of by flaring, which would result in the PM/PM<sub>10</sub> emissions being transferred from the heaters to the flare.

The use of fabric filters or electrostatic precipitators are theoretically feasible for the control of particulate matter from process heaters utilizing refinery fuel gas. The fine particle size and low emission rates of particulate matter for these units are considered to make these options technically unfeasible for the process heaters.

The use of low sulfur refinery gas combined with good combustion practice in the workplace is considered to be BACT for the process heaters. NCRA has proposed meeting a particulate emission rate of 0.008 lb PM<sub>10</sub>/MMBtu as BACT for the process heaters. The No. 2 hydrogen plant heater burns a significant amount of purge gas from the Pressure Swing Adsorption (PSA) Unit. Due to the different composition of fuel in this unit, NCRA has proposed a BACT of 0.011 lb PM<sub>10</sub>/MMBtu for the No. 2 Hydrogen Plant Heater, based on vander guarantees. KDHE agrees with this analysis and the proposed BACT limits.

### **SO<sub>2</sub> and PM/PM<sub>10</sub> BACT for the Main Plant Flares A and B**

Emissions of SO<sub>2</sub> can be controlled by limiting sulfur content in the purge gas to the flares. Particulate emissions can be minimized through flare design and combustion controls. Add on controls are not technically feasible for this type of flare.

NCRA is proposing to design the flares to comply with the requirements of the New Source Performance Standards Subpart A, Section 60.18 and API Recommended Practice 520 and 521. The flares will be continuously monitored with an infrared sensor to insure the presence of a pilot flame, will at all times have a refinery gas/natural gas purge to maintain a

minimum heating value of 300 BTU/scf, and will be equipped with steam-assisted mixing at the flare tip. KDHE agrees with this analysis, and accepts the proposed workplace and design standards as BACT for Main Plant Flares A and B.

### **SO<sub>2</sub> and PM/PM<sub>10</sub> BACT for the Delayed Coker Unit Steam Vents**

The Delayed Coker Units are equipped with a closed blowdown system designed to minimize emissions and maximize recovery of the waste hydrocarbon and water streams generated during the off line process steps of the coke cycle and during coke drum relief events. During the final stages of the coke drum cycle, water is circulated through the vessel to cool the coke. There is enough heat in the coke during the initial stages of this cool down to flash off the water as low pressure steam less than 5 psig. This venting of low pressure steam will have a typical duration of approximately one hour per day.

No controls can be applied effectively to this vent stream due to the high moisture content, high exhaust velocities, and intermittent operation. NCRA proposes that BACT for this stream be work practice which minimizes the amount of material that is vented from the coker drum, consistent with safe and reliable operation. These operating procedures will include standards which require that vent be recovered to the fuel gas system until the pressure in the coker unit is less than 5 psig. KDHE agrees with this analysis and the proposed BACT limits.

### **PM/PM<sub>10</sub> BACT for the Petroleum Coke Handling System**

An enclosed handling system with a fabric filter is the preferred particulate control device for locations downstream of the coke crusher. Prior to the crushing unit, the large size and high moisture content of the petroleum coke provide effective particle control. NCRA proposed a BACT PM/PM<sub>10</sub> emission limit of 0.005 grains per dry standard cubic foot for the Coke Transfer Shed Baghouse and the Coke Load-Out Silo Baghouse, which control coke handling emissions downstream of the crusher. BACT for the coke handling operations upstream of the crusher is proposed to be a workplace standard requiring coke moisture content to be maintained at a level that ensures no visible emissions occur from these operations. KDHE agrees with this analysis and the proposed BACT limits.

### **SO<sub>2</sub> BACT for the Sulfur Recovery Plant**

The new Claus sulfur recovery plant, #3 SRU, will vent to the two existing ammonium thiosulfate (ATS) units for tail gas treatment. The ATS units utilize dual SO<sub>2</sub> absorption towers in series for control of SO<sub>2</sub> emissions. The ATS units vent through a common stack which includes a Continuous Emission Monitoring System (CEMS) for SO<sub>2</sub> concentrations. The SO<sub>2</sub> absorbers are followed by high efficiency mist eliminators, which provide additional particulate

and SO<sub>2</sub> control. NCRA is proposing a 90 ppmvd SO<sub>2</sub> @ 0% O<sub>2</sub> (24 hour rolling average) as a BACT for SO<sub>2</sub> for the SRU. KDHE agrees with this analysis and the proposed BACT limit.

### **PM/PM<sub>10</sub> BACT for the Sulfur Recovery Plant**

High efficiency mist eliminators are utilized as PM/PM<sub>10</sub> control on the refinery ATS units. This control technology is proposed as the basis for the BACT limit for the ATS units at the McPherson refinery. NCRA is proposing to establish a numerical BACT limit for PM/PM<sub>10</sub> from the stack for the ATS units based on source testing. In the interim period prior to receiving the source test data, a PM/PM<sub>10</sub> limit not to exceed 3.67 lb/hr PM / 7.76 lb/hr PM<sub>10</sub> is proposed as BACT. KDHE agrees with this analysis and the proposed BACT limit.

## Notice Concerning Proposed Kansas Air Quality Construction Permit and Public Hearing

Notice is hereby given that the Kansas Department of Health and Environment (KDHE) is soliciting comments regarding a proposed air quality construction permit. National Cooperative Refinery Association (NCRA) has applied for an air quality construction permit in accordance with the provisions of K.A.R. 28-19-300 to construct a heavy crude expansion project at their refinery located in McPherson, Kansas. Emission of particulate matter (PM), PM equal to or less than 10 microns in diameter (PM<sub>10</sub>), and sulfur oxides (SO<sub>x</sub>) were evaluated during the permit review process.

The proposed permit is to be issued in accordance with the provisions of K.A.R. 28-19-350, *Prevention of Significant Deterioration* (PSD) which adopt the federal standards, procedures and requirements of 40 CFR 52.21 by reference. These air quality regulations apply to major stationary emission sources located in areas designated as “attainment” under the federal Clean Air Act (CAA). Attainment areas are areas where the air quality meets or is better than the national ambient air quality standards (NAAQS).

The PSD regulations require evaluation of emission reduction techniques to identify the best available control technology (BACT) for each pollutant for which the emission rate exceeds the PSD significant level. The purpose of BACT is to affect the maximum degree of reduction achievable, taking into account energy, environmental and economic impacts for each pollutant under review. Evaluation of the estimated emissions for the proposed heavy crude expansion project indicates that the emission rate of sulfur dioxide and particulate matter exceed the significance levels. NCRA conducted the required BACT analyses. The department has reviewed NCRA’s BACT analyses and concurs with its findings that good combustion practices, use of low sulfur refinery fuel gas, and various good operating practices is the BACT for the heavy crude expansion project.

An ambient impact analysis was performed on the air emissions of PM<sub>10</sub> and SO<sub>x</sub> from the heavy crude expansion project. The analysis demonstrated no significant impact on ambient air quality for PM<sub>10</sub> and SO<sub>x</sub>.

An analysis of visibility for the Harvey County Park showed visibility impact criteria for federal class I areas were met at the nearby park. No adverse impacts on soils and vegetation in the area were expected. Any federal land manager who has reason to believe they may have a class I area adversely impacted by the emissions from the proposed project has the opportunity to present KDHE with a demonstration of the adverse impact on the air quality-related values of the federal class I area during the comment period.

A public comment period has been established to allow citizens the opportunity to express any concerns they may have about this proposed permitting action. The public comment period is to begin on July 10, 2008 and end on August 11, 2008. Written comments should be submitted to Dana S. Morris, Bureau of Air and Radiation, 1000 SW Jackson, Suite 310, Topeka, KS 66612-1366.

Any member of the public may request to hold a public hearing to receive comments on the proposed issuance of the draft air quality construction permit. Written request to hold a public hearing should be sent to the attention of Ms. Christy Thurman at the address listed above or by FAX to (785)291-3953 and must be received by noon on Monday, August 11, 2008. If a request is received, a public hearing is tentatively scheduled at 122 W. Marlin, 5<sup>th</sup> floor conference room, McPherson, KS 67460 on Tuesday, August 19, 2008 at 7:00 p.m. **If no requests to hold the public hearing are received by August 11, 2008, the public hearing will be cancelled. A notice of the cancellation will be posted at the KDHE website at [http://www.kdheks.gov/bar/public\\_notice.html](http://www.kdheks.gov/bar/public_notice.html).**

A copy of the proposed permit, permit application, all supporting documentation, and all information relied upon during the permit application review process are available for public review for a period of 30 days from the date of publication during normal business hours (8:00 AM to 5:00 PM) at the KDHE, Bureau of Air and Radiation (BAR), 1000 SW Jackson, Suite 310, Topeka, KS 66612-1366. Also a copy of the proposed permit only can be reviewed, at the KDHE North Central District Office, 2501 Market Place, Suite D, Salina, Kansas 67401. To obtain or review the proposed permit and supporting documentation, contact Dana Morris, (785)296-1578 at the central office of the KDHE and to review the proposed permit only, contact the Air Quality District Representative at (785)827-9639 in the KDHE North Central District Office. The standard departmental cost will be assessed for any copies requested.

Roderick L. Bremby, Secretary  
Kansas Department of Health and Environment