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November 5, 2012

Patrick B. Kimmet  
Refinery Manager  
CHS Inc.  
P.O. Box 909  
Laurel, MT 59044

Dear Mr. Kimmet:

Montana Air Quality Permit #1821-27 is deemed final as of November 1, 2012, by the Department of Environmental Quality (Department). This permit is for CHS, Inc – Laurel Refinery. All conditions of the Department's Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

For the Department,

Julie Merkel  
Air Permitting Supervisor  
Air Resources Management Bureau  
(406) 444-3626

Jenny O'Mara  
Environmental Engineer  
Air Resources Management Bureau  
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JM:JO  
Enclosures

Montana Department of Environmental Quality  
Permitting and Compliance Division

Montana Air Quality Permit #1821-27

CHS Inc.  
Laurel Refinery  
P.O. Box 909  
Laurel, MT 59044-0909

November 1, 2012



## Montana Air Quality Permit

Issued to: CHS Inc.  
Laurel Refinery  
P.O. Box 909  
Laurel, MT 59044-0909

MAQP: #1821-27  
Application Complete: July 12, 2012  
Preliminary Determination Issued: August 21, 2012  
Department Decision Issued: October 16, 2012  
Permit Final: November 1, 2012  
AFS #: 111-0012

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to CHS Inc. (CHS) pursuant to Sections 75-2-204, 211, and 215, Montana Code Annotated (MCA), as amended, and the Administrative Rules of Montana (ARM) 17.8.740, *et seq.*, as amended, for the following:

### Section I: Permitted Facilities

#### A. Plant Location/Description

CHS operates the Laurel petroleum refinery, located in the South ½ of Section 16, Township 2 South, Range 24 East, in Yellowstone County, Montana. The facility includes, but is not limited to, the following permitted equipment, by section:

- Section II. Plant-Wide Requirements (including Plant-wide Applicability Limits (PALs)). The refinery flare is not included under the PAL.
- Section III. Fuel Gas & Fuel Oil Combustion Devices
- Section IV. Hydrodesulfurization (HDS) complex with associated Zone D sulfur recovery unit (SRU) and tail gas treatment unit (TGTU)
- Section V. Boiler #10
- Section VI. Truck Loading Rack(s) and Vapor Combustion Unit(s) (VCU)
- Section VII. No. 1 Crude Unit
- Section VIII. Ultra Low Sulfur Diesel (ULSD) Unit and Hydrogen Plant
- Section IX. TGTU for Zone A's SRU #1 and SRU #2 trains
- Section X. Fluidized Catalytic Cracking Unit (FCCU)
- Section XI. Naphtha Hydrotreater (NHT) Unit, Delayed Coker Unit, and Zone E SRU/TGTU and Tail Gas Incinerator (TGI)
- Section XII. Boiler #11
- Section XIII. Railcar Light Product Loading Rack and VCU
- Section XIV. Boiler #12
- Section XV. Benzene Reduction Unit
- Section XVI. Product Storage Tanks

## Section XVII. Product Storage Tank 133

## Section XVIII. Wastewater Facilities

### B. Current Permit Action

On June 4, 2012, CHS Inc. submitted a permit application to the Department of Environmental Quality-Air Resources Management Bureau (Department) to modify MAQP # 1821-26 and Title V Operating Permit (OP) #OP1821-10. The application is for modification to two previously permitted refinery projects, and to construct a new gasoline and diesel truck loading facility as summarized below:

Mild Hydrocracker (MHC) Project Update. This application incorporates the final design and location of the Fluid Catalytic Cracking (FCC) Charge Heater being replaced as part of the MHC Project. The FCC Charge Heater was originally approved at 60 million british thermal units per hour (MMBtu/hr) as part of the MHC project (MAQP #1821-23). This permit application modifies the size of the heater from 60 to 66 MMBtu/hr. In addition, the permit application reclassifies the FCCU Reactor/Regenerator as a “modified” emitting unit rather than an “affected unit,” and CHS requests to replace the existing Riser with a new Riser (and Riser design) as the current Riser is nearing the end of its mechanical life.

Benzene Reduction Unit (BRU) Project Update. This project involves modification of the H-1001 Reformer Heater to achieve the design hydrogen production rate within the 1000 Unit Hydrogen Plant. Expansion of the 1000 Unit Hydrogen Plant was included in the MAQP #1821-18. However, the 1000 Unit Hydrogen Plant expansion changed the characteristics of the PSA tailgas (e.g. the heat content (British thermal units per standard cubic feet (Btu/scf) declined and the volume produced increased (standard cubic feet per minute (scfm)). According to CHS, the total heat input associated with the PSA tailgas remained nearly the same. As a result, the existing PSA tailgas burners on the H-1001 Reformer Heater could not handle the increased volume of PSA tailgas without excessive pressure drop and the 1000 Unit Hydrogen Plant production rate became limited by the volume of PSA tailgas that could be combusted. The proposed permit modification is to replace the PSA tailgas burner tips with tips that have larger ports such that all of the PSA tailgas that is generated can be combusted in H-1001. CHS is proposing to replace the supplemental fuel (e.g. natural gas, refinery fuel gas) burners in H-1001 to achieve improved NO<sub>x</sub> emission performance. The current heater is physically capable of combusting refinery fuel gas but cannot meet the existing oxides of nitrogen (NO<sub>x</sub>) permit limits while doing so. Additionally, the modified heater will have a higher maximum design firing rate (191.8 MMBtu-HHV/hr post project versus 177.7 MMBtu-HHV/hr) and a slight increase in the actual firing rate is also expected.

Gasoline and Distillate Truck Loading Facilities Project. This permit application also proposes the construction of new gasoline and distillate truck loading facilities, including new storage tanks, loading rack and VCU. The goal of the project is to improve safety and reduce truck congestion by relocating the gasoline and distillate truck loading operation to the east side of Highway 212. The existing truck loading rack and associated equipment will be permanently removed from service within 180 days of startup of the new loading facility. The permit modification also adds a new propane storage and loading facility to and permanently removes from service the existing propane loading facility.

In addition to those items mentioned above, this permit action also includes miscellaneous updates and amendments. CHS requested to discontinue use of the sulfur dioxide (SO<sub>2</sub>) Continuous Emissions Monitoring System (CEMs) on the H-1001 stack

because H-1001 is subject to 40 Code of Federal Regulations (CFR) 60, Subpart Ja which includes exemptions from hydrogen sulfide/sulfur dioxide (H<sub>2</sub>S/SO<sub>2</sub>) monitoring requirements for fuel gas streams that are inherently low in sulfur content. The primary fuel to H-1001, PSA tailgas is inherently low in sulfur content. CHS already monitors the H<sub>2</sub>S content of the refinery fuel gas (RFG) to be combusted in H-1001 as supplemental fuel, which would meet the monitoring requirements of Subpart Ja.

CHS requested that the Department remove condition IV.E.4 which requires the use of statistically significant F-factor values in determining compliance with NO<sub>x</sub> and carbon monoxide (CO) limits for the H-102 Reformer Heater. Rather, CHS proposes that results of the required performance testing be used to calculate an appropriate emission factor to demonstrate ongoing compliance with NO<sub>x</sub> and CO limits.

Section II: Plant-wide Refinery Limitations and Conditions (the refinery flare is not included).

A. National Emission Standards for Hazardous Air Pollutants

CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements as required by 40 CFR 61, Subpart FF- National Emissions Standards for Benzene Waste Operations (ARM 17.8.341 and 40 CFR 61, Subpart FF).

B. Annual Plant-wide Emission Limitations (ARM 17.8.749):

1. SO<sub>2</sub> emissions shall not exceed 2,980.3 tons per year (TPY)
2. NO<sub>x</sub> emissions shall not exceed 999.4 TPY
3. CO emissions shall not exceed 678.2 TPY
4. Volatile organic compounds (VOC) emissions shall not exceed 1,967.5 TPY
5. Particulate matter with an aerodynamic diameter of 10 microns or less (PM<sub>10</sub>) emissions shall not exceed 152.2 TPY
6. Particulate matter (PM) emissions shall not exceed 162.2 TPY

C. Compliance Determination (ARM 17.8.749):

CHS shall determine the CO, NO<sub>x</sub>, and VOC emissions for combustion sources by utilizing the Plant Information (PI) system information and normalize that PI system information to the refinery yield report. CHS shall also provide the Department with the amount of fuel consumed annually in the refinery as documented in the refinery yield report. This methodology was used to determine the CO, NO<sub>x</sub>, and VOC emissions in CHS's MAQP #1821-05 application and again in the August 12, 2004, letter from CHS to the Department.

CHS will track compliance with the emission caps based on source type, pollutant, calculation basis (emission factors, estimated yield and conversion), and key parameters (fuel oil use, fuel gas use, process gas use, and CEMS data). The units included in each source type are listed in Section I.A of the permit analysis. The calculation basis for each unit is listed in Attachment A (Plant-Wide Refinery Limitations and Conditions Compliance Determination).

The annual plant-wide emission limitations were established using specific calculation methods for each source. If an improved calculation methodology is identified and approved by the Department, the emission limitation for that pollutant(s) shall be reviewed and updated, if needed, before the new calculation method is utilized.

D. Reporting and Recordkeeping Requirements (ARM 17.8.749):

CHS shall provide quarterly emission reports to demonstrate compliance with Section II.B using data required in Section II.C. The quarterly report shall also include CEMS monitoring downtime that occurred during the reporting period.

E. Testing Requirements

1. Fuel flow rates, fuel heating value, production information and other data, as needed, shall be recorded during the performance of source tests in order to develop emission factors for use in the compliance determinations (ARM 17.8.749).
2. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).
3. The Department may require further testing (ARM 17.8.105).

F. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749):

1. CHS shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis and sources identified in Section I of this permit.

Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units as required by the Department. This information may be used for calculating operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. All records compiled in accordance with this permit must be maintained by CHS as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, EPA, and the Yellowstone County Air Pollution Control Agency, and must be submitted to the Department upon request (ARM 17.8.749).
3. CHS shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include a change of control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

G. Notification Requirements

CHS shall provide the Department (both the Billings regional and the Helena offices) with written notification of the following dates within the following time periods (ARM 17.8.749 and 340):

1. All compliance source tests as required by the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).
2. The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours (ARM 17.8.110).

Section III: Limitations and Conditions for Fuel Gas and Fuel Oil Combustion Devices

A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS). The following subparts, at a minimum, are applicable:

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
2. Subpart J - Standards of Performance for Petroleum Refineries applies to all fuel gas combustion devices. Applicability of NSPS Subpart Ja to fuel gas combustion devices is identified on a source by source basis within the permit (CHS Consent Decree Paragraphs 55 and 57).
3. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.

B. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 (2)).

C. Limitations on Fuel Gas and Fuel Oil Combustion Devices

1. SO<sub>2</sub> emissions from the combustion of alkylation unit polymer is limited to 50 tons per rolling 365-day time period (ARM 17.8.749). Periods of natural gas curtailment are not exempt from this limit.
2. Fuel oil combustion in refinery boilers is prohibited (ARM 17.8.749).
3. For fuel gas and fuel oil combustion devices where construction, reconstruction, or modification commenced prior to May 14, 2007, refinery fuel gas burned in fuel combustion devices shall not exceed 0.10 grains of H<sub>2</sub>S per dry standard cubic foot (162 parts per million, volumetric dry (ppm<sub>vd</sub>) H<sub>2</sub>S) per rolling 3-hour average (ARM 17.8.340, ARM 17.8.749, 40 CFR 60, Subpart J).
4. Refinery fuel gas burned in fuel combustion devices shall not exceed 0.05 grains of H<sub>2</sub>S per dry standard cubic foot (81 ppm<sub>vd</sub> H<sub>2</sub>S) per 12-month average (ARM 17.8.340 and ARM 17.8.749).

5. The burning of old sour water stripper overhead (SWSOH) in any fuel gas combustion device is prohibited (CHS Consent Decree Paragraphs 43 and 50 and Appendix A).
6. By December 31, 2011, CHS shall cease operation of Boilers #4 and #5 (CHS Consent Decree).
7. For fuel gas combustion devices where construction, reconstruction, or modification commenced after May 14, 2007, CHS shall not burn any fuel gas that contains H<sub>2</sub>S in excess of 162 ppm<sub>v,d</sub> determined hourly on a 3-hour rolling average basis and H<sub>2</sub>S in excess of 60 ppm<sub>v,d</sub> determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Ja).

D. Monitoring Requirements

1. CHS shall install and operate the following CEMS/Continuous emission rate monitors (CERMS): Continuous concentration (dry basis) monitoring of H<sub>2</sub>S in refinery fuel gas burned in all refinery fuel gas combustion devices, with the exception of refinery fuel gas streams with approved Alternative Monitoring Plans (AMP) or AMPs under review.
2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subpart J, 60.100-108, Subpart Ja, 60.100a-108a and Appendix B, Performance Specification 7 and Appendix F (Quality Assurance/Quality Control) provisions.
3. H<sub>2</sub>S refinery fuel gas CEMS and fuel gas flow rate meters shall comply with all applicable requirements of the Billings/Laurel SO<sub>2</sub> State Implementation Plan (SIP) Emission Control Plan, including Exhibit A and Attachments, adopted by the Board of Environmental Review, June 12, 1998, and stipulated to by Cenex Harvest States Cooperative and its successor CHS.
4. Fuel oil metering and analysis specifications (SOP SIP Method C-1) shall comply with all applicable requirements of the Billings/Laurel SO<sub>2</sub> SIP Emission Control Plan, including Exhibit A and Attachments, adopted by the Board of Environmental Review, June 12, 1998, and stipulated to by Cenex Harvest States Cooperative and its successor CHS.
5. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.

E. Compliance Determinations

1. Compliance determinations for SO<sub>2</sub> and H<sub>2</sub>S limits for the fuel gas-fired units within the refinery shall be based upon CEMs data utilized for H<sub>2</sub>S, as required in Section III.D.1 and fuel firing rates, if these units are fired on refinery fuel gas. Firing these units solely on natural gas shall demonstrate compliance with the applicable SO<sub>2</sub> limits.

2. Compliance determinations for the SO<sub>2</sub> limit from the combustion of alkylation unit polymer and fuel oil in all combustion devices shall be based upon methodology required in the Billings-Laurel SO<sub>2</sub> SIP and Appendix G of the CHS Consent Decree.
3. In addition to the testing required in each section, compliance determinations for the emission limits applicable to the fuel gas and fuel oil combustion devices shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test, and/or available CEM data. Fuel flow rates, fuel heating value, production information and other data, as needed, shall be recorded for each emitting unit during the performance of the source tests in order to develop emission factors for use in the compliance determinations. New emission factors (subject to review and approval by the Department) shall become effective within 60 days after the completion of a source test. Firing these units solely on natural gas shall demonstrate compliance with the applicable VOC limits (ARM 17.8.749).

F. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

CHS shall submit quarterly emission reports to the Department. Emission reporting for SO<sub>2</sub> generated from the combustion of fuel oil and alkylation unit polymer shall consist of a daily 365-day rolling average (in TPY) for each calendar day. CHS shall submit the quarterly emission reports within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department.

The quarterly report shall also include the following:

1. Source or unit operating time during the reporting period (Alkylation Unit and boilers burning fuel oil) and 24-hour (daily) average concentration of H<sub>2</sub>S in the refinery fuel gas burned at the permitted facilities.
2. Monitoring downtime that occurred during the reporting period.
3. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section III.C.
4. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section III.C. (ARM 17.8.749).
5. Reasons for any emissions in excess of those specifically allowed in Section III.C. with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.
6. For those refinery fuel gas streams covered by AMPs, the report should identify instances where AMP conditions were not met.

Section IV: Limitations and Conditions for the HDS Complex (future Mild Hydrocracker)

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable:
  1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart J - Standards of Performance for Petroleum Refineries applies to the SRU Incinerator Stack (E-407 & INC-401), the Fractionator Feed Heater Stack (H-202), the Reactor Charge Heater Stack (H-201), and the Hydrogen Reformer Heater (H-101).
  3. Subpart Ja - Standards of Performance for Petroleum Refineries applies to the Hydrogen Reformer Heater (H-102), FCCU Regenerator, FCC Charge-Heater-NEW.
  4. Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006, applies to the HDS unit.
  5. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to the Mild Hydrocracker unit once constructed.
  6. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the HDS unit.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Source Categories (ARM 17.8.342):
1. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
  2. Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. This applies to the replacement C-201B Compressor installed in 2006.<sup>1</sup>
- C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the HDS complex (ARM 17.8.304 (2)).
- D. Limitations on Individual Sources
1. Zone D SRU Incinerator Stack (INC-401)
    - a. SO<sub>2</sub> emissions from the Zone D SRU incinerator stack shall not exceed (ARM 17.8.749):
      - i. 31.1 tons/rolling 12-calendar month total,
      - ii. 341.04 lb/day,

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<sup>1</sup> 40 CFR 63, Subpart ZZZZ will no longer be applicable after completion of the Mild Hydrocracker Project because the gas driven motor on the C-201B compressor will be converted to an electric driven motor.

- iii. 14.21 lb/hr, and
  - iv. 250 parts per million, volumetric dry (ppm<sub>vd</sub>), rolling 12-hour average corrected to 0% oxygen, on a dry basis.
- b. Until 180 days after the completion of the expansion of the Zone D SRU/TGTU included in MAQP #1821-23, CHS shall operate and maintain the TGTU on the Zone D SRU to limit SO<sub>2</sub> emissions from the Zone D SRU incinerator stack (INC-401) to no more than 125 ppm<sub>vd</sub> on a rolling 12-month average corrected to 0% oxygen on a dry basis (ARM 17.8.752).
  - c. Within 180 days of completion of the expansion of the Zone D SRU/TGTU included in MAQP #1821-23, CHS shall operate and maintain the TGTU on the Zone D SRU to limit SO<sub>2</sub> emissions from the Zone D SRU incinerator stack (INC-401) to no more than 113.2 ppm<sub>vd</sub> at 0% oxygen on a daily rolling 365 day average (ARM 17.8.749).
  - d. NO<sub>x</sub> emissions from the Zone D SRU incinerator stack shall not exceed (ARM 17.8.749):
    - i. 3.5 tons/rolling 12-calendar month total,
    - ii. 19.2 lb/day, and
    - iii. 0.8 lb/hr.
  - e. CHS shall not fire fuel oil in this unit (ARM 17.8.749).

2. Compressor Gas Engine Stack (C-201B)

As included in MAQP #1821-23, the gas driven motor on the existing hydrogen compressor C-201B will be replaced with an electric driven motor. Once the replacement occurs, the following conditions will no longer be applicable.

- a. NO<sub>x</sub> emissions from C-201B shall not exceed (ARM 17.8.749):
  - i. 30.43 tons/rolling 12-calendar month total
  - ii. 7.14 lb/hr
- b. CO emissions from C-201B shall not exceed (ARM 17.8.749):
  - i. 68.59 tons/rolling 12-calendar month total
  - ii. 6.40 lb/hr when firing natural gas
  - iii. 16.10 lb/hr when firing propane
- c. VOC emissions from C-201B shall not exceed 10.1 tons/rolling 12-calendar month total (ARM 17.8.749).
- d. CHS shall only combust natural gas or propane in C-201B (ARM 17.8.749).

- e. CHS will maintain and operate a CO catalyst on the C-201B compressor exhaust (ARM 17.8.749).

3. Reformer Heater Stack (H-101)

- a. SO<sub>2</sub> emissions from H-101 shall not exceed (ARM 17.8.749):
  - i. 1.68 tons/rolling 12-calendar month total
  - ii. 2.15 lb/hr
- b. NO<sub>x</sub> emissions from H-101 shall not exceed (ARM 17.8.749):
  - i. 27.16 tons/rolling 12-calendar month total
  - ii. 6.78 lb/hr
- c. CO emissions from H-101 shall not exceed (ARM 17.8.749):
  - i. 13.93 tons/rolling 12-calendar month total
  - ii. 4.51 lb/hr
- d. VOC emissions from H-101 shall not exceed 0.35 tons/rolling 12-calendar month total (ARM 17.8.749).
- e. CHS shall not combust fuel oil in this unit (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60, Subpart J).

4. Reformer Heater Stack (H-102)

- a. All available 100 Unit PSA tailgas shall be fired in the 100 Unit Hydrogen Plant reformer heaters, except during periods of startup, shutdown or process upset (ARM 17.8.752).
- b. CHS shall not burn in the H-102 Reformer Heater any fuel gas that contains H<sub>2</sub>S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja).
- c. NO<sub>x</sub> emissions from H-102 shall not exceed:
  - i. 40 ppmv (dry basis, corrected to 0 percent excess air) on a 24-hour rolling average basis (40 CFR 60, Subpart Ja)
  - ii. 2.6 lb/hr (ARM 17.8.752)
  - iii. 11.3 tons/rolling 12-calendar month total (ARM 17.8.749)
- d. CO emissions from H-102 shall not exceed:
  - i. 5.7 lb/hr (ARM 17.8.752)
  - ii. 25.1 tons/rolling 12-calendar month total (ARM 17.8.749)

- e. During periods of startup or shutdown, CO emissions from the H-102 Reformer Heater shall not exceed 11.5 lb/hr on a 24-hour rolling average (ARM 17.8.749).
- f. H-102 shall be fitted with ULNBs (ARM 17.8.752).
- g. CHS shall implement proper design and good combustion techniques to minimize CO, VOC, and PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions (ARM 17.8.752).

5. Reactor Charge Heater Stack (H-201)

- a. SO<sub>2</sub> emissions from H-201 shall not exceed (ARM 17.8.749):
  - i. 4.35 tons/rolling 12-calendar month total
  - ii. 1.99 lb/hr
- b. NO<sub>x</sub> emissions from H-201 shall not exceed (ARM 17.8.749):
  - i. 11.56 tons/rolling 12-calendar month total
  - ii. 2.90 lb/hr
- c. CO emissions from H-201 shall not exceed (ARM 17.8.749):
  - i. 8.92 tons/rolling 12-calendar month total
  - ii. 2.23 lb/hr
- d. VOC Emissions from H-201 shall not exceed 0.91 tons/rolling 12-calendar month total (ARM 17.8.749).
- e. CHS shall not fire fuel oil in this unit (ARM 17.8.749).

6. Fractionator Feed Heater Stack (H-202)

- a. SO<sub>2</sub> emissions from H-202 shall not exceed (ARM 17.8.749):
  - i. 3.14 tons/rolling 12 calendar-month total
  - ii. 1.43 lb/hr
- b. NO<sub>x</sub> emissions from H-202 shall not exceed (ARM 17.8.749):
  - i. 8.34 tons/rolling 12 calendar-month total
  - ii. 2.09 lb/hr
- c. CO emissions from H-202 shall not exceed (ARM 17.8.749):
  - i. 6.43 tons/rolling 12-calendar month total
  - ii. 1.61 lb/hr

- d. VOC emissions from H-202 shall not exceed 0.65 tons/rolling 12-calendar month total (ARM 17.8.749).
- e. CHS shall not fire fuel oil in this unit (ARM 17.8.749).

E. Monitoring Requirements

- 1. CHS shall install and operate the following CEMS/CERMS for the SRU Incinerator Stack (E-407/INC-401):
  - a. SO<sub>2</sub> (SO<sub>2</sub> SIP, 40 CFR 60 Subparts J and Ja)
  - b. O<sub>2</sub> (40 CFR 60, Subparts J and Ja)
  - c. Volumetric Flow Rate (SO<sub>2</sub> SIP)
- 2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, 60.100-108, Subparts Ja, 60.100a-60.108a, and Appendix B, Performance Specifications 2, 3, 6, and Appendix F; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).
- 3. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. Startup shall be considered to be when acid gas and SWS streams are first introduced into the sulfur recovery facility. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated (ARM 17.8.749).

F. Testing Requirements

- 1. The SRU Incinerator Stack (E-407 & INC-401) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for SO<sub>2</sub> and NO<sub>x</sub>, and the results submitted to the Department in order to demonstrate compliance with the SO<sub>2</sub> and NO<sub>x</sub> emission limits contained in Section IV.D.1.a, b and c (ARM 17.8.105 and ARM 17.8.749).
- 2. The Superior Clean Burn II 12 SGIB (C201-B) compressor engine shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub> and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO<sub>x</sub> and CO emission limits contained in Section IV.D.2.a and b (ARM 17.8.105 and ARM 17.8.749).
- 3. The Reformer Heater Stack (H-101) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub> and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section IV.D.3.b and c (ARM 17.8.105 and ARM 17.8.749).
- 4. The Reformer Heater Stack (H-102) shall be tested every two years, pursuant to 40 CFR 60.104a(i)(5) and 107a(c)(6), or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub> and CO, concurrently,

and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section IV.D.4.c and d (ARM 17.8.105 and ARM 17.8.749, 40 CFR 60, Subpart Ja).

5. The Reactor Charge Heater Stack (H-201) shall be tested every 2 years, or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub> and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO<sub>x</sub> and CO emission limits contained in Section IV.D.5.b and c (ARM 17.8.105 and ARM 17.8.749).
6. The Fractionator Feed Heater Stack (H-202) shall be tested every 2 years, or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub> and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO<sub>x</sub> and CO emission limits contained in Section IV.D.6.b and c (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations

1. In addition to the testing required in Section IV.F, compliance determinations for hourly, 24-hour, and annual SO<sub>2</sub> limits for the SRU Incinerator stack shall be based upon CEMS data utilized for SO<sub>2</sub> as required in Section IV.E.1.
2. Compliance with the opacity limitation listed in Section IV.C shall be determined using EPA Reference Method 9 testing by a qualified observer.

H. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for SO<sub>2</sub> from the emission rate monitor shall consist of a daily 24-hour average (ppm SO<sub>2</sub>, corrected to 0% oxygen (O<sub>2</sub>)) and a 24-hour total (lb/day) for each calendar day. CHS shall submit the monthly emission reports within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The quarterly report shall also include the following:

1. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.
2. Monitoring downtime that occurred during the reporting period.
3. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Sections IV.D.1 through 6.
4. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Sections IV.D.1 through 6 (ARM 17.8.749).
5. Reasons for any emissions in excess of those specifically allowed in Sections IV.D.1 through 6 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section V: Limitations and Conditions for Boiler #10

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60 for Boiler #10. The following subparts, at a minimum, are applicable (ARM 17.8.340):

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
  2. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.
  3. Subpart J - Standards of Performance for Petroleum Refineries. The requirements of this Subpart apply to Boiler #10.
  4. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the refinery fuel gas supply lines to Boiler #10.
- B. Emission Limitations for Boiler #10
1. Fuel oil burning is not allowed in this unit (ARM 17.8.340, ARM 17.8.749, and ARM 17.8.752).
  2. SO<sub>2</sub> emissions shall not exceed:
    - a. 60 ppmv H<sub>2</sub>S in refinery fuel gas, 365-day rolling average (ARM 17.8.752)
    - b. 4.14 tons/rolling 12-calendar month total (ARM 17.8.749)
    - c. 2.53 lb/hr (ARM 17.8.752)
  3. NO<sub>x</sub> emissions shall not exceed:
    - a. 0.03 pounds per million British thermal units – Higher Heating Value (lb/MMBtu-HHV), 365-day rolling average (ARM 17.8.752)
    - b. 13.13 tons/rolling 12-calendar month total (ARM 17.8.749)
    - c. 3.5 lb/hr (ARM 17.8.749)
  4. During periods of startup or shutdown, CO emissions shall not exceed 10.0 lb/hr, 24-hour rolling average (ARM 17.8.752). Otherwise, CO emissions shall not exceed:
    - a. 0.05 lb/MMBtu-HHV, 365-day rolling average (ARM 17.8.752)
    - b. 21.88 tons/rolling 12-calendar month total (ARM 17.8.749)
    - c. 5.0 lb/hr (ARM 17.8.749)
  5. VOC emissions shall not exceed 2.24 tons/rolling 12-calendar month total (ARM 17.8.752).
  6. Opacity shall not exceed 20%, averaged over any 6 consecutive minutes (ARM 17.8.304).
  7. Boiler #10 shall be fitted with ULNBs, flue gas recirculation (FGR) and steam injection to the flame zone (ARM 17.8.752), and have a minimum stack height of 75 feet above ground level (ARM 17.8.749).

C. Monitoring Requirements

1. CHS shall install, operate, and maintain a CEMS/CERMS on Boiler #10, to monitor and record the NO<sub>x</sub> and O<sub>2</sub> for demonstration of compliance with the limits in Sections V.B, for each day when the boiler is combusting fuel gas (40 CFR 60, Subpart Db).
2. Boiler #10's continuous NO<sub>x</sub> and O<sub>2</sub> concentration monitors shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts Db, Appendix B (Performance Specifications 2 and 3), and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.340, ARM 17.8.105 and ARM 17.8.749).
3. CHS shall install, operate, and maintain a CEMS/CERMS on Boiler #10, to monitor and record the CO for demonstration of compliance with the limits in V.B, for each day when the boiler is combusting fuel gas. The CO CEMS shall comply with all applicable provisions of 40 CFR 60, Appendix B (Performance Specification 4) and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.749).
4. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.
5. CHS shall install and operate a volumetric stack flow rate monitor on Boiler #10. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1 (ARM 17.8.749).

D. Testing Requirements

Boiler #10 shall be tested for NO<sub>x</sub>, CO, and VOC concurrently at a minimum of every 5 years or according to another testing/monitoring schedule as may be approved by the Department. Testing shall be conducted for both natural gas and refinery fuel gas (ARM 17.8.105 and ARM 17.8.106).

E. Compliance Determinations

1. Compliance with the opacity limitations shall be determined according to 40 CFR, Part 60, Appendix A, Method 9 Visual Determination of Opacity of Emissions from Stationary Sources (ARM 17.8.749).
2. With exception to the initial performance test period, compliance with the lb/MMBtu limit(s) will be demonstrated using statistically significant F-factor values. The factor will be updated on a regular basis using data from all valid fuel gas samples representative of the fuel gas burned in Boiler #10. The method of compliance demonstration involving F-factor statistical significance is subject to change upon agreement with the Department and CHS (40 CFR 60, Appendix A, Reference Method 19).
3. Compliance with the NO<sub>x</sub> lb/hr limit shall be determined using the NO<sub>x</sub> CEM and the volumetric stack flow rate monitor (ARM 17.8.749).

4. Compliance with the CO lb/hr limit in Section V.B shall be determined using the CO CEM and the volumetric stack flow rate monitor (ARM 17.8.749).
- F. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)
1. CHS shall submit quarterly emission reports to the Department within 30 days of the end of each calendar quarter. Copies of the quarterly emission reports, excess emissions, emission testing reports and other reports required by Sections V.D and V.F.1 shall be submitted to both the Billings regional office and the Helena office. Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by the Department (ARM 17.8.340). The quarterly report shall include the following:
    - a. SO<sub>2</sub> emission data from the refinery fuel gas system continuous H<sub>2</sub>S concentration monitor required by Section III. The SO<sub>2</sub> emission rates shall be reported for the following averaging periods:
      - i. Average lb/hr per calendar day
      - ii. Total lb per calendar day
      - iii. Total tons per month
    - b. NO<sub>x</sub> emission data from the CEMS, fuel gas flow rate meter, and emission factors developed from the most recent compliance source test. The NO<sub>x</sub> emission rates shall be reported for the following averaging periods:
      - i. Average lb/MMBtu per calendar day
      - ii. Total tons per month
      - iii. lb/MMBtu per rolling 30-day average
      - iv. lb/MMBtu per rolling 365-day average (this requirement applicable upon startup of Boiler #10 following installation of the ULNBs)
      - v. Daily average and maximum lb/hr (this requirement applicable upon startup of Boiler #10 following installation of the ULNBs)
    - c. Source or unit operating time during the reporting period and daily, monthly, and quarterly refinery fuel gas and natural gas consumption rates.
    - d. Monitoring downtime that occurred during the reporting period.
    - e. An excess emission summary, which shall include excess emissions (lb/hr) for each pollutant identified in Section V.B.
    - f. Reasons for any emissions in excess of those specifically allowed in Section V.B with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

2. CHS shall comply with the reporting and recordkeeping requirements in 40 CFR 60.7 and 40 CFR 60.49b.

G. Notification

CHS shall provide the Department (both the Billings regional office and the Helena office) with written notification of the actual installation of the ULNBs on Boiler #10 within 15 days after the actual installation date (ARM 17.8.340 and ARM 17.8.749).

Section VI: Limitations and Conditions for the Truck Loading Rack(s) and associated VCU(s)

A. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements of ARM 17.8.342, as specified in 40 CFR Part 63, NESHAP for Source Categories.

1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
2. Subpart CC - National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries.
3. The product loading rack and vapor combustion unit shall be operated and maintained as follows:
  - a. CHS's product loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from cargo tanks during gasoline product loading (ARM 17.8.342 and ARM 17.8.752).
  - b. CHS's collected vapors shall be routed to the VCU at all times. In the event the VCU is inoperable, CHS may continue to load distillates with a Reid vapor pressure of less than 27.6 kilopascals, provided the Department is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.749).
  - c. The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline cargo tank from exceeding 4,500 Pascals (Pa) (450 millimeters (mm) of water) during product loading. This level shall not be exceeded when measured by the procedures specified in the test methods and procedures in 40 CFR 60.503(d) (ARM 17.8.342).
  - d. No pressure-vacuum vent in the permitted terminal's vapor collection system shall begin to open at a system pressure less than 4,500 Pa (450 mm of water) (ARM 17.8.342).
  - e. The vapor collection system shall be designed to prevent any VOC vapors collected at one loading rack from passing to another loading rack (ARM 17.8.342).
  - f. Loadings of liquid products into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using the following procedures (ARM 17.8.342):

- i. CHS shall obtain annual vapor tightness documentation described in the test methods and procedures in 40 CFR 63.425(e) for each gasoline cargo tank that is to be loaded at the product loading rack.
  - ii. CHS shall require the cargo tank identification number to be recorded as each gasoline cargo tank is loaded at the terminal.
  - iii. CHS shall cross-check each tank identification number obtained during product loading with the file of tank vapor tightness documentation within 2 weeks after the corresponding cargo tank is loaded.
  - iv. CHS shall notify the owner or operator of each non-vapor-tight cargo tank loaded at the product loading rack within 3 weeks after the loading has occurred.
  - v. CHS shall take the necessary steps to ensure that any non-vapor-tight cargo tank will not be reloaded at the product loading rack until vapor tightness documentation for that cargo tank is obtained, which documents that:
    - aa. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e) to this permit.
    - bb. For each gasoline cargo tank failing the test requirements in 40 CFR 63.425(f) or (g), the gasoline cargo tank must either:
      - 1. Before the repair work is performed on the cargo tank, meet the test requirements in 40 CFR 63.425 (g) or (h), or
      - 2. After repair work is performed on the cargo tank before or during the tests in 40 CFR 63.425 (g) or (h), subsequently pass the annual certification test described in 40 CFR 63.425(e).
  - g. CHS shall ensure that loadings of gasoline cargo tanks at the product loading rack are made only into cargo tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system (ARM 17.8.342).
  - h. CHS shall ensure that the terminal's and the cargo tank's vapor recovery systems are connected during each loading of a gasoline cargo tank at the product loading rack (ARM 17.8.342).
  - i. The existing VCU stack shall be 35 feet above grade and the new VCU for the new truck loading rack shall at least 40 feet above grade (ARM 17.8.749).
- B. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements, as specified in 40 CFR Part 60, NSPS for Stationary Sources. The following subparts, at a minimum, are applicable (ARM 17.8.340):

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
2. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.
3. Subpart XX - Standards of Performance for Bulk Gasoline Terminals.

C. Emission Limitations

1. The total annual VOC emissions from the truck loading rack(s), VCU and associated equipment (which includes the existing and proposed new truck loading rack, existing and proposed VCU and all associated storage tanks (135-143 and Additive Tanks # 1-4), the propane loading rack, and any fugitives shall not exceed 39.23 TPY based on a rolling 12-calendar month total. This is total combined VOC emission limit for the units listed in this Section (VI) and Section XVI (ARM 17.8.749).
2. VCU Emission Limitations
  - a. The total VOC emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 milligrams per liter (mg/L) of gasoline loaded (ARM 17.8.342, 40 CFR 63, Subpart CC, and ARM 17.8.752).
  - b. The total CO emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.752).
  - c. The total NO<sub>x</sub> emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 4.0 mg/L of gasoline loaded (ARM 17.8.752).
  - d. CHS shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU any visible emissions that exhibit an opacity of 20% or greater over any 6 consecutive minutes (ARM 17.8.304(2)).

D. Monitoring Requirements

1. CHS shall perform the testing and monitoring procedures specified in 40 CFR §§63.425 and 63.427 of Subpart R, except §63.425(d) or §63.427(c) (ARM 17.8.342).
2. CHS shall install and continuously operate a thermocouple and an associated recorder, or an ultraviolet flame detector and relay system, which will render the loading rack inoperable if a flame is not present at the VCU, or any other equivalent device, to detect the presence of a flame (ARM 17.8.342 and ARM 17.8.752).
3. CHS shall monitor and maintain all pumps, shutoff valves, relief valves and other piping and valves associated with the gasoline loading rack as described in 40 CFR Parts 60.482-1 through 60.482-10 (ARM 17.8.340).

4. A monitoring and maintenance program, as described under 40 CFR 60, Subpart VVa, and meeting the requirements of 40 CFR 60, Subpart GGGa shall be instituted (ARM 17.8.749 and ARM 17.8.340).

E. Testing Requirements

1. CHS shall comply with all test methods and procedures as specified by Subpart R §63.425 (a) through (c), and §63.425 (e) through (h). This shall apply to, but not be limited to, the product loading rack, the vapor processing system, and all gasoline equipment located at the product loading rack.
2. The product loading rack VCU shall be tested for VOCs, and compliance demonstrated with the emission limitation contained in Section VI.C.1 and C.2 on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department. CHS shall perform the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).
3. The product loading rack VCU shall be tested for CO and NO<sub>x</sub>, concurrently, and compliance demonstrated with the CO and NO<sub>x</sub> emission limitations contained in Section VI.B.3.b and c, as required by the Department (ARM 17.8.105).

F. Operational and Emission Inventory Reporting Requirements

CHS shall supply the Department with the following reports, as required by 40 CFR Part 63 (ARM 17.8.342).

1. Subpart CC - CHS shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63.428 (b) and (c), (g)(1), and (h)(1) through (h)(3) of Subpart R.
2. Subpart CC - CHS shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63.655 of Subpart R.

G. Notification Requirements

1. CHS shall provide the Department with written notification (both the Billings regional office and the Helena office) of the following dates within the specified time periods (ARM 17.8.749):
  - a. Beginning actual construction of the new Truck Loading Rack and VCU within 30 days after actual construction has begun;
  - b. Actual start-up date of new Truck Loading Rack and VCU within 15 days after the actual start-up.
  - c. Permanent removal from service the existing truck loading rack and associated equipment within 180 days from the startup of the new loading rack and associated equipment.
  - d. Within 180 days from startup of the new loading rack(s) and associated equipment, CHS shall provide documentation demonstrating that the existing truck loading rack, existing propane loading rack and the existing VCU have all been rendered inoperable.

Section VII: Limitations and Conditions for the No. 1 Crude Unit

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60 for the No. 1 Crude Unit. The following subparts, at a minimum, are applicable (ARM 17.8.340):
1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
  2. Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006 applies to the No. 1 Crude Unit fugitive piping equipment in VOC service as appropriate.
  3. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to the No. 1 Crude Unit fugitive piping equipment in VOC service as appropriate.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
1. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
  2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (Refinery MACT I).
- C. Emission Control Requirements for No. 1 Crude Unit (ARM 17.8.752):
1. The No. 1 Crude Unit shall be maintained and operated as per the Leak Detection and Repair (LDAR) Program. The LDAR program would apply to new equipment in both HAP and non-HAP VOC service in the No. 1 Crude Unit. The LDAR program would not apply to existing equipment in non-HAP service undergoing retrofit measures.
  2. CHS shall monitor and maintain all pumps, shutoff valves, relief valves and other piping and valves associated (as defined above) with the No. 1 Crude Unit as described in 40 CFR 60.482-1 through 60.482-10. Records of monitoring and maintenance shall be maintained on site for a minimum of 2 years.
- D. Limitations for Equipment Associated with the #1 Crude Unit Revamp Project
- A monitoring and maintenance program, as described under 40 CFR Part 60 VVa, and meeting the requirements of 40 CFR Part 60 GGGa shall be instituted (ARM 17.8.340, ARM 17.8.752, 40 CFR 60, Subpart GGGa).
- E. Monitoring Requirements
- CHS shall monitor with the LDAR database the type and number of new fugitive VOC components added (ARM 17.8.749).

F. Operational and Emission Inventory Reporting Requirements

CHS shall comply with the recordkeeping and reporting requirements contained in 40 CFR 60, Subpart GGGa (ARM 17.8.340 and 40 CFR 60, Subpart GGGa).

Section VIII: Limitations and Conditions for the ULSD Unit (900 Unit) and Hydrogen Plant (1000 Unit)

A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
2. Subpart J - Standards of Performance for Petroleum Refineries applies to the two new ULSD Unit heaters (H-901 and H-902) and the Hydrogen Plant heater (H-1001).
3. Subpart Ja - Standards of Performance for Petroleum Refineries applies to the H-1001 Reformer Heater.
4. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the ULSD Unit and the Hydrogen Plant fugitive piping equipment in VOC service.
5. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the ULSD Unit and Hydrogen Plant process drains.

B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAP for Source Categories (ARM 17.8.342).

1. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
2. Subpart CC – NESHAP from Petroleum Refineries shall apply to, but not be limited to, Tank 96 when it is utilized in gasoline service.

C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the ULSD Unit and Hydrogen Plant (ARM 17.8.304 (2)).

D. Limitations on Individual Sources (ARM 17.8.752)

1. Reactor Charge Heater H-901
  - a. SO<sub>2</sub> emissions from H-901 shall not exceed (ARM 17.8.752):
    - i. 1.96 tons/rolling 12-calendar month total
    - ii. 0.90 lb/hr

- b. NO<sub>x</sub> emissions from H-901 shall not exceed (ARM 17.8.752):
    - i. 2.19 tons/rolling 12-calendar month total
    - ii. 0.50 lb/hr
  - c. CO emissions from H-901 shall not exceed (ARM 17.8.752):
    - i. 9.00 tons/rolling 12-calendar month total
    - ii. 2.05 lb/hr
  - d. VOC Emissions from H-901 shall not exceed 0.59 tons/rolling 12-calendar month total (ARM 17.8.752).
  - e. CHS shall not fire fuel oil in this unit (ARM 17.8.752 and ARM 17.8.749).
2. Fractionator Reboiler H-902
- a. SO<sub>2</sub> emissions from H-902 shall not exceed (ARM 17.8.752):
    - i. 3.95 tons/rolling 12-calendar month total
    - ii. 1.80 lb/hr
  - b. NO<sub>x</sub> emissions from H-902 shall not exceed (ARM 17.8.752):
    - i. 4.40 tons/rolling 12-calendar month total
    - ii. 1.00 lb/hr
  - c. CO emissions from H-902 shall not exceed (ARM 17.8.752):
    - i. 8.50 tons/rolling 12-calendar month total
    - ii. 1.94 lb/hr
  - d. VOC Emissions from H-902 shall not exceed 1.19 tons/rolling 12-calendar month total (ARM 17.8.752).
  - e. CHS shall not fire fuel oil in this unit (ARM 17.8.752 and ARM 17.8.749).
3. Reformer Heater H-1001
- a. The H-1001 Reformer Heater shall be equipped with an ULNB and the firing rate of the H-1001 Reformer Heater shall not exceed 191.84 MMBtu/hr-HHV based on rolling 30-day average (ARM 17.8.752).
  - b. All available 1000 Unit PSA purge gas (sulfur free) shall be fired in the H-1001 Reformer Heater except during periods of startup, shutdown, operational transition, or process upset (ARM 17.8.752).

- c. CHS shall not burn in the H-1001 Reformer Heater any fuel gas that contains H<sub>2</sub>S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja).
- d. NO<sub>x</sub> emissions from H-1001 shall not exceed:
  - i. 40 ppmv (dry basis, corrected to 0 percent excess air) based on a 30-day rolling average (40 CFR 60, Subpart Ja).
  - ii. 0.035 lb/MMBtu-HHV, or 29.4 tons per rolling 12-calendar month total (ARM 17.8.752) .
  - iii. 0.04 lb/MMBtu-HHV, or 7.7 lb/hr based on an hourly rolling 24-hour average (ARM 17.8.752).
- e. CO emissions from H-1001 shall not exceed (ARM 17.8.752):
  - i. 0.02 lb/MMBtu-HHV, or 16.8 tons per rolling 12-calendar month total based on a 365-day rolling average.
  - ii. 0.04 lb/MMBtu-HHV, or 7.7 lb/hr during periods of startup and shutdown, based on a 24-hour rolling average.
- f. CO, VOC and PM/PM<sub>10</sub> emissions shall be controlled by proper design and good combustion practices (ARM 17.8.752).
- g. CHS shall not fire fuel oil in this unit (ARM 17.8.752 and ARM 17.8.749).

E. Monitoring Requirements (ARM 17.8.340).

- 1. CHS shall install and operate the following (CEMS/CERMS) for H-1001:
  - a. NO<sub>x</sub>/O<sub>2</sub> (40 CFR 60, Subpart Ja)
  - b. CO (ARM 17.8.749 )
  - c. Volumetric flow rate monitor
- 2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subparts Ja, 60.100a-108a, and Appendix B, Performance Specifications 2, 3, 4 or 4A, and Appendix F. The required volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.
- 3. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.
- 4. Compliance with the emission limits in Section VIII.D.3.d and VIII.D.3.e shall be determined using the NO<sub>x</sub>/CO CEMs and the volumetric stack flow rate monitor (with appropriate moisture correction).

F. Testing Requirements

1. The Reactor Charge Heater (H-901) shall be tested every two years, or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub> and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO<sub>x</sub> and CO emission limits contained in Section VIII.D.1.b and c (ARM 17.8.105 and ARM 17.8.749).
2. The Fractionator Reboiler (H-902) shall be tested every 2 years, or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub> and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO<sub>x</sub> and CO emission limits contained in Section VIII. D.2.b and c (ARM 17.8.105 and ARM 17.8.749).
3. The Reformer Heater (H-1001) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub> and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO<sub>x</sub> and CO emission limits contained in Section VIII.D.3.d and e (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations (ARM 17.8.749)

1. In addition to stack testing required in Section VIII.F, compliance determinations for the NO<sub>x</sub> limit in Section VIII.D.3 for H-1001 shall also be based upon monitoring data as required in Section VIII.E.
2. Compliance with the opacity limitation listed in Section VIII.C shall be determined using EPA Reference Method 9 testing by a qualified observer.

H. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for NO<sub>x</sub> and CO from the emission monitors shall consist of a daily maximum 1-hour average (ppm) for each calendar day. CHS shall submit the quarterly emission reports within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The quarterly report shall also include the following:

1. The daily and monthly NO<sub>x</sub> averages in ppm, corrected to 0% O<sub>2</sub>.
2. Monitoring downtime that occurred during the reporting period.
3. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in VIII.D.1 through 3.
4. Compliance determinations for hourly, 30-day, and annual limits specifically allowed in Sections VIII.D.1 through VIII.D.3 (ARM 17.8.749).
5. Reasons for any emissions in excess of those specifically allowed in Section VIII.D.3 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

- Section IX: Limitations and Conditions for the TGTU for Zone A's SRU #1 and SRU #2 trains and Zone A's Sulfur Recovery Plants
- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):
1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
  2. Subpart J - Standards of Performance for Petroleum Refineries applies to Zone A's SRU #1 and #2 tail gas incinerator (SRU-AUX-4) stack.
  3. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the TGTU process drains as applicable.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAP for Source Categories (ARM 17.8.342).
1. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
  2. Subpart UUU – MACT Standard for Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. CHS shall comply with Subpart UUU by complying with 40 CFR Part 60, NSPS Subpart J.
- C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the TGTU (ARM 17.8.304 (2)).
- D. The Department determined, based on modeling provided by CHS, that the SRU-AUX-4 stack shall be maintained at a height no less than 132 feet.
- E. Limitations on Individual Sources
1. SO<sub>2</sub> emissions from the SRU-AUX-4 stack shall not exceed:
    - a. 250 ppm, rolling 12-hour average corrected to 0% oxygen, on a dry basis (Consent Decree paragraph 63 and ARM 17.8.749)
    - b. 200 ppm, rolling 12-month average corrected to 0% oxygen, on a dry basis
    - c. 40.66 tons/rolling 12-month total
    - d. 11.60 lb/hr
    - e. 278.40 lb/day
  2. CHS shall operate and maintain the TGTU on the Zone A SRU to limit SO<sub>2</sub> emissions from the Zone A SRU-AUX-4 stack to no more than 200 ppm on a rolling 12-month average corrected to 0% oxygen on a dry basis.

3. NO<sub>x</sub> emissions from the SRU-AUX-4 stack shall not exceed:
  - a. 4.8 tons/rolling 12-calendar month total
  - b. 1.09 lb/hr
4. CHS shall not fire fuel oil in this unit (ARM 17.8.749).

F. Monitoring Requirements

1. CHS shall install and operate the following CEMS/CERMS on the Zone A SRU-AUX-4 Stack (CHS Inc, Consent Decree):
  - a. SO<sub>2</sub> (40 CFR 60, Subpart J and Billings SO<sub>2</sub> SIP)
  - b. O<sub>2</sub> (40 CFR 60, Subpart J)
  - c. Volumetric Flow Rate (Billings SO<sub>2</sub> SIP)
2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, 60.100-108 and Appendix B, Performance Specifications 2, 3, 6, and Appendix F. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.
3. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.

G. Testing Requirements

The SRU-AUX-4 Stack shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department for SO<sub>2</sub>, and shall be tested on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub>. The results shall be submitted to the Department in order to demonstrate compliance with the SO<sub>2</sub> and NO<sub>x</sub> emission limits contained in Sections IX.E.1, 2, and 3 (ARM 17.8.105 and ARM 17.8.749).

H. Compliance Determinations (ARM 17.8.749)

1. In addition to the testing required in Section IX.G, compliance determinations for ppm concentration, hourly, 3-hour, 24-hour, rolling 12-month, and annual SO<sub>2</sub> limits for the SRU-AUX-4 Stack shall be based upon CEMS data utilized for SO<sub>2</sub> as required in Section IX.F.1.
2. Compliance with the opacity limitation listed in Section IX.C shall be determined using EPA reference method 9 testing by a qualified observer.

I. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

Emission reporting for SO<sub>2</sub> from the emission rate monitors shall consist of a daily 24-hour average concentration (ppm SO<sub>2</sub>, corrected to 0% O<sub>2</sub>) and a 24-hour total (lb/day) for each calendar day. CHS shall submit a quarterly emission report within 30 days of

the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The quarterly report shall also include the following:

1. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.
2. Monitoring downtime that occurred during the reporting period.
3. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section IX.E.
4. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section IX.E.
5. Reasons for any emissions in excess of those specifically allowed in Section IX.E with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section X: Limitations and Conditions for the FCCU and related units

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable:
  1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
  2. Subpart J - Standards of Performance for Petroleum Refineries applies to the FCCU Regenerator for SO<sub>2</sub>, CO, PM and opacity.
  3. Subpart Ja—Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (The FCCU Regenerator Stack is subject to NSPS Subpart Ja for CO only, and the new FCCU Charge Heater (FCC-Heater-NEW) is subject to the fuel gas combustion device requirements).
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
  1. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
  2. Subpart CC – Refinery MACT I shall apply to, but not be limited to, certain parts of the FCCU piping.
  3. Subpart UUU – Refinery MACT II shall apply to, but not be limited to, the FCCU.
- C. Opacity
  1. CHS shall not cause or authorize emissions to be discharged from the FCCU Regenerator Stack into the outdoor atmosphere that exhibit an opacity of 30% or greater averaged over 6 consecutive minutes (ARM 17.8.304, CHS Consent Decree Paragraph 55).

2. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from the FCC-Heater-1 installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304).
3. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

D. Limitations on Individual Emitting Units

1. FCCU Regenerator Stack
  - a. CO emissions from the FCCU Regenerator Stack shall not exceed 500 ppm at 0% O<sub>2</sub> per 1-hour time period (CHS Consent Decree Paragraph 41, ARM 17.8.340, 40 CFR Part 60, Subpart J; and ARM 17.8.752).
  - b. CO emissions from the FCCU Regenerator Stack shall not exceed 100 ppm<sub>vd</sub> at 0% O<sub>2</sub>, on a 365-day rolling average basis (CHS Consent Decree Paragraph 41).
  - c. CHS shall not exceed 50 ppm SO<sub>2</sub> by volume (corrected to 0% O<sub>2</sub>) on a 7-day rolling average and shall also comply with an SO<sub>2</sub> concentration limit of 25 ppm<sub>vd</sub> at 0% O<sub>2</sub> on a 365-day rolling average basis (CHS Consent Decree Paragraphs 32-33, and ARM 17.8.752).
  - d. PM emissions from the FCCU Regenerator Stack shall be controlled with an ESP. PM emissions from the FCCU Regenerator Stack shall not exceed 1.0 lb PM/1,000 lb of coke burned (CHS Consent Decree and ARM 17.8.752).
  - e. NO<sub>x</sub> emissions from the FCCU Regenerator Stack shall not exceed 65.1 ppm<sub>vd</sub> at 0% oxygen on a 365-day rolling average basis. This long-term limit shall apply at all times (including during startup, shutdown, malfunction, and hydrotreater outages) that the FCCU Regenerator Stack is operating (CHS Consent Decree Paragraph 29 and ARM 17.8.752).
  - f. NO<sub>x</sub> emissions from the FCCU Regenerator Stack shall not exceed 102 ppm<sub>vd</sub> at 0% oxygen on a 7-day rolling average basis. This short-term limit shall exclude periods of startup, shutdown, malfunction or hydrotreater outages, but shall apply at all other times that the FCCU is operating. For days and hours in which the FCCU Regenerator Stack is not operating, no NO<sub>x</sub> value shall be used in the average, and those periods shall be skipped in determining compliance with the 7-day and 365-day averages (CHS Consent Decree Paragraph 29 and ARM 17.8.752).
  - g. NO<sub>x</sub> emissions from the FCCU Regenerator Stack shall not exceed 117 tons per 12-month rolling average (limit is based on 65.1 ppm<sub>vd</sub> at 0% oxygen on a 365-day rolling average) (ARM 17.8.749).

- h. CO and VOC emissions from the FCCU Regenerator stack shall be controlled through the use of CO combustion promoters as needed, and good combustion practices. Compliance with the FCCU Regenerator Stack CO emission limits shall be used as a surrogate for VOCs (ARM 17.8.752).

2. FCC Charge Heater (FCC-Heater-1)

As included in MAQP #1821-23 and MAQP #1821-27, FCC-Heater-NEW will be installed to replace FCC-Heater-1. FCC-Heater-1 shall be shutdown and permanently removed from service as an emissions source within 180 days of the initial startup of FCC-Heater-NEW. The following conditions shall apply once FCC-Heater-NEW begins operation.

- a. The FCC Charge Heater (FCC-Heater-1) shall not exceed 49.7 MMBtu/hr on a rolling 12-calendar month basis (ARM 17.8.749).
- b. NO<sub>x</sub> emissions from the FCC Charge Heater (FCC-Heater-1) shall not exceed (ARM 17.8.749):
  - i. 22.87 tons/rolling 12-calendar month total
  - ii. 6.27 lb/hr
- c. CO emissions from the FCC Charge Heater (FCC-Heater-1) shall not exceed (ARM 17.8.749):
  - i. 19.21 tons/rolling 12-calendar month total
  - ii. 5.26 lb/hr

2a. FCC Charge Heater (FCC-Heater-NEW)

The FCC-Heater-NEW will be installed to replace FCC-Heater-1. FCC-Heater-1 shall be permanently removed from service within 180 days of initial startup of FCC-Heater-NEW and the following conditions shall apply:

- a. The FCC-Heater-NEW shall be equipped with an ULNB and the firing rate of the heater shall not exceed 66 MMBtu/hr-HHV based on a 30-day rolling hourly average (ARM 17.8.752).
- b. NO<sub>x</sub> emissions from FCC-Heater-NEW shall not exceed:
  - i. 40 ppmv (dry basis, corrected to 0 percent excess air) based on a 30-day rolling average (40 CFR 60, Subpart Ja and ARM 17.8.752)
  - ii. 0.035 lb/MMBtu-HHV, or 10.1 tpy based on a 12-calendar month total (ARM 17.8.752).
  - iii. 0.04 lb/MMBtu-HHV, or 2.6 lb/hr based on an hourly 24-hour rolling average (ARM 17.8.752).
- c. CO emissions from FCC-Heater-NEW shall not exceed 100 ppmv at 3% oxygen based on a 24-hour rolling average (ARM 17.8.752).

- d. CHS shall not combust any fuel gas that contains H<sub>2</sub>S in excess of 60 ppmv determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja).
- e. CHS shall implement proper design and good combustion techniques to minimize CO, VOC, and PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions (ARM 17.8.752).

E. Monitoring Requirements

1. CHS shall install and operate the following CEMS/CERMS on the FCCU Regenerator Stack (CHS Consent Decree):
  - a. CO
  - b. NO<sub>x</sub>
  - c. SO<sub>2</sub>
  - d. O<sub>2</sub>
  - e. Opacity (40 CFR 63, Subpart UUU)
2. CHS shall install and operate the following on the FCC-Heater-NEW:
  - a. NO<sub>x</sub>/O<sub>2</sub> CEMS
  - b. Volumetric flow rate monitor
3. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, 60.100-108, Subparts Ja, 60.100a-108a and Appendix B, Performance Specifications 1, 2, 3, 6, and Appendix F. The volumetric flow rate monitor(s) shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.
4. The FCCU and FCC-Heater-NEW CEMS, stack gas volumetric flow rate CEMS, and the fuel gas flow meters shall comply with all applicable requirements of the Billings/Laurel SO<sub>2</sub> SIP Emission Control Plan, including Exhibit A and Attachments, adopted by the Board of Environmental Review, June 12, 1998, and stipulated to by Cenex Harvest States Cooperative and its successor CHS.
5. Compliance with the emission limits in Section X.D.2aa and, X.D.2a.b shall be determined using the NO<sub>x</sub>/O<sub>2</sub> CEMs and the volumetric stack flow rate monitor (with appropriate moisture correction).
6. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.

F. Testing Requirements

1. CHS shall follow the stack protocol specified in 40 CFR 60.106(b)(2) to measure PM emissions from the FCCU Regenerator stack. CHS shall conduct the PM tests on an annual basis or on another testing schedule as may be approved by the Department (CHS Consent Decree Paragraph 38 and ARM 17.8.105).
2. The FCC Charge Heater (FCC-Heater-NEW) shall be initially within 180 days of startup and then tested annually thereafter, in conjunction with annual CEMS/CERMS RATA performance testing in accordance with Appendix F (40 CFR Part 60) requirements, or according to another testing/ monitoring schedule as may be approved by the Department, for NO<sub>x</sub>/O<sub>2</sub> and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO<sub>x</sub> and CO emission limits contained in Section X.D.2a.b and X.D.2a.c (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations

1. Compliance determinations for the FCCU Regenerator Stack emission limits in Section X.D for NO<sub>x</sub>, CO, and SO<sub>2</sub> shall be based upon monitor data, as required in Section X.E.1.
2. Compliance determinations for the FCC-Heater-NEW emission limits in Section X.D for NO<sub>x</sub> and CO shall be based upon monitor data, as required in Section X.E.2.
3. Compliance with the opacity limitations listed in Section X.C shall be determined using EPA reference method 9 observations by a qualified observer or a certified continuous opacity monitor system (COMS).

H. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

For the FCCU Regenerator Stack and the FCC-Heater-New, CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for SO<sub>2</sub> (applies to FCCU Regenerator Stack only), NO<sub>x</sub> and CO from the emission monitors shall consist of a daily maximum 1-hour average (ppm) for each calendar day. CHS shall submit the quarterly emission reports within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The quarterly report shall also include the following:

1. Source or unit operating time during the reporting period and the 7-day and 365-day rolling average SO<sub>2</sub> concentrations (ppmv).
2. The daily and monthly NO<sub>x</sub> averages in ppm, corrected to 0% O<sub>2</sub>.
3. Monitoring downtime that occurred during the reporting period.
4. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section X.D.1 and X.D.2a.
5. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section X.D.1 and X.D.2a (ARM 17.8.749).

6. Reasons for any emissions in excess of those specifically allowed in Section X.D with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

I. Notification Requirements (ARM 17.8.749)

1. CHS shall provide the Department (both the Billings regional office and the Helena office) with written notification of the actual start-up date of the FCC-Heater-NEW within 15 days after the actual start-up date (ARM 17.8.340 and ARM 17.8.749).
2. CHS shall provide the Department (both the Billings regional office and the Helena office) with written notification of the actual start-up date of the FCC Unit with the new Catalyst Riser within 15 days after the actual start-up date (ARM 17.8.340 and ARM 17.8.749).
3. Within 180 days from startup of the FCC-Heater-NEW, CHS shall provide documentation to the Department demonstrating that the existing FCC-Heater-1 has been permanently removed from service and has been rendered inoperable.

Section XI: Limitations and Conditions for the Naptha Hydrotreating Unit, Delayed Coker Unit and Zone E SRU/TGTU/TGI

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):
  1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
  2. Subpart J - Standards of Performance for Petroleum Refineries applies to the NHT Charge Heater (H-8301), the Coker Charge Heater (H-7501), and the Zone E SRU/TGTU/TGI.
  3. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the Naptha Hydrotreating Unit and the Delayed Coker Unit fugitive piping equipment in VOC service.
  4. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the Delayed Coker Unit process drains.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
  1. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
  2. Subpart CC – Refinery MACT I shall apply to, but not be limited to, affected sources or the collection of emission points as defined in this subpart.
  3. Subpart UUU – Refinery MACT II shall apply to, but not be limited to, the Zone E SRU/TGTU/TGI.

C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the Delayed Coker Unit (ARM 17.8.304 (2)).

D. Limitations on Individual Sources

1. NHT Charge Heater (H-8301)

- a. SO<sub>2</sub> emissions from the NHT Charge Heater (H-8301) shall not exceed (ARM 17.8.752):
  - i. 1.54 tons/rolling 12-calendar month total
  - ii. 0.70 lb/hr
- b. NO<sub>x</sub> emissions from the NHT Charge Heater (H-8301) shall not exceed (ARM 17.8.752):
  - i. 6.55 tons/rolling 12-calendar month total
  - ii. 1.50 lb/hr
- c. CO emissions from the NHT Charge Heater (H-8301) shall not exceed 400 ppm<sub>vd</sub> at 3% oxygen on a 30-day rolling average (ARM 17.8.752).
- d. VOC Emissions from the NHT Charge Heater (H-8301) shall not exceed 0.86 tons/rolling 12-calendar month total (ARM 17.8.752).
- e. CHS shall not fire fuel oil in this unit (ARM 17.8.340; 40 CFR 60, Subpart J; and ARM 17.8.752).

2. Coker Charge Heater (H-7501)

- a. SO<sub>2</sub> emissions from the Coker Charge Heater (H-7501) shall not exceed (ARM 17.8.752):
  - i. 6.61 tons/rolling 12-calendar month total
  - ii. 3.02 lb/hr
- b. NO<sub>x</sub> emissions from the Coker Charge Heater (H-7501) shall not exceed (ARM 17.8.752):
  - i. 28.2 tons/rolling 12-calendar month total
  - ii. 6.44 lb/hr
- c. CO emissions from the Coker Charge Heater (H-7501) shall not exceed (ARM 17.8.752):
  - i. 400 ppm<sub>vd</sub> at 3% oxygen on a 30-day rolling average
  - ii. 35.2 tons/rolling 12-calendar month total

- iii. 8.05 lb/hr
  - d. During periods of startup, shutdown, and spalling (a feed heater coil decoking process completed during operation to avoid complete unit shutdown), CO emissions from the Coker Charge Heater (H-7501) shall not exceed 16.1 lb/hr on a 24-hour rolling average (ARM 17.8.752).
  - e. VOC Emissions from the Coker Charge Heater (H-7501) shall not exceed 1.41 tons/rolling 12-calendar month total (ARM 17.8.752).
  - f. CHS shall not fire fuel oil in this unit (ARM 17.8.340; 40 CFR 60, Subpart J; and ARM 17.8.752).
3. The Coker unit flare shall operate with a continuous pilot flame and a continuous pilot flame-operating device and meet applicable control device requirements of 40 CFR Part 63.11 (40 CFR 63.11, ARM 17.8.752).
  4. VOC emissions from the Sour Water Storage Tank (TK-129) shall be controlled by the installation and use of an internal floating roof and a submerged fill pipe (ARM 17.8.752).
  5. VOC emissions from the Coker Sludge Storage Tank (TK-7504) shall be controlled by the installation and use of a fixed roof, a submerged fill pipe, and a conservation vent (ARM 17.8.752).
  6. Coke processing operations
    - a. CHS shall store onsite coke in the walled enclosure for coke storage only. Onsite coke storage shall be limited to a volume that is contained within the walled enclosure. Storage of coke outside of the walled enclosure is prohibited (ARM 17.8.752).
    - b. The coke pile shall not exceed the height of the enclosure walls adjacent to the pile at any time (ARM 17.8.752).
    - c. CHS shall not cause or authorize emissions to be discharged into the atmosphere from coke handling without taking reasonable precautions to control emissions of airborne particulate matter. CHS shall wet the coke as needed to comply with the reasonable precautions standard (ARM 17.8.308 and ARM 17.8.752).
    - d. CHS shall install and maintain enclosures surrounding the coke conveyors, coke transfer drop points (not including the location at which coke is transferred from the front-end loader to the initial coke sizing screen), and crusher (ARM 17.8.752).
    - e. CHS shall install and maintain a telescoping loading spout for loading coke into railcars (ARM 17.8.752).
    - f. Alternate Coke Handling Method: In the event the conveyors are inoperable (as described in Section XI.D.6.d and e) due to either planned or unplanned maintenance activities, CHS may transport uncrushed coke only from the coke storage area to the railcar using a front-end loader.

The requirements specified in Section XI.D.6.a – c still apply. The alternate coke handling method is limited to 24 batches per year (ARM 17.8.752).

7. Zone E SRU/TGTU/TGI

- a. SO<sub>2</sub> emissions from the Zone E SRU/TGTU/TGI shall not exceed (ARM 17.8.752):
  - i. 49.4 tons/rolling 12-calendar month total (based on 200 ppm, rolling 12-month average corrected to 0% oxygen, on a dry basis)
  - ii. 14.1 lb/hr (based on 250 ppm, rolling 12-hour rolling average corrected to 0% oxygen, on a dry basis)
- b. CHS shall operate and maintain the TGTU on the Coker Unit to limit SO<sub>2</sub> emissions from the Coker Unit stack to no more than 200 ppm on a rolling 12-month average corrected to 0% oxygen on a dry basis.
- c. NO<sub>x</sub> emissions from the Zone E SRU/TGTU/TGI shall not exceed (ARM 17.8.749):
  - i. 4.62 tons/rolling 12-calendar month total
  - ii. 1.05 lb/hr
- d. CHS shall not cause or authorize to be discharged into the atmosphere from the TGI:
  - i. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.752)
  - ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO<sub>2</sub> (ARM 17.8.752)

8. CHS is required to operate and maintain a mist eliminator on the Coker Cooling Tower that limits PM<sub>10</sub> emissions to no more than 0.002% of circulating water flow (ARM 17.8.752).

9. Coke Drum Steam Vent

- a. While operating the delayed coking unit, CHS shall depressurize to 5 lb per square inch gauge (psig) during reactor vessel depressurizing and vent the exhaust gases to the fuel gas recovery system for combustion in a fuel gas combustion device. The vessel shall not be opened to atmosphere until the pressure is 5.0 psig or lower. (ARM 17.8.749).
- b. VOC emissions from the Coke Drum Steam Vent shall not exceed 18.10 tons/yr as determined on a monthly rolling 12-month average (ARM 17.8.749).
- c. PM<sub>10</sub> emissions from the Coke Drum Steam Vent shall not exceed 4.52 tons/yr as determined on a monthly rolling 12-month average (ARM 17.8.749).

E. Monitoring requirements

1. CHS shall install and operate the following (CEMS/CERMS):

Zone E SRU/TGTU/TGI (Billings/Laurel SO<sub>2</sub> SIP)

- i. SO<sub>2</sub> (40 CFR 60, Subpart J)
  - ii. O<sub>2</sub> (40 CFR 60, Subpart J)
  - iii. Volumetric Flow Rate (Billings/Laurel SO<sub>2</sub> SIP)
2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subpart Db 60.40b through 60.49b, Subparts J, 60.100-108, and Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.
  3. The Delayed Coker Unit SO<sub>2</sub> CEMS, stack gas volumetric flow rate CEMS, and fuel gas flow rate meters shall comply with all applicable requirements of the Billings/Laurel SO<sub>2</sub> SIP Emission Control Plan, including Exhibit A and Attachments, adopted by the Board of Environmental Review, June 12, 1998, and stipulated to by Cenex Harvest States Cooperative and its successor CHS.
  4. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.
  5. CHS shall continuously monitor the pressure in the coke drums such that the pressure at which each drum is depressurized can be determined (ARM 17.8.749).

F. Testing Requirements

1. The NHT Charge Heater (H-8301) shall be tested every 2 years, or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub> and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO<sub>x</sub> and CO emission limits contained in Section XI.D.1.b and c (ARM 17.8.105 and ARM 17.8.749).
2. The Coker Charge Heater (H-7501) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub> and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO<sub>x</sub> and CO emission limits contained in Section XI.D.2.b and c (ARM 17.8.105 and ARM 17.8.749).
3. The Zone E SRU/TGTU/TGI stack shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department for SO<sub>2</sub>, and shall be tested on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub>. The

results shall be submitted to the Department in order to demonstrate compliance with the SO<sub>2</sub> and NO<sub>x</sub> emission limits contained in Section XI.D.7.a, b, and c, respectively (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations (ARM 17.8.749).

1. In addition to the testing required in Section XI.F, compliance determinations for ppm concentration, hourly, and rolling 12-month SO<sub>2</sub> limits for the Zone E SRU/TGTU/TGI shall be based upon CEMS data utilized for SO<sub>2</sub> as required in Section XI.E.1 (ARM 17.8.749).
2. Compliance with the opacity limitation listed in Section XI.C shall be determined using EPA reference method 9 observations by a qualified observer or a certified COMS.
3. Using the following equations, CHS shall determine the VOC and PM<sub>10</sub> emissions from the Coke Drum Steam Vent each time a steam vent is opened to the atmosphere (cycle). CHS shall sum emissions from all cycles on a rolling 12-month basis to determine compliance with the emissions limits (ARM 17.8.749).

$$PM_{10}, lb / cycle = \left( \frac{15}{2} / \frac{65}{4} \right) \left( 1.5041P^2 + 17.603P + 3.7022 \right)$$

$$VOC, lb / cycle = \left( \frac{15}{2} / \frac{65}{4} \right) \left( 0.6378P^3 - 33.487P^2 + 144.5P - 37.706 \right)$$

*P = pressure (psig) at which each coke drum is depressurized.*

H. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

1. CHS shall prepare and submit a quarterly emission and coke handling report within 30 days of the end of each calendar quarter. Emission reporting for SO<sub>2</sub> from the emission rate monitors shall consist of a daily 24-hour average concentration (ppm SO<sub>2</sub>, corrected to 0% O<sub>2</sub>) and a 24-hour total (lb/day) for each calendar day. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The quarterly report shall also include the following:
  - a. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.
  - b. Monitoring downtime that occurred during the reporting period.
  - c. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in XI.D.1 through 2, 7 and 8.
  - d. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section XI.G.
  - e. Reasons for any emissions in excess of those specifically allowed in Section XI.D.1 through 2, 7 and 8 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

- f. A summary of the number of batches of coke that were processed using the alternative coke handling method (ARM 17.8.749).
2. For non-minor (defined in the June 12, 1998 Stipulation) flaring events, CHS shall comply with the reporting requirements identified in Section (3)(A)(5) of Exhibit A-1 of the Stipulation signed by the Board of Environmental Review on June 12, 1998 (ARM 17.8.749).
3. CHS shall include in the quarterly emissions report the VOC and PM<sub>10</sub> emissions as tons/rolling 12-month total and any instances that the drum is not depressurized at below 5 psig (ARM 17.8.749).

Section XII: Limitations and Conditions for Boiler #11

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):
  1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
  2. Subpart J - Standards of Performance for Petroleum Refineries applies to Boiler #11.
  3. Subpart Db – Standards of Performance for Steam Generating Units applies to Boiler #11.
- B. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in Boiler #11 (ARM 17.8.304 (2)).
- C. Limitations on Boiler #11
  1. SO<sub>2</sub> emissions from Boiler #11 shall not exceed (ARM 17.8.752):
    - a. 8.59 tons/rolling 12-calendar month total
    - b. 3.92 lb/hr
  2. NO<sub>x</sub> emissions from Boiler #11 shall not exceed (ARM 17.8.752):
    - a. 18.3 tons/rolling 12-calendar month total
    - b. 4.18 lb/hr
  3. During periods of startup or shutdown, CO emissions from Boiler #11 shall not exceed 23 lb/hr on a 24-hour rolling average (ARM 17.8.752). Otherwise, CO emissions shall not exceed (ARM 17.8.752):
    - a. 400 ppm<sub>vd</sub> at 3% oxygen on a 30-day rolling average
    - b. 36.63 tons/rolling 12-calendar month total
    - c. 15.26 lb/hr

4. VOC Emissions from the Boiler #11 shall not exceed 4.83 tons/rolling 12-calendar month total (ARM 17.8.752).
5. CHS shall not fire fuel oil in this unit (ARM 17.8.340; 40 CFR 60, Subpart J; and ARM 17.8.752).

D. Monitoring requirements

1. CHS shall install and operate the following (CEMS/CERMS) for Boiler #11:
  - a. NO<sub>x</sub> (40 CFR 60, Subpart Db)
  - b. O<sub>2</sub> (40 CFR 60, Subpart Db)
2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subpart Db; 60.40b through 60.49b, Subparts J; 60.100-108, and Appendix A, Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F.
3. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.
4. With exception to the initial performance test period, compliance with the lb/MMBtu limit(s) will be demonstrated using statistically significant F-factor values. The factor will be updated on a regular basis using data from all valid fuel gas samples representative of the fuel gas burned in Boiler #11. The method of compliance demonstration involving F-factor statistical significance is subject to change upon agreement with the Department and CHS (40 CFR 60, Appendix A, Reference Method 19).
5. CHS shall install and operate a volumetric stack flow rate monitor on Boiler #11. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1. The volumetric stack flow rate monitor is required within 180 days of the issuance of MAQP #1821-21 (ARM 17.8.749).

E. Testing Requirements

Boiler #11 shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub> and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO<sub>x</sub> and CO emission limits contained in Sections XII.C.2 and 3 (ARM 17.8.105 and ARM 17.8.749).

F. Compliance Determinations (ARM 17.8.749).

1. In addition to stack testing required in Section XII.E, compliance determinations for the NO<sub>x</sub> limit in Section XII.C for Boiler #11 shall also be based upon monitoring data as required in Section XII.D.
2. Compliance with the opacity limitation listed in Section XII.B shall be determined using EPA Reference Method 9 observations by a qualified observer or a certified COMS.

G. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The quarterly report shall also include the following:

1. SO<sub>2</sub> emission data from the refinery fuel gas system continuous H<sub>2</sub>S concentration monitor required by Section III. The SO<sub>2</sub> emission rates shall be reported for the following averaging periods:
  - a. Average lb/hr per calendar day
  - b. Total lb per calendar day
  - c. Total tons per month
2. NO<sub>x</sub> emission data from the CEMS, fuel gas flow rate meter, and emission factors developed from the most recent compliance source test. The NO<sub>x</sub> emission rates shall be reported for the following averaging periods:
  - a. Average lb/MMBTU per calendar day
  - b. Total tons per month
  - c. lb/MMBTU per rolling 30-day average
3. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.
4. Monitoring downtime that occurred during the reporting period.
5. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section XII.C.1 through 4.
6. Reasons for any emissions in excess of those specifically allowed in Section XII.C with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section XIII: Limitations and Conditions for the Railcar Light Product Loading Rack and Vapor Combustion Unit (VCU)

- A. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements of ARM 17.8.342, as specified in 40 CFR Part 63, NESHAP for Source Categories.
  1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
  2. Subpart R – Gasoline Distribution MACT.
  3. Subpart CC – Refinery MACT I shall apply to, but not be limited to, the product loading rack and VCU. The Gasoline Loading Rack provisions in Subpart CC require compliance with certain Subpart R provisions.

B. The Railcar Light Product Loading Rack and VCU shall be operated and maintained as follows:

1. CHS' railcar light product loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from railcars during gasoline product loading (ARM 17.8.342 and ARM 17.8.752).
2. CHS' collected vapors shall be routed to the VCU at all times. In the event the VCU is inoperable, CHS may continue to load distillates with a Reid vapor pressure of less than 27.6 kilopascals, provided the Department is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.749).
3. Loadings of liquid products into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using procedures as listed in 40 CFR 63, Subpart R (ARM 17.8.342 and ARM 17.8.752).

C. Emission Limitations for the Railcar Light Product Loading Rack VCU

1. The total VOC emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 milligrams per liter (mg/L) of gasoline loaded (ARM 17.8.342 and ARM 17.8.752).
2. The total CO emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.752).
3. The total NO<sub>x</sub> emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 4.0 mg/L of gasoline loaded (ARM 17.8.752).
4. CHS shall not cause or authorize to be discharged into the atmosphere from the VCU:
  - a. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.752); and
  - b. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO<sub>2</sub> (ARM 17.8.752).

D. Monitoring and Testing Requirements

1. CHS shall perform the testing and monitoring procedures, as applicable, specified in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart R).
2. CHS shall install and continuously operate a thermocouple and an associated recorder for temperature monitoring in the firebox or ductwork immediately downstream in a position before any substantial heat occurs and develop an operating parameter value in accordance with the provisions of 40 CFR 63.425 and 63.427 for the VCU. CHS shall install and continuously operate an ultraviolet flame detector and relay system which will render the loading rack inoperable if a flame is not present at the VCU firebox or any other equivalent device, to detect the presence of a flame (ARM 17.8.342 and ARM 17.8.752).

3. The VCU shall be initially tested for VOCs, and compliance demonstrated with the emission limitation contained in Section XIII.C.1 within 180 days of initial startup and testing continued every 5 years, or according to another testing/monitoring schedule as may be approved by the Department. CHS shall perform the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).
4. The VCU shall be initially tested for CO and NO<sub>x</sub>, concurrently, and compliance demonstrated with the CO and NO<sub>x</sub> emission limitations contained in Section XIII.C.2 and 3 within 180 days of initial start up (ARM 17.8.105).

Section XIV: Limitations and Conditions for Boiler #12

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):
  1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
  2. Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units applies to Boiler #12.
  3. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to Boiler #12.
  4. Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries applies to the refinery fuel gas supply lines to Boiler #12.
- B. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in Boiler #12 (ARM 17.8.304 (2)).
- C. Limitations on Boiler #12
  1. SO<sub>2</sub> emissions from Boiler #12 shall not exceed (40 CFR 60, Subpart Ja, ARM 17.8.340, ARM 17.8.752):
    - a. 60 ppmvd H<sub>2</sub>S refinery fuel gas, on a rolling 365-calendar day average
    - b. 5.84 tons/rolling 12-calendar month total
    - c. 3.60 lb/hr
  2. NO<sub>x</sub> emissions from Boiler #12 shall not exceed (ARM 17.8.752):
    - a. 0.02 lbs/MMBtu-HHV, on a rolling 365-calendar day average
    - b. 18.31 tons/rolling 12-calendar month total
    - c. 4.18 lb/hr

3. During periods of startup or shutdown, CO emissions from Boiler #12 shall not exceed 23 lb/hr on a 24-hour rolling average (ARM 17.8.752). Otherwise, CO emissions shall not exceed (ARM 17.8.752):
  - a. 400 ppm<sub>vd</sub> at 3% oxygen on a 30-day rolling average
  - b. 36.63 tons/rolling 12-calendar month total
  - c. 15.26 lb/hr
4. VOC Emissions from the Boiler #12 shall not exceed 4.81 tons/rolling 12-calendar month total (ARM 17.8.752).
5. Boiler #12 shall be fitted with ultra low NO<sub>x</sub> burners with FGR (ARM 17.8.752).
6. CHS shall not fire fuel oil in this unit (ARM 17.8.749 and ARM 17.8.752).

D. Monitoring requirements

1. CHS shall install and operate the following (CEMS/CERMS) for Boiler #12:
  - a. NO<sub>x</sub> (40 CFR 60, Subpart Db)
  - b. O<sub>2</sub> (40 CFR 60, Subpart Db)
2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subpart Db 60.40b through 60.49b, Subparts J, 60.100-108, Subparts Ja, 60.100a-108a, and Appendix A, Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F (ARM 17.8.749 and ARM 17.8.342).
3. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated (ARM 17.8.749).
4. With exception to the initial performance test period, compliance with the lb/MMBtu limit(s) will be demonstrated using statistically significant F-factor values. The factor will be updated on a regular basis using data from all valid fuel gas samples representative of the fuel gas burned in Boiler #12. The method of compliance demonstration involving F-factor statistical significance is subject to change upon agreement with the Department and CHS (40 CFR 60, Appendix A, Reference Method 19).
5. CHS shall install and operate a volumetric stack flow rate monitor on Boiler #12. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1 (ARM 17.8.749).

E. Testing Requirements

Boiler #12 shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO<sub>x</sub> and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO<sub>x</sub> and CO emission limits contained in Sections XIV.C.2 and 3 (ARM 17.8.105 and ARM 17.8.749).

F. Compliance Determinations (ARM 17.8.749).

1. In addition to stack testing required in Section XIV.E, compliance determinations for the NO<sub>x</sub> limits in Section XIV.C for Boiler #12 shall also be based upon monitoring data as required in Section XIV.D.
2. Compliance with the opacity limitation listed in Section XIV.B shall be determined using EPA Reference Method 9 observations by a qualified observer or a certified COMS.
3. Compliance with the limit in Section XIV.C.2.c. shall be determined using the NO<sub>x</sub> CEM required in Section XIV.D.1 and the volumetric stack flow rate monitor required in Section XIV.D.5.

G. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The quarterly report shall also include the following:

1. SO<sub>2</sub> emission data from the refinery fuel gas system continuous H<sub>2</sub>S concentration monitor required by Section III. The SO<sub>2</sub> emission rates shall be reported for the following averaging periods:
  - a. Average lb/hr per calendar day
  - b. Total lb per calendar day
  - c. Total tons per month
2. NO<sub>x</sub> emission data from the CEMS, fuel gas flow rate meter, and emission factors developed from the most recent compliance source test. The NO<sub>x</sub> emission rates shall be reported for the following averaging periods:
  - a. Average lb/MMBTU per calendar day
  - b. Total tons per month
  - c. lb/MMBTU per rolling 30-day average
  - d. lb/MMBtu per rolling 365-day average
  - e. Daily average and maximum lb/hr
3. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.
4. Monitoring downtime that occurred during the reporting period.
5. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section XIV.C.1 through 4.

6. Reasons for any emissions in excess of those specifically allowed in Section XIV.C with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

Section XV: Benzene Reduction Unit

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable:
  1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
  2. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to the Platformer Splitter Reboiler.
  3. Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to all of the fugitive VOC emitting components added in the affected facility.
  4. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to, but not be limited to, any new, modified, or reconstructed affected facility associated with the benzene reduction project.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
  1. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
  2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (Refinery MACT I) applies to certain parts of the Benzene Reduction Unit.
- C. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in the Benzene Reduction Unit (ARM 17.8.304 (2)).
- D. Limitations on Platformer Splitter Reboiler
  1. SO<sub>2</sub> emissions from the Platformer Splitter Reboiler shall not exceed:
    - a. 60 ppm<sub>v</sub> H<sub>2</sub>S in refinery fuel gas, 365-day rolling average for the Platformer Splitter Reboiler (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja)
    - b. 1.18 tons/ rolling 12-calendar month total (ARM 17.8.749)
    - c. 0.72 lb/hr (ARM 17.8.749)

2. NO<sub>x</sub> emissions from the Platformer Splitter Reboiler shall not exceed:
  - a. 6.99 tons/ rolling 12-calendar month total (ARM 17.8.749)
  - b. 1.60 lb/hr (ARM 17.8.752)
3. CO emissions from the Platformer Splitter Reboiler shall not exceed:
  - a. 13.62 tons/ rolling 12-calendar month total (ARM 17.8.749)
  - b. 3.11 lb/hr (ARM 17.8.752)
4. PM/PM<sub>10</sub> emissions from the Platformer Splitter Reboiler shall not exceed:
  - a. 1.31 tons/ rolling 12-calendar month total (ARM 17.8.749)
  - b. 0.30 lb/hr (ARM 17.8.752)
5. VOC emissions from the Platformer Splitter Reboiler shall not exceed 0.64 tons/rolling 12-calendar month total (ARM 17.8.752).
6. The Platformer Splitter Reboiler shall be fitted with ULNBs (ARM 17.8.752).
7. The heat input rate for the Platformer Splitter Reboiler shall not exceed 39.9 MMBtu-HHV/hr (ARM 17.8.749).

E. Limitations on Wastewater System Components

1. All new drains associated with the benzene reduction project will be routed to the sewer system that is NSPS Subpart QQQ compliant and all such drains will be treated as subject to NSPS Subpart QQQ requirements (ARM 17.8.752).
2. All new junction boxes/vessels constructed as part of the benzene reduction project will be either water sealed, equipped with vent pipes meeting NSPS Subpart QQQ standards (applicable to new junction boxes), or equipped with closed vent systems and control devices that are designed and operated to meet the control requirements of NSPS Subpart QQQ (ARM 17.8.752).

F. Testing Requirements

The Platformer Splitter Reboiler (P-HTR-3) shall be initially tested for NO<sub>x</sub> and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO<sub>x</sub> and CO emission limits contained in Sections XV.D.2 and 3 (ARM 17.8.105 and ARM 17.8.749).

G. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The quarterly report shall also include the following:

1. SO<sub>2</sub> emission data from the refinery fuel gas system continuous H<sub>2</sub>S concentration monitor required by Section III. The SO<sub>2</sub> emission rates shall be reported for the following averaging periods:

- a. Average lb/hr per calendar day
  - b. Total lb per calendar day
  - c. Total tons per month
2. NO<sub>x</sub> emission data from the fuel gas flow rate meter and emission factors developed from the most recent compliance source test. The NO<sub>x</sub> emission rates shall be reported for the following averaging periods:
    - a. Average lb/hr per calendar day
    - b. Total tons per month
  3. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates.
  4. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section XV.D.1 through 5.
  5. Reasons for any emissions in excess of those specifically allowed in Section XV.D with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

H. Notification Requirements

CHS shall provide the Department (both the Billings regional office and the Helena office) with written notification of the actual start-up date of the Platformer Splitter Reboiler within 15 days after the actual start-up date (ARM 17.8.340 and ARM 17.8.749).

Section XVI: Limitations and Conditions for Storage Tanks (Tanks 135-143 and Additive Tanks 1-4)

- A. CHS shall comply with all applicable standards and limitations, and the testing, monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable:
  1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
  2. 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.
- B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):
  1. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
  2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tanks 135, 136, 137, 138, 142, and 143, which are classified as Group 1 storage vessels.

3. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tank 139, which is classified as a Group 2 storage vessel.

C. Limitations for Storage Tanks

1. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 (2)).
2. Storage Tanks 135 and 136 shall each be equipped with an external floating roof and submerged fill piping (ARM 17.8.752).
3. VOC emissions from Storage Tanks 137, 138, 142, and 143 shall be controlled by the installation and use of an internal floating roof and submerged fill piping (ARM 17.8.340, 40 CFR 60, Subpart Kb, and ARM 17.8.752).
4. Storage Tank 139 shall only store #1 or #2 diesel fuel and the VOC emissions from Storage Tank 139 shall be controlled by the installation and use of a fixed roof with pressure/vacuum vents and a submerged fill piping (ARM 17.8.749).
5. Until the new loading rack(s) and associated equipment are operational, the combined VOC emissions from Storage Tanks 135 and 136 shall not exceed 12.6 tons/rolling 12-calendar month total. This limit includes emissions while the roofs are floating and emissions during time periods that the tank roofs are landed on the legs (ARM 17.8.749).
6. The total annual VOC emissions from the truck loading rack(s), VCU and associated equipment (which includes the existing and proposed new truck loading rack, existing and proposed VCU and all associated storage tanks (135-143 and Additive Tanks # 1-4), the propane loading rack, and any fugitives shall not exceed 39.23 TPY based on a rolling 12-calendar month total. This is total combined VOC emission limit for the units listed in Section (XVI) and Section VI (ARM 17.8.749).
7. A monitoring and maintenance program, as described under 40 CFR Part 60 VVa, and meeting the requirements of 40 CFR Part 60 GGGa shall be instituted (ARM 17.8.340 and ARM 17.8.752).

D. Monitoring Requirements

1. Combined VOC emissions from Storage Tanks 135-139, 142-143, and Additive tanks 1-4 shall be calculated and monitored utilizing the EPA TANKS software with key parameters of throughput and material properties. Tank emissions during periods the tank roofs are landed on its legs shall be calculated using appropriate AP-42 emissions equations (ARM 17.8.749).
2. CHS shall document, by month, the total VOC emissions from Storage Tanks 135-143; and Additive Tanks 1 -4 and all associated fugitive sources. This must also include emissions while the roofs of the internal floating and external floating tanks are floating and emissions during time periods that the tank roofs are landed on the legs. This monthly information and the emissions relating to

the operation of the truck loading facilities, VCU and all associated fugitives sources shall be used to verify compliance with the rolling 12-month limitations in Section(s) XVI.C.5, XVI.C.6, and VI.C.1.

E. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The quarterly report shall also include the applicable 12-month rolling total VOC emissions, by month, as required in XVI.C.5 and XVI.C.6 and VI.C.6.

F. Notification Requirements

CHS shall provide the Department (both the Billings regional office and the Helena office) with written notification of the actual start-up date of Storage Tanks 137-143; Additive Tanks 1-4 within 15 days after the actual start-up date of each tank (ARM 17.8.340 and ARM 17.8.749).

Section XVII: Limitations and Conditions for Storage Tank 133

A. CHS shall comply with all applicable standards and limitations, and the testing, monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable:

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
2. Subpart UU - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture.

B. CHS shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements specified in 40 CFR Part 63, NESHAPs for Source Categories (ARM 17.8.342):

1. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tank 133, which is classified as a Group 2 storage vessel.

C. Except where 40 CFR 60, Subpart UU is applicable, CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 (2)).

D. Limitations for Storage Tank 133

1. VOC emissions from Storage Tank 133 shall not exceed 12.3 tons/rolling 12-calendar month total (ARM 17.8.749).
2. Storage Tank 133 shall be a fixed roof tank with a pressure/vacuum vent and submerged fill piping. While in asphalt and gas oil service, the tank may be heated and may be operated without the pressure/vacuum vent (ARM 17.8.752).

3. A monitoring and maintenance program, as described under 40 CFR 60, Subpart VVa, and meeting the requirements of 40 CFR60, Subpart GGGa shall be instituted (ARM 17.8.340 and ARM 17.8.752).

E. Monitoring Requirements

1. VOC emissions from Storage Tank 133 shall be calculated and monitored utilizing the EPA TANKS software with key parameters of throughput and material properties (ARM 17.8.749).

F. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

1. CHS shall document, by month, the total VOC emissions from Tanks 133. The monthly information shall be used to verify compliance with the rolling 12-month limitation in Section XVII.D.1. (ARM 17.8.749).
2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. Copies of the quarterly emission report shall be submitted to both the Billings regional office and the Helena office of the Department. The quarterly report shall also include the 12-month rolling total VOC emissions, by month, for Storage Tank 133.

Section XVIII: Wastewater Facilities

- A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60, NSPS. The following subparts, at a minimum, are applicable (ARM 17.8.340):

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.
2. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater System, shall apply to, but not be limited to:
  - Desalter Wastewater Three-Phase Separator(s)
  - API Separator(s)
  - CPI Separator(s)
  - DAF (Dissolved Air Flotation) Units

B. Limitations for Wastewater Facilities

1. The Desalter Wastewater Three Phase Separator(s) shall be equipped with a vapor collection system to return emissions from the enclosed vapor space to the process (ARM 17.8.752).
2. CHS shall equip, operate, and maintain the API Separator(s), CPI Separator(s) and the DAF Units with a vapor collection system to collect and route emissions from the enclosed vapor space to a carbon adsorption system, designed and operated to reduce VOC emissions by 95% or greater (ARM 17.8.340, ARM 17.8.752, 40 CFR 60, Subpart QQQ).

C. Monitoring Requirements

1. The concentration level of the organic compounds in the exhaust vent stream from the carbon adsorption system(s) shall be monitored on a daily basis or at intervals no greater than 20% of the design carbon replacement interval. The existing carbon shall be replaced with fresh carbon immediately when carbon breakthrough is indicated (ARM 17.8.749).

D. Operational and Emission Inventory Reporting Requirements (ARM 17.8.749)

1. CHS shall keep records and furnish reports to the Department as required by 40 CFR 60, Subpart QQQ, for requirements not overridden by 40 CFR 63, Subpart CC.
2. CHS shall provide copies to the Department, upon the Department's request, of any records of testing results, monitoring operations, recordkeeping and report results as specified under 40 CFR 60, Subpart QQQ, Sections 60.693-2, 60.696, 60.697, and 60.698, for requirements not overridden by 40 CFR 63, Subpart CC.

E. Notification Requirements

1. CHS shall provide the Department (both the Billings regional office and the Helena office) with written notification of the actual start-up date of the Wastewater Three-Phase Separator(s), API Separator(s), CPI Separator(s), and DAF Units within 15 days after the actual start-up date (ARM 17.8.340 and ARM 17.8.749).

Section XIX: General Conditions

- A. Inspection - CHS shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.
- B. Waiver - The permit and all the terms, conditions, and matters stated herein shall be deemed accepted if CHS fails to appeal as indicated below.
- C. Compliance with Statutes and Regulations - Nothing in this permit shall be construed as relieving CHS of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq.* (ARM 17.8.756).
- D. Enforcement - Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement as specified in Section 75-2-401 *et seq.*, MCA.
- E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The

issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

- F. Permit Inspection - As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by Department personnel at the location of the permitted source.
- G. Duration of Permit - Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762).
- H. Permit Fees - Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, failure to pay the annual operation fee by CHS may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

## ATTACHMENT A

### Plant-Wide Refinery Limitations and Conditions Compliance Determination

1. Gas fired external combustion
  - a. SO<sub>2</sub>
    - i. Calculation Basis: AP-42 Section 1-4 (7/98 revision) and complete conversion of fuel gas H<sub>2</sub>S to SO<sub>2</sub>.
    - ii. Key Parameters: Monthly fuel use (scf) per combustion unit and refinery fuel gas H<sub>2</sub>S content from CEMS.
  - b. NO<sub>x</sub>, CO, PM<sub>10</sub>/PM, VOC
    - i. Calculation Basis: AP-42 Section 1-4 (7/98 revision).
    - ii. Key Parameters: Monthly fuel use (scf) per combustion unit and monthly average fuel gas heat content.
2. Fuel oil fired external combustion
  - a. SO<sub>2</sub>
    - i. Calculation Basis: Methodology required in the Billings-Laurel SO<sub>2</sub> SIP and Appendix G of the CHS Consent Decree.
    - ii. Key Parameters: Sulfur content and specific gravity of alkylation unit polymer pursuant to Appendix G of the CHS Consent Decree.
3. Gas fired internal combustion
  - a. SO<sub>2</sub>
    - i. Calculation Basis: AP-42 Section 1-4 (7/98 revision) and complete conversion of fuel gas H<sub>2</sub>S to so<sub>2</sub>
    - ii. Key Parameters: Monthly fuel use (scf) per combustion unit and fuel gas H<sub>2</sub>S and Sulfur content.
  - b. NO<sub>x</sub>, CO
    - i. Calculation Basis: AP-42 Section 3-2 (10/96 revision).
    - ii. Key Parameters: Monthly fuel use (scf) per combustion unit and monthly average fuel gas heat content.
  - c. PM<sub>10</sub>/PM: Not applicable – not a significant source
  - d. VOC  
Calculation Basis: AP-42 Section 3-2 (10/96 revision)  
Key Parameters: Monthly fuel use (scf) per combustion unit and monthly average fuel gas heat content.

4. Zone D, ULSD Unit (900 Unit), Hydrogen Plant (1000 Unit), Delayed Coker Unit combustion sources, Boiler #11, and NHT Charge Heater (H-8301)
  - a. SO<sub>2</sub>: Calculation Basis: CEMS data and methodology required in the Billings/Laurel SO<sub>2</sub> SIP
  - b. NO<sub>x</sub>
    - i. Calculation Basis: NO<sub>x</sub> and O<sub>2</sub> CEMS, Emission factors based on annual stack tests.
    - ii. Key Parameters: NO<sub>x</sub> stack tests, monthly fuel use (scf) per combustion unit.
  - c. CO
    - i. Calculation Basis: CO and O<sub>2</sub> CEMS, Emission factors based on annual stack tests.
    - ii. Key Parameters: CO stack tests, monthly fuel use (scf) per combustion unit.
  - d. PM<sub>10</sub>/PM
    - i. Calculation Basis: AP-42 Section 1-4 (7/98 revision).
    - ii. Key Parameters: Monthly fuel use (scf) per combustion unit and monthly average fuel gas heat content.
  - e. VOC
    - i. Calculation Basis: Emission factors based on annual stack tests for sources burning refinery fuel gas. For sources firing only natural gas, the most current VOC stack test will be used to develop emission factors.
    - ii. Key Parameters: VOC stack test.
5. Fugitive equipment leaks
  - a. SO<sub>2</sub>, NO<sub>x</sub>, CO, PM<sub>10</sub>/PM: Not applicable
  - b. VOC
    - i. Calculation Basis: EPA factors and NSPS and MACT control efficiencies (EPA-453/R-95-017).
    - ii. Key Parameters: Component counts by type and service.
6. Boilers #10 and #12
  - a. SO<sub>2</sub>
    - i. Calculation Basis: Complete conversion of fuel gas H<sub>2</sub>S to SO<sub>2</sub>.

- ii. Key Parameters: Monthly fuel use (scf) per combustion unit and refinery fuel gas H<sub>2</sub>S content from CEMS.
  - b. NO<sub>x</sub>
    - i. Calculation Basis: NO<sub>x</sub> and O<sub>2</sub> CEMS, Volumetric stack flow rate monitor, Emission factors based on stack tests.
    - ii. Key Parameters: NO<sub>x</sub> and O<sub>2</sub> CEMS, Reference Method 19, NO<sub>x</sub> stack tests, monthly fuel use (scf), volumetric stack flow rate.
  - c. CO
    - i. Calculation Basis: CO and O<sub>2</sub> CEMS, Emission factors based on stack tests.
    - ii. Key Parameters: CO stack tests, monthly fuel use (scf).
  - d. PM<sub>10</sub>/PM
    - i. Calculation Basis: AP-42 Section 1-4 (7/98 revision).
    - ii. Key Parameters: Monthly fuel use (scf) and monthly average fuel gas heat content.
  - e. VOC
    - i. Calculation Basis: Emission factors based on stack tests.
    - ii. Key Parameters: VOC stack tests, monthly fuel use (scf).
- 7. FCCU
  - a. SO<sub>2</sub>

Calculation Basis: CEMS data and methodology required in CHS Consent Decree, NSPS Subpart J, and the Billings/Laurel SO<sub>2</sub> SIP
  - b. NO<sub>x</sub>

Calculation Basis: CEMS data and methodology required in CHS Consent Decree, NSPS Subpart J, and FCCU Regenerator flue gas flow rate.
  - c. CO
 

Calculation Basis: CEMS data and methodology required in CHS Consent Decree and NSPS Subpart Ja, and FCCU Regenerator flue gas flow rate.
  - d. PM<sub>10</sub>/PM
    - i. Calculation Basis: Annual stack test results.
    - ii. Key Parameters: Monthly FCC charge rate (bbl).

- e. VOC
    - i. Calculation Basis: AP-42 Section 5.1 (1/95 revision) and assumed 98% control efficiency.
    - ii. Key Parameters: Monthly FCC charge rate (bbl).
8. Zone A SRU Incinerator
- a. SO<sub>2</sub>: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO<sub>2</sub> SIP
  - b. NO<sub>x</sub>
    - i. Calculation Basis: Emission factors based on every 5-year stack tests.
    - ii. Key Parameters: Every 5-year NO<sub>x</sub> stack test, monthly fuel use (scf).
  - c. CO, PM<sub>10</sub>/PM, VOC
    - i. Calculation Basis: AP-42 Section 1-4 (7/98 revision).
    - ii. Key Parameters: Monthly fuel use (scf) and average fuel gas heat content.
9. Zone D SRU Incinerator
- a. SO<sub>2</sub>: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO<sub>2</sub> SIP
  - b. NO<sub>x</sub>
    - i. Calculation Basis: Emission factors based on annual stack tests.
    - ii. Key Parameters: Annual NO<sub>x</sub> stack test, monthly fuel use (scf).
  - c. CO, PM<sub>10</sub>/PM, VOC: Not applicable – not a significant source
10. Zone E SRU Incinerator
- a. SO<sub>2</sub>: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO<sub>2</sub> SIP
  - b. NO<sub>x</sub>
    - i. Calculation Basis: Emission factors based on every 5ve-year stack tests.
    - ii. Key Parameters: Every 5-year NO<sub>x</sub> stack test, monthly fuel use (scf).
  - c. CO, PM<sub>10</sub>/PM, VOC: Not applicable – not a significant source

11. Wastewater
  - a. SO<sub>2</sub>, NO<sub>x</sub>, CO, PM<sub>10</sub>/PM: Not applicable – not a source
  - b. VOC
    - i. Calculation Basis: AP-42, Table 5.1-2 (1/95 rev.).
    - ii. Key Parameters: Monthly wastewater flow (gal) from Lab Information Management System (LIMS).
  
12. Cooling towers
  - a. SO<sub>2</sub>, NO<sub>x</sub>, CO: Not applicable – not a source
  - b. PM<sub>10</sub>/PM: Cooling tower design (Delayed coker unit cooling tower applicable)
  - c. VOC
    - i. Calculation Basis: AP-42, Section 5.1 (1/95 rev.).
    - ii. Key Parameters: Monthly cooling tower circulation (gal).
  
13. Loading facilities
  - a. SO<sub>2</sub>: Not applicable – not a source
  - b. NO<sub>x</sub>
    - i. Calculation Basis: VCU stack tests for lb NO<sub>x</sub>/gal loaded.
    - ii. Key Parameters: Monthly volume of materials loaded from yield accounting.
  - c. CO
    - i. Calculation Basis: VCU stack tests for lb CO/gal loaded.
    - ii. Key Parameters: Monthly volume of materials loaded from yield accounting.
  - d. PM<sub>10</sub>/PM: Not applicable – not a significant source
  - e. VOC
    - i. Calculation Basis: AP-42, Section 5.2-4 (1/95 rev.) and VCU stack tests for lb VOC/gal loaded.
    - ii. Key Parameters: Monthly volume of material throughput from yield accounting, material property data (VP, MW, etc.).
  
14. Storage tanks
  - a. SO<sub>2</sub>, NO<sub>x</sub>, CO, PM<sub>10</sub>/PM: Not applicable – not a source

- b. VOC
  - i. Calculation Basis: actual emission, EPA TANKS4.0, AP-42 and other reasonable sources as outlined in the application for MAQP #1821-27.
  - ii. Key Parameters: Monthly volume of material throughput from yield accounting, material property data (VP, MW, etc.).

Montana Air Quality Permit (MAQP) Analysis  
CHS Inc. – Laurel Refinery  
MAQP #1821-27

I. Introduction/Process Description

A. Site Location/Description

The CHS Inc. (CHS) Laurel Refinery is a petroleum refinery located in the South ½ of Section 16, Range 24 East, Township 2 South, in Yellowstone County. A complete list of permitted equipment is available in the permit, with the exception of the source categories for the Plant-wide Applicability Limit (PAL), which are listed below.

1. Gas-fired external combustion source type, includes:

- #1 crude heater, crude preheater, #1 crude vacuum heater
- #2 crude heater, #2 crude vacuum heater
- Alkylation Unit hot oil belt heater
- Platformer Heater (P-HTR-1), platformer debutanizer heater
- Fluid Catalytic Cracking (FCC) Charge Heater (FCC-Heater-1)
- Naphtha Hydrotreater (NHT) Charge Heater (H-8301), NHT Reboiler Heater #1 (H-8302), NHT Reboiler Heater #2 (H-8303), and NHT Splitter Reboiler (H-8304)
- Zone D Hydrogen Plant Reformer Heater (H-101), Reformer Heater in the 100 Unit Hydrogen Plant (H-102), Reactor Charge Heater (H-201), Fractionator Feed Heater (H-202)
- Ultra Low Sulfur Diesel (ULSD) Unit Reactor charge heater (H-901), ULSD Unit Fractionation heater (H-902)
- Hydrogen Plant Reformer heater (H-1001)
- Coker Charge Heater (H-7501)
- Asphalt Loading Heater #1
- #1 fuel oil heater, #60 tank heater
- Boiler #5, Boiler #9, Boiler #10, Boiler #11, and Boiler #12
- Platformer Splitter Reboiler (P-HTR-3)
- FCC Charge Heater (FCC-Heater-NEW)

2. Fuel oil-fired external combustion sources, includes: #4 boiler, and #5 boiler (until startup of Boiler #12);

3. Gas-fired internal combustion source, includes: Platformer recycle turbine;
4. FCC unit (FCCU) Regenerator;
5. Zone A Sulfur Recovery Unit (SRU) Tail Gas Incinerator (TGI, SRU-AUX-4);
6. Zone D SRU Incinerator;
7. Delayed Coker Unit: Zone E SRU/Tail Gas Treatment Unit (TGTU)/TGI;
8. Fugitive equipment leaks include all equipment, as defined in 40 Code of Federal Regulations (CFR) 60, Subpart VV, in hydrocarbon service;
9. Wastewater Sewers, Separation and Treatment facilities;
10. Cooling tower sources: #1 cooling tower (CT), #2 CT, #3 CT, #5 CT, and #6 CT;
11. Loading facilities: light product truck rack and vapor combustion unit (VCU), heavy oil truck rack, heavy oil rail rack; and railcar light loading rack and VCU; and
12. Storage tanks: tank numbers 2, 7, 12, 41, 47, 56, 60, 61, 62, 63, 65, 66, 67, 68, 70, 71, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 85, 86, 87, 88, 91, 92, 93, 94, 95, 96, 97, 98, 99, 100, 101, 102, 103, 104, 105, 106, 107, 108, 109, 110, 111, 112, 113, 114, 115, 116, 117, 118, 119, 120, 121, 122, 123, 126, 127, 128, 129, 133, 135, 136, 137, 138, 139, 140, 141, 142, 143, Additive Tanks (1-4), B-1, B-2, B-7, firetk 2, firetk 3, firetk 4, TGTU-VSSL-6, and coker sludge storage tank (TK-7504).

## B. Permit History

On May 11, 1992, Cenex Harvest States Cooperatives (Cenex) was issued **MAQP #1821-01** for the construction and operation of a hydro-treating process to desulfurize FCC Unit feedstocks. The existing refinery property lies immediately south of the City of Laurel and about 13 miles southwest of Billings, Montana. The new equipment for the desulfurization complex is located near the western boundary of the existing refining facilities.

The hydrodesulfurization (HDS) process is utilized to pretreat Fluid Catalytic Cracking Unit (FCCU) feeds by removing metal, nitrogen, and sulfur compounds from these feeds. The proposed HDS unit also improved the quality of refinery finished products including gasoline, kerosene, and diesel fuel. The HDS project significantly improved the finished product quality by reducing the overall sulfur contents of liquid products from the Cenex Refinery. The HDS unit provided low sulfur gas-oil feedstocks for the FCCU, which resulted in major reductions of sulfur oxide emissions to the atmosphere. However, only a minor quantity of the proposed sulfur dioxide (SO<sub>2</sub>) emission reductions was made federally enforceable.

The application was not subject to the New Source Review (NSR) program for either nonattainment or Prevention of Significant Deterioration (PSD) since Cenex chose to "net out of major modification review" for the affected pollutants due to contemporaneous emission reductions at an existing emission unit.

The application was deemed complete on March 24, 1992. Additional information was received on April 16, 1992, in which Cenex proposed new short-term emission rates based upon modeled air quality impacts.

The basis for the permit application was due to a net contemporaneous emissions increase that was less than the significant level of 40 tons per year (TPY) for SO<sub>2</sub> and nitrogen oxides (NO<sub>x</sub>). The application referred to significant SO<sub>2</sub> emission reductions, which were expected by addition of the HDS project. These anticipated major SO<sub>2</sub> reductions were not committed to by Cenex under federally enforceable permit conditions and limitations. The contemporaneous emissions decrease for SO<sub>2</sub> and NO<sub>x</sub>, which were made federally enforceable under this permitting action, amount to approximately 15.5 and 23.7 tons per year, respectively.

Construction of the HDS/sulfur recovery complex was completed in December 1993 and the 180-day-shakedown period ended in June 1994.

**MAQP #1821-02** was issued on February 1, 1997, to authorize the installation of an additional boiler (Boiler #10) to provide steam for the facility. Cenex submitted the original permit application for a 182.50-million British thermal units per hr (MMBtu/hr) boiler on February 9, 1996. This size boiler is a New Source Performance Standard (NSPS) affected facility and the requirements of NSPS Subpart Db would have applied to the boiler. On November 15, 1996, Cenex submitted a revised permit application proposing a smaller boiler (99.90 MMBtu/hr). The manufacturer of the proposed boiler has not been identified; however, the boiler is to be rated at approximately 80,000 lbs steam/hour with a heat input of 99.9 MMBtu/hour. The boiler shall have a minimum stack height of 75 feet above ground level. The boiler will be fired on natural gas until November 1, 1997, at which time Cenex will be allowed to fire refinery fuel gas in the boiler. The requirements of NSPS Subpart Dc apply to the boiler. The requirements of NSPS Subpart J and GGG will also apply as of November 1, 1997. Increases in emissions from the new boiler are detailed in the permit analysis for MAQP #1821-02. Modeling performed has shown that the emission increase will not result in a significant impact to the ambient air quality.

Cenex has also requested a permit alteration to remove the SO<sub>2</sub> emission limits for the C-201B compressor engine because the permit already limits C-201B to be fired on either natural gas or unodorized propane. Cenex also requested that if the SO<sub>2</sub> emission limits could not be removed, the limits should be corrected to allow for the combustion of natural gas and propane. The Department of Environmental Quality (Department) has altered the permit to allow for burning odorized propane in the C-201B compressor.

Cenex also requested a permit modification to change the method of determining compliance with the HDS Complex emitting units. MAQP #1821-01 requires that compliance with the hourly (lb/hr) emission limits be determined through annual source testing and that the daily (lb/day), annual (ton/yr), and Administrative Rules of Montana (ARM) 17.8 Subchapter 8 requirements (i.e., PSD significant levels and review) be determined by using actual fuel burning rates and the manufacturer's guaranteed emission factors listed in Attachment B. Cenex has requested to use actual fuel burning rates and fixed emission factors determined from previous source test data in order to determine compliance with the daily (lb/day) and annual (ton/yr) emission limits. The Department agrees that actual stack testing data is preferred to manufacturer's data for the development of emission factors. However, the Department is requiring that the emission factor be developed from the most recent source test and not on an average of previous source tests. The permit has been changed to remove Attachment B and rely on emission factors derived from the most recent source test, along with actual fuel flow rates for compliance determinations. However, in order to determine compliance with ARM 17.8 Subchapter 8, Cenex shall continue to monitor the fuel gas flow rates in both scf/hr and scf/year.

On June 4, 1997, Cenex was issued **MAQP #1821-03** to modify emissions and operational limitations on components in the Hydrodesulfurization Complex at the Laurel refinery. The unit was originally permitted in 1992, but has not been able to operate adequately under the emissions and operational limitations originally proposed by Cenex and permitted by the Department. This permitting action corrected these limitations and conditions. The new limitations established by this permitting action were based on operational experience and source testing at the facility and the application of Best Available Control Technology (BACT).

The following emission limitations were modified by this permit.

Source	Pollutant	Previous Limit	New Limit
SRU Incinerator stack (E-407 & INC-401)	SO <sub>2</sub>	291.36 lb/day	341.04 lb/day
	NO <sub>x</sub>	2.1 ton/yr 11.52 lb/day 0.48 lb/hr	3.5 ton/yr 19.2 lb/day 0.8 lb/hr
Compressor (C201-B)	NO <sub>x</sub>	18.42 ton/yr	30.42 ton/yr
		6.26 lb/hr	7.14 lb/hr
	CO	16.45 ton/yr	68.6 ton/yr
		5.15 lb/hr - when on natural gas	6.4 lb/hr - when on natural gas
VOC	6.26 ton/yr	10.1 ton/yr	
Fractionator Feed Heater (H-202)	SO <sub>2</sub>	0.53 ton/yr	4.93 ton/yr
		0.135 lb/hr	1.24 lb/hr
	NO <sub>x</sub>	6.26 ton/yr	8.34 ton/yr
		1.43 lb/hr	2.09 lb/hr
	CO	3.29 ton/yr	6.42 ton/yr
		1.00 lb/hr	1.61 lb/hr
VOC	0.26 ton/yr	0.51 ton/yr	
Reactor Charge Heater (H-201)	SO <sub>2</sub>	0.214 lb/hr	1.716 lb/hr
		0.79 ton/yr	6.83 ton/yr
	NO <sub>x</sub>	9.24 ton/yr	11.56 ton/yr
		2.11 lb/hr	2.90 lb/hr
	CO	4.86 ton/yr	8.89 ton/yr
		1.40 lb/hr	2.23 lb/hr
VOC	0.39 ton/yr	0.71 ton/yr	
Reformer Heater (H-101)	SO <sub>2</sub>	0.128 lb/hr	2.15 lb/hr
		0.48 ton/yr	3.35 ton/yr
	NO <sub>x</sub>	6.16 lb/hr	6.78 lb/hr
	VOC	0.24 ton/yr	0.35 ton/yr
Old Sour Water Stripper	SO <sub>2</sub>	304.2 ton/yr	290.9 ton/yr
	NO <sub>x</sub>	125.7 ton/yr	107.9 ton/yr

Emission limitations in this permit are based on the revised heat input capacities for units within the HDS. The following changes were made to the operational requirements of the facility.

Unit	Originally Permitted Capacity	New Capacity
SRU Incinerator stack (E-407 & INC-401)	4.8 MMBtu/hr	8.05 MMBtu/hr
Compressor (C201-B)	1600 hp (short term) 1067 hp (annual average)	1800 hp (short term and annual average)
Fractionator Feed Heater (H-202)	27.2 MMBtu/hr (short term) 20.4 MMBtu/hr (annual avg.)	29.9 MMBtu/hr (short term) 27.2 MMBtu/hr (annual avg.)
Reactor Charge Heater (H-201)	37.7 MMBtu/hr (short term) 30.2 MMBtu/hr (annual avg.)	41.5 MMBtu/hr (short term) 37.7 MMBtu/hr (annual avg.)
Reformer Heater (H-101)	123.2 MMBtu/hr (short term and annual avg.)	135.5 MMBtu/hr (short term) 123.2 MMBtu/hr (annual avg.)

It has been determined that the emission and operational rates proposed during the original permitting of the HDS unit were incorrect and should have been at the levels Cenex is now proposing. Because of this, the current action and the original permitting of the HDS must be considered one project in order to determine the permitting requirements. When combined with the original permitting of the HDS, the emission increases of NO<sub>x</sub> and SO<sub>2</sub> would exceed significant levels and subject this action to the requirements of the NSR/PSD program. During the original permitting of the HDS complex, Cenex chose to “net out” of NSR and PSD review by accepting limitations on the emissions of NO<sub>x</sub> and SO<sub>2</sub> from the old SWS. Because of the emission increases proposed in this permitting action, additional emission reductions must occur. Cenex has proposed additional reductions in emissions from the old SWS to offset the increases allowed by this permitting action. These limitations will reduce the “net emission increase” to less than significant levels and negate the need for review under the NSR/PSD program.

The new emission limits for SO<sub>2</sub> and NO<sub>x</sub> from the old SWS are 290.9 and 107.9 tons per year, respectively.

This permitting action also removes the emission limits and testing requirements for particulate matter with an aerodynamic diameter of 10 microns or less (PM<sub>10</sub>) on the HDS heaters (H-101, H-201, and H-202). These heaters combust refinery gas, natural gas, and PSA gas. The Department has determined that potential PM<sub>10</sub> emissions from these fuels are minor and that emission limits and the subsequent compliance demonstrations for this pollutant are unnecessary.

Also removed from this permit are the compliance demonstration requirements for SO<sub>2</sub> and Volatile Organic Compounds (VOC) when the combustion units are firing natural gas. The Department has determined that firing the units solely on natural gas will, in itself, demonstrate compliance with the applicable limits.

This action will result in an increase in allowable emissions of VOC and Carbon Monoxide (CO) by 4.7 tons per year and 60 tons per year, respectively. Because of the offsets provided by reducing emissions from the old SWS, this permitting action will not increase allowable emissions of SO<sub>2</sub> or NO<sub>x</sub> from the facility.

The following changes have been made to the Department's preliminary determination (PD) in response to comments from Cenex.

The emission limits for the old SWS have been revised to ensure that the required offsets are provided without putting Cenex in a non-compliance situation at issuance of the permit. The compliance determinations and the reporting requirements were also changed to reflect this requirement.

The CO emission limits for H-201 have been revised; the old limits were inadvertently left in the PD. The table included in the analysis has also been revised to reflect this change.

Section III.E.2 was changed to clarify that the firing of natural gas would show compliance with the VOC emission limits for Boiler #10.

Section F. of the General Conditions was removed because the Department has placed the applicable requirements from the permit application into the permit.

Numbering has been changed in Section III.

**MAQP #1821-04** was issued to Cenex on March 6, 1998, in order to comply with the gasoline loading rack provisions of 40 CFR 63, Subpart CC - National Emission Standards for Petroleum Refineries, by August 18, 1998. Cenex proposed to install a gasoline vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAPs) resulting from the loading of gasoline. A vapor combustion unit (VCU) was added to the product loading rack. The gasoline vapors would be collected from the trucks during loading, then routed to an enclosed flare where combustion would occur. The result of this project would be an overall reduction in the amount of VOCs (503.7 TPY) and HAPs emitted, but CO and NO<sub>x</sub> emissions would increase slightly (4.54 TPY and 1.82 TPY).

The product loading rack is used to transfer refinery products (gasoline, burner and/or diesel fuels) from tank storage to trucks, which transport gasoline and other products, to retail outlets. The loading rack consists of three arms, each with a capacity of 500 gpm. However, only two loading arms are presently used for loading gasoline at any one time. A maximum gasoline-loading rate of 2000 gpm, a maximum short-term rate, was modeled to account for future expansion.

Because Cenex's product loading rack VCU is defined as an incinerator under 75-2-215, Montana Code Annotated (MCA), a determination that the emissions from the VCU would constitute a negligible risk to public health was required prior to the issuance of a permit to the facility. Cenex and the Department identified the following HAPs from the flare, which were used in the health risk assessment. These constituents are typical components of Cenex's gasoline:

1. Benzene
2. Toluene
3. Ethyl Benzene
4. Xylenes
5. Hexane

6. 2,2,4 Trimethylpentane
7. Cumene
8. Napthalene
9. Biphenyl

The reference concentration for Benzene was obtained from Environmental Protection Agency's (EPA) IRIS database. The ISCT3 modeling performed by Cenex, for the HAPs identified above, demonstrated compliance with the negligible risk requirement.

**MAQP #1821-05** was issued to Cenex on September 3, 2000, to revamp its No. 1 Crude Unit in order to increase crude capacity, improve product quality, and enhance energy recovery. The project involved the replacement and upgrade of various heat exchangers, pumps, valves, towers, and other equipment. Only VOC emissions were affected by the new equipment. The capacity of the No. 1 Crude Unit was expected to increase by 10,000 or more barrels per stream day.

No increase in allowable emissions was sought under this permit application. The project would actually decrease VOC emissions from the No. 1 Crude Unit. However, increasing the capacity of the No. 1 Crude Unit was expected to increase the current utilization of other units throughout the refinery and thus possibly increase actual site-wide emissions, as compared to previous historical levels. Therefore, the permit included enforceable limits, requested by Cenex, on future site-wide emissions. The limits allow emission increases to remain below the applicable significant modification thresholds that trigger the NSR program for PSD and Nonattainment Area (NAA) permitting.

The site-wide limits were calculated based on the addition of the PSD/NAA significance level for each particular pollutant to the actual refinery emissions from April 1998, through March 2000, for SO<sub>2</sub>, NO<sub>x</sub>, CO, PM<sub>10</sub>, and particulate matter (PM) minus 0.1 TPY to remain below the significance level. A similar methodology was used for the VOC emissions cap, except that baseline data from the time period 1993 and 1999 were used to track creditable increases and decreases in emissions. The site-wide limits are listed in the following table.

Pollutant	Period Considered for Prior Actual Emissions	Average Emissions over 2-yr Period (TPY)	PSD/NAA Significance Level (TPY)	Proposed Emissions Cap (TPY)
SO <sub>2</sub>	April 1998-March 2000	2940.4	40	2980.3
NO <sub>x</sub>	April 1998-March 2000	959.5	40	999.4
CO	April 1998-March 2000	430.8	100	530.7
VOC	1993-1999	1927.6	40	1967.5
PM <sub>10</sub>	April 1998-March 2000	137.3	15	152.2
PM	April 1998-March 2000	137.3	25	162.2

For example, the SO<sub>2</sub> annual emissions cap was calculated as follows:

Average refinery-wide SO<sub>2</sub> emissions in the period of April 1998 through 2000 added to the PSD/NAA significance level for SO<sub>2</sub> minus 0.1 TPY =  
 2940.4 TPY + 40 TPY – 0.1 TPY = 2980.3 TPY = Annual emissions cap.  
 MAQP#1821-05 replaced MAQP #1821-04.

**MAQP #1821-06** was issued on April 26, 2001, for the installation and operation of eight temporary, portable Genertek reciprocating engine electricity generators and two accompanying distillate fuel storage tanks. Each generator is capable of generating approximately 2.5 megawatts of power. These generators are necessary because of the

high cost of electricity. The operation of the generators will not occur beyond two years and is not expected to last for an extended period of time, but rather only for the length of time necessary for Cenex to acquire a more economical supply of power.

Because these generators would only be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of these generators is minor. In addition, the installation of these generators qualifies as a “temporary source” under the PSD permitting program because the permit will limit the operation of these generators to a time period of less than 2 years. Therefore, Cenex would not need to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, the Department required compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 would be ensured. In addition, Cenex would be responsible for complying with all applicable air quality standards. In order to keep this permitting action below the threshold of nonattainment area permitting requirements, Cenex requested a limitation to keep the project’s potential emissions of SO<sub>2</sub> below 40 tons. MAQP #1821-06 replaced MAQP #1821-05.

**MAQP #1821-07** was issued on August 28, 2001, to change the wording regarding the stack height on the temporary generators, to allow for the installation of mufflers on those stacks, thus increasing the total stack height. In addition, the Department modified the permit to eliminate references to the repealed odor rule, to correct conditions improperly referencing the incinerator rule, and to update a testing frequency on the product loading rack VCU based on the Title V permit term. MAQP #1821-07 replaced MAQP #1821-06.

On June 3, 2002, the Department received a request from Cenex to modify MAQP #1821-07 to remove all references to 8 temporary, portable electricity generators. The generators were permitted under MAQP #1821-06, with further clarification added in MAQP #1821-07 regarding generator stack height. The generators have not been operated since August 10, 2001, and Cenex has no intention of operating them in the future. The references to the generators were removed, and the generators are no longer included in Cenex’s permitted equipment. **MAQP #1821-08** replaced MAQP #1821-07.

On March 13, 2003, the Department received a complete permit application from Cenex to modify MAQP #1821-08 to add a new Ultra Low Sulfur Diesel (ULSD) Unit, Hydrogen Plant, and associated equipment to meet the EPA’s 15 parts per million (ppm) sulfur standard for highway diesel fuel for 2006. The permit action removed the Middle Distillate Unifiner (MDU) charge heater, MDU stripper heater, MDU fugitives, and the #3 and #4 Unifier Compressors. The ULSD Unit included two heaters, four compressors, C-901 A/B and C-902 A/B, process drains, and fugitive piping components. The Hydrogen Plant included a single fired reformer heater, process drains, and fugitive piping components.

The treated stream from the ULSD Unit was separated into its constituent fuel blending products or into material needing further refining. The resulting stream was then stored in existing tanks and one new tank (128). Three existing tanks (73, 86, and 117) were converted to natural gas blanketed tanks to reduce emissions of VOCs from the ULSD Unit feed stock product streams. Cenex was to install a new TGTU for both the SRU #1 and #2 trains that will be operational prior to startup of the ULSD Unit but technically are not part of this permitting action. **MAQP #1821-09** replaced MAQP #1821-08.

On July 30, 2003, the Department received a complete application from CHS to modify MAQP #1821-09. The application was complete with the addition of modeling information provided to the Department on August 22, 2003. CHS requested to add a

new TGTU and associated equipment for Zone A's SRU #1 and SRU #2 trains to control and reduce SO<sub>2</sub> emissions from this source. CHS submitted modeling to the Department for a determination of a minimum stack height for the existing SRU #1 and SRU #2 tail gas incinerator stack. CHS also submitted a letter to the Department to change the name on the permit from Cenex to CHS. The permit action added the new TGTU, set a minimum stack height for the tail gas incinerator stack, and changed the name on the permit from Cenex to CHS. **MAQP #1821-10** replaced MAQP #1821-09.

On June 1, 2004, the Department received two applications from CHS to modify MAQP #1821-10. The applications were complete with the addition of requested information provided to the Department on June 16, 2004. In one application CHS requested to change the nomenclature for Reformer Heater H-801 to Reformer Heater H-1001. H-801 was previously permitted during the ULSD project (MAQP #1821-09), at 150-MMBtu/hr. CHS requested to change the size of Reformer Heater H-801 (H-1001) from 150-MMBtu/hr to 161.56-MMBtu/hr. In the other application CHS requested to increase the PAL for CO from 530.7 tons per year to 678.2 tons per year based on new information obtained by CHS. The new information was obtained after the installation of a CO continuous emission monitor (CEMS) on the FCCU Stack. Emissions of CO from the FCCU Stack were assumed to be zero until the installation of the CEMS. CHS also requested that specific emission limits, standards, and schedules required by the CHS Consent Decree be incorporated into the permit. **MAQP #1821-11** replaced MAQP #1821-10.

On December 15, 2004, the Department received a letter from CHS to amend MAQP #1821-11. The changes were administrative, primarily related to changing routine reporting requirements from a monthly basis to quarterly. The changes to the permit were made under the provisions of ARM 17.8.764, Administrative Amendment to Permit. **MAQP #1821-12** replaced MAQP #1821-11.

On March 28, 2006, the Department issued **MAQP #1821-13** to CHS to build a new 15,000-barrel per day (BPD) delayed coker unit and associated equipment. The new delayed coker unit allows CHS to increase gasoline and diesel production by 10-15% by processing heavy streams that formerly resulted in asphalt (asphalt production is expected to decrease by approximately 75%, but the capability to produce asphalt at current levels was maintained and no emission credits were taken with respect to any possible reduction in asphalt production) without increasing overall crude capacity at the refinery. The delayed coker unit produces 800 short tons per day of a solid petroleum coke product. To accommodate the downstream changes created by the new delayed coker unit, several other units will be modified including the Zone D FCC Feed Hydrotreater, FCCU, ULSD Unit, and Hydrofluoric Acid (HF) Alky Unit. Other units will be added: Delayed Coker SRU/TGTU/TGI, NHT Unit, NHT Charge Heater, Boiler No. 11, Light Products Railcar Loading Facility, and two new tanks will be added to the Tank Farm. Other units will be shut down: the Propane Deasphalting Unit, Unifiner Compressors No. 1 and 2, No. 2 Naphtha Unifier Charge Heater and Reboiler, BP2 Pitch Heater, and Boilers No. 3 and 4. The VCU associated with the new Light Products Railcar Loading Facility and the Coker Unit TGI were subject to and the requirements of 75-2-215, MCA and ARM 17.8.770, Additional Requirements for Incinerators. The Delayed Coker project and associated equipment modifications did not cause a net emission increase greater than significant levels and, therefore, does not require a New Source Review (NSR) analysis. The net emission changes were as follows:

Pollutant	Total Project PTE (TPY)	Contemporaneous Emission Changes (TPY)	Net Emissions Change (TPY)	PSD Significance Level (TPY)
NO <sub>x</sub>	39.2	-7.5	31.8	40
VOC	-1.5	-53.3	-54.8	40
CO	106.7	-23.2	83.5	100
SO <sub>2</sub>	39.7	0.0	39.7	40
PM	7.6	6.6	14.2	25
PM <sub>10</sub>	6.7	6.6	13.3	15

The following is a summary of the CO emissions included in the CO netting analysis: Coker project (+106.7 TPY), emergency generator (+0.44 TPY, start-up in 2002), Zone A TGTU project (+8.3 TPY, initial startup at end of 2004), and Ultra Low Sulfur Diesel project (-31.9 TPY, started up in 2005). MAQP #1821-13 replaced MAQP #1821-12.

On May 4, 2006, the Department received a complete application from CHS to incorporate the final design of three emission sources associated with the new 15,000 BPD delayed coker unit project permitted under MAQP #1821-13. The final design capacities have increased for the new NHT Charge Heater, the new Coker Charge Heater and the new Boiler No. 11. The application also includes a request to reduce the refinery-wide fuel oil burning SO<sub>2</sub> emission limitation. This reduction allows CHS to stay below the significance threshold for the applicability of the New Source Review-PSD program. The maximum firing rates are proposed to increase with the current permitting action. The following summarizes the originally permitted firing rates (MAQP #1821-13) and the new proposed firing rates for the heaters and the boiler:

NHT Charge Heater: 13.2 to 20.1 million British thermal units – Lower Heating Value per hour (MMBtu-LHV/hr) (22.1 million British thermal units – Higher Heating Value per hour (MMBtu-HHV/hr))

Coker Charge Heater: 129.3 to 146.2 MMBtu-LHV/hr (160.9 MMBtu-HHV/hr)

Boiler #11: 175.9 to 190.1 MMBtu-LHV/hr (209.1 MMBtu-HHV/hr)

CHS also requested several clarifications to the permit. Under MAQP #1821-13 several 12-month rolling limits were established for modified older equipment and limits for new equipment. CHS requested clarifications be included to determine when compliance would need to be demonstrated for these new limits. MAQP #1821-13 went final on March 28, 2006, and CHS is required to demonstrate compliance with the new limitations from this date forward. For the 12-month rolling limits proposed under MAQP #1821-13 and any changes to limitations under the current permit action, CHS would be required to demonstrate compliance on a monthly rolling basis calculated from March 28, 2006. For modified units the limitations will have zero emissions until modifications are made. New units will have zero emissions until start-up of these units. Start-up is defined as the time that the unit is combusting fuel, not after the start-up demonstration period. Some units have clearly designated compliance timeframes based on the consent decree. These limitations and associated time periods are listed within the permit.

The Department agreed that the heading to Section X.A.3 can include the “*Naptha Hydrotreating Unit*”; Section D.1.c is based on a 30-day rolling average; Section X.D.7.a.ii should state that the SO<sub>2</sub> limit is based on a 12-hour average; and that Section XI.E.3 should be revised to remove the requirement for a stack gas volumetric flow rate monitor. The Department made some clarifications to the language in Section X.D.6.b. The Department’s intent in permitting the coke pile with enclosures was to ensure that at no time would the coke pile be higher than the top of the enclosure walls at any point on the pile, not only the portion of the pile that is adjacent to the wall.

The Department did not believe it was necessary to designate the Sour Water Storage Tank as a 40 CFR 60, Subpart Kb applicable tank, when currently these regulations do not apply. If CHS makes changes in the future and 40 CFR 60, Subpart Kb becomes applicable to the tank, then CHS can notify the Department and the Department can include the change in the next permit action.

The Department received comments from CHS on the preliminary determination of MAQP #1821-14 on June 21, 2006. The comments were editorial in nature and the changes were made prior to issuance of the Department Determination on MAQP #1821-14. CHS requested corrections to the PM, PM<sub>10</sub>, NO<sub>x</sub> netting values in contained in the permit analysis, and the Department agreed that the edits were needed. CHS also requested further clarification to the requirements of Section X.D.6.b of the permit.

CHS stated that the coke pile will be dropped from two coke drums to a location directly adjacent to the highest walls of the enclosure area. The height of the dropped coke piles will not exceed the height of the wall. If CHS is required to relocate and temporarily store the coke at another location within the enclosure area, CHS will not pile the coke higher than the walls adjacent to the temporary storage location. **MAQP #1821-14** replaced MAQP #1821-13.

On September 11, 2006, the Department received an application from CHS to incorporate the final design of emission sources associated with the new 15,000-BPD delayed coker unit project permitted under MAQP #1821-13 and revised under MAQP #1821-14. The changes included:

- Retaining Boiler #4 operations and permanently shutting down the CO Boiler;
- Modifying the FCCU Regenerator CO limit due to the air grid replacement;
- Rescinding the permitted debottleneck project for Zone D SRU/TGTU/TGI and revising the long term SO<sub>2</sub> potential to emit;
- Modifying the Zone E (Delayed Coker) SRU/TGTU/TGI - Incinerator design and NO<sub>x</sub> limits;
- Rescinding the firing rate restriction and associated long-term emission limits, and revising VOC emission calculations for H-201 and H-202; and
- Removing the 99.9 MMBtu/hr restriction and reclassifying Boiler #10 as subject to NSPS Subpart Db.

On October 11, 2006, the Department received a request to temporarily stop review of the permit application until several additional proposals were submitted, which included:

- On October 24, 2006, the Department received a de minimis notification for stack design changes for the Delayed Coker Unit (Zone E) SRU Incinerator.
- On October 31, 2006, the Department received clarification on the ULSD project.
- On November 1, 2006, the Department received a request to limit the maximum heat rate capacity of the #2 N.U. Heater to below 40 MMBTU/hour in conformance with the CHS Consent Decree. CHS also requested that the Department re-initiate review of MAQP #1821-15.

All of the above changes allowed CHS to stay below the significance thresholds for the applicability of the New Source Review-PSD program. CHS also requested several clarifications to be included in the permit, and the Department suggested streamlining the permit's organization. **MAQP #1821-15** replaced MAQP #1821-14.

On October 10, 2007, the Department received an application from CHS to modify MAQP #1821-15 to incorporate the final design of the NHT Charge Heater. This heater was permitted as part of the refinery's delayed coker project permitted under MAQP #1821-13 and revised under MAQP #1821-14 and MAQP #1821-15. The modification to MAQP #1821-15 was requested to address an operating scenario that was overlooked during the delayed coker unit design process. This operating scenario is for the case in which the NHT unit is in operation, but the delayed coker unit is not. In this operating scenario, the characteristics of the naphtha being processed in the unit are such that additional heat input to the heater is required to achieve the design NHT Unit throughput. For this reason, CHS requested approval for an increase in the design firing rate of the NHT Charge Heater (H-8301). The following summarizes the permitted firing rates under MAQP #1821-15 and the new proposed firing rates for the NHT Charge Heater:

Maximum Firing Rate (LHV): 20.1 MMBtu-LHV/hr to 34.0 MMBtu-LHV/hr  
Maximum Firing Rate (HHV): 22.1 MMBtu-HHV/hr to 37.4 MMBtu-HHV/hr

This change does not impact any of the other design conditions in the original delayed coker permit, including unit throughputs and operating rates. The application also includes a request to reduce the refinery-wide fuel oil burning SO<sub>2</sub> emission limitation. This reduction allows CHS to stay below the significance thresholds for the applicability of the New Source Review-PSD program. CHS also requested some administrative changes to the permit. **MAQP #1821-16** replaced MAQP #1821-15.

On February 25, 2008, the Department received a complete application from CHS to modify MAQP #1821-16 for the completion of two separate projects. For the first project, CHS proposed to construct a new 209.1 MMBtu-HHV/hr steam generating boiler (Boiler #12). This project includes the permanent shutdown of two existing boilers, Boilers #4 and #5, which have a combined capacity of 190 MMBtu-LHV/hr. The two existing boilers are being shutdown in part to meet the consent decree NO<sub>x</sub> reduction requirements, as well as to generate NO<sub>x</sub> offsets for this permitting action.<sup>2</sup> Due to the operational complexity of replacing two existing boilers with one new boiler in the refinery steam system, CHS requested to maintain the ability to operate the #5 Boiler for 1 year after initial start-up of Boiler #12. Combustion of fuel oil in the refinery boilers would also be eliminated primarily to generate NO<sub>x</sub> offsets for this permitting action.

For the second project, CHS proposed an expansion of its railcar light product loading facilities. Although there would be no increase in refinery production from this expansion, the project would increase flexibility in the transportation of refinery products. After project completion, there would be a total of nine spots available at this loading rack for product loading into railcars. The railcar light product loading facility was originally permitted as part of the delayed coker project permitted under MAQP #1821-13 and revised under MAQP #1821-14, #1821-15, and #1821-16. This change does not require a modification to the originally permitted VCU since the maximum loading rate of 2,000 gallons per minute (gpm) will remain unchanged.

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<sup>2</sup> This is later clarified in the permit history for MAQP #1821-21. No creditable NO<sub>x</sub> emissions reductions from the shutdown of Boiler #4 and #5 were used in the permit for construction of new Boiler #12 (MAQP #1821-17).

The application also included a request to reduce the limitation for SO<sub>2</sub> emissions from the combustion of alkylation unit polymer and fuel oil in all combustion devices from 127.6 TPY to 50 TPY (for alkylation unit polymer only since fuel oil combustion in refinery boilers will be eliminated). Although the potential to emit for the combustion of alkylation unit polymer in the Alkylation Unit Hot Oil Heater is estimated to be around 8.3 TPY for SO<sub>2</sub> (based on a specific gravity of 0.7 and a sulfur content of 1 wt%; the exact potential to emit has not been determined due to the variability of specific gravity and sulfur content), the allowable emissions are set at 50 TPY in this permitting action. According to ARM 17.8.801(24)(f), the decrease in actual emissions from the elimination of fuel oil combustion in refinery boilers is creditable for PSD purposes provided the old level of actual emission or the old level of allowable emissions, *whichever is lower*, exceeds the new level of actual emissions and the decrease in emissions is federally enforceable at and after the time that actual construction begins. Since the old level of actual emissions is lower than the old level of allowable emissions for combustion of fuel oil in refinery boilers, CHS requested a creditable reduction based on actual emissions from the boilers. This reduction resulted in a total of 50 TPY SO<sub>2</sub> allowed for the combustion of alkylation unit polymer in the Alkylation Unit Hot Oil Heater, the only unit that is part of the original SO<sub>2</sub> limitation for fuel oil combustion devices that will continue to operate. While it appears that the emissions from the combustion of alkylation unit polymer would be allowed to increase through this permitting action, it is important to note that physical modifications and/or changes in the method of operation would first have to occur for the Alkylation Unit Hot Oil Heater to emit more than its estimated potential of 8.3 TPY (note: the exact potential to emit has not been determined at this time). As acknowledged by CHS, a modification and/or change in method of operation to this unit would require a permit modification. Therefore, the Department does not anticipate any increase in actual emissions from this unit, even though the allowable has been set at 50 TPY. In addition, should CHS eliminate or reduce the combustion of alkylation unit polymer in future permit actions in order to have a creditable decrease for PSD purposes, only the change in actual emissions would be available since the actual emissions will be lower than the allowable, unless a modification to the unit is made.

In addition, CHS requested that the permit CO emission limits for Boiler #11 be changed to 36.63 TPY and 15.26 lb/hr, based on a revised emission factor from performance test data completed in 2007 for Boiler #11 used to calculate the PTE. All of these changes allow CHS to stay below the significance thresholds for the applicability of the New Source Review-PSD program.

CHS also requested some additional administrative changes to the permit, including clarification of the applicability of 40 CFR 63, Subpart DDDDD: NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters to various sources given the fact that the federal rule was vacated on July 30, 2007. Although the federal rule has been vacated, the vacated federal rule remains incorporated by reference in ARM 17.8.103 and ARM 17.8.302 (with the applicable publication date specified in ARM 17.8.102) at the time of **MAQP #1821-17** issuance and as such, it remains an applicable requirement under state rules; each applicable permit condition has been marked 'State-Only Requirement'.

On April 1, 2008, CHS requested that the Department delay issuance of the preliminary determination for this permit application until additional information could be submitted regarding alternative coke handling practices. This additional information was submitted to the Department on April 3, 2008, with follow-up information received by the Department on April 14, 2008. CHS requested that an alternative coke handling process be included in MAQP #1821-17. The coke handling process, originally permitted as part

of the delayed coker project, included the use of conveyors to transport coke to a crusher and to a railcar loading system. Because the system is enclosed, it is not possible to transport coke to the crusher and loading system without the use of the conveyors. CHS has since identified the need for an alternate coke handling method to be used when the conveyors are out of operation for either planned or unplanned maintenance. MAQP #1821-17 replaced MAQP #1821-16.

On November 7, 2008, the Department received a MAQP application from CHS for a benzene reduction project. In this application, CHS requested to modify MAQP #1821-17, to allow construction of a new Benzene Reduction Unit within the Laurel refinery to meet the requirements of the Mobile Source Air Toxics Rule (40 CFR 80, Subpart L). This rule requires that the refinery's average gasoline benzene concentration in any annual averaging period not exceed 0.62 volume percent, beginning January 1, 2011. This new unit will be inserted in the middle of the existing Platformer Unit. The new process will receive feed from the high pressure separator of the existing Platformer unit and produce a heavy platformate stream that will go directly to product storage and a light platformate stream that will be treated further. The light platformate stream, concentrated with benzene, will undergo a benzene hydrogenation reaction to convert the benzene to cyclohexane. This stream will then be fed to the existing Platformer Unit's debutanizer.

Because the Benzene Reduction Unit includes a hydrogenation reaction, hydrogen is required for the process. For this reason, modification to the existing 1,000 Unit Hydrogen Plant is planned. This modification will essentially increase hydrogen production in the amount needed in the new process and includes the addition of a steam superheater and an Enhanced Heat Transfer Reformer (EHTR). In the existing process, hydrogen is produced by mixing natural gas and the hydrogen-rich Platformer Unit off gas stream with saturated steam. However, in the modified process, only natural gas will be used. Additionally, the steam used will be super-heated to supply additional heat to the primary reformer by means of a higher inlet process gas temperature. This modified process will allow for an increase in the process feed gas flow at the same reformer heat duty. As a result, more hydrogen will be produced in the reformer without increasing the firing rate, and thus, emission rate, of the H-1001 Reformer Heater. For this reason, the H-1001 Reformer Heater is not a project affected emission unit.

In this application, CHS also requested to make enforceable the retrofit of the Platformer Heater with low NO<sub>x</sub> burners. This modification is being done to achieve Consent Decree required NO<sub>x</sub> reductions. This modification is not required by the Benzene Reduction project; however, the retrofit of the Platformer Heater will occur during the construction phase of the Benzene Reduction project.<sup>3</sup>

The Department reviewed this application and deemed it incomplete on December 1, 2008. The Department requested additional information to support the BACT analysis for the Platformer Splitter Reboiler. The Department received the requested follow-up information from CHS on December 15, 2008; the application was deemed complete as of this date.

In addition to making the requested changes, the Department has clarified the permit language for the bulk loading rack VCU regarding the products that may be loaded in the event the VCU is inoperable and deleted all references to 40 CFR 63, Subpart DDDDD:

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<sup>3</sup>. The requirement to retrofit the Platformer Heater with low NO<sub>x</sub> burners was removed in MAQP #1821-21. CHS elected to achieve the Consent Decree required NO<sub>x</sub> reductions by using projects other than the Platformer Heater retrofit.

NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters, as it was removed from the ARM in October 2008. **MAQP #1821-18** replaced MAQP #1821-17.

On February 27, 2009, the Department received a complete MAQP application from CHS requesting clarification of an existing NO<sub>x</sub> emissions limit for Boiler #12. In this application, CHS requested that the averaging period for the NO<sub>x</sub> pound per million British thermal unit (lb/MMBtu) limit be specified as a 365-day rolling average. CHS submitted information to support this averaging period as the original basis for the BACT analysis conducted in MAQP #1821-17 for Boiler #12. **MAQP #1821-19** replaced MAQP #1821-18.

On August 13, 2009, the Department received a complete application from CHS requesting a modification to MAQP #1821-19. CHS proposed to retrofit the existing Boiler #10 with a lower NO<sub>x</sub> control technology burner and to update the permit limits for this unit accordingly. This project was completed on a voluntary basis by CHS in order to improve environmental performance and boiler reliability. On September 17, 2009, the Department received a revision to this application addressing the SO<sub>2</sub> BACT analysis for both Boiler #10 and the recently permitted Platformer Splitter Reboiler. This application revision was submitted in consultation with the Department and revised the SO<sub>2</sub> BACT analysis to reflect the recently finalized NSPS Subpart Ja requirements. **MAQP #1821-20** replaced MAQP #1821-19.

On March 31, 2010, the Department received an application from CHS requesting a modification to MAQP #1821-20. Additional information was received on April 22, 2010 resulting in a complete application. The application and additional information included requests for several modifications within the permit.

During the issuance of MAQP #1821-17, it became apparent that the Department and CHS had differing interpretations of paragraphs 177 and 180 of the CHS Consent Decree (CD) with EPA and the State of Montana (Consent Decree CV-03-153-BLG-RFC). Based on these differing interpretations, CHS deemed it necessary to retroactively analyze previous permit actions, particularly associated with the Delayed Coker Project, where changes may be necessary as a result of interpreting the CD in an alternative manner. On October 26, 2009, CHS provided an analysis concluding that the Delayed Coker Project was properly permitted as a non-major modification under New Source Review (including both PSD and Non-attainment Area New Source Review (NNSR)). For four pollutants (CO, VOC, TSP, and PM<sub>10</sub>), project related emissions increases determined under Step 1 of the required applicability analysis were below the applicable significance thresholds. For two pollutants (NO<sub>x</sub> and SO<sub>2</sub>), the net emissions change, including project related emissions increases and contemporaneous emissions changes, were below the applicability significance thresholds. Following review, the Department concurred with CHS' analysis. However, as a result of this re-examination, including updates and changes to the original Delayed Coker Project emissions calculations, the following updates to MAQP #1821-20 were necessary to accurately reflect the refinery's overall process and individual emitting units.

1. **Coke Drum Steam Vent**

The original Delayed Coker Permit application did not include an estimate of the emissions associated with depressurizing the coke drum as part of the decoking operation. Based on emissions quantified at another facility, CHS was able to estimate emissions from their Coke Drum Steam Vent. MAQP #1821-21 has been updated to include this emitting unit in addition to the limitations and conditions assigned to it.

2. FCCU Regenerator

As part of the CD requirements, CHS completed catalyst additive trials at the FCCU in order to reduce NO<sub>x</sub> emissions. Upon completion of the trials, CHS proposed short term (7-day rolling average) and long term (365-day rolling average) concentration-based NO<sub>x</sub> limits to EPA. CHS proposed a long term concentration limit of 65.1 parts per million, volumetric dry (ppm<sub>vd</sub>) on a 365-day rolling average basis and a short term concentration limit of 102 ppm<sub>vd</sub> on a 7-day rolling average basis. EPA has agreed to these proposed limitations and these limits have been included within MAQP #1821-21.

3. Boiler 12 and Railcar Light Product Loading Projects

Originally permitted within MAQP #1821-17, the Boiler 12 and Railcar Light Product Loading Projects were included in the same permit application for administrative convenience only and should not be included as part of the Delayed Coker Project's emissions increase calculations. The Department agrees that the two projects were not substantially related and had no apparent interconnection to each other or to the Delayed Coker Project. The emissions calculations have been updated to reflect this conclusion.

4. Shutdown Timing for #4 and #5 Boilers

Included in the permitting action resulting in MAQP #1821-17 were shutdown dates for Boiler #4 and Boiler #5, which was tied to the initial startup of Boiler #12. Because emissions reductions from the boiler shutdowns were not required to avoid triggering the PSD requirements, the shutdown dates are no longer related to the startup of Boiler #12. The timing is driven by the CD, requiring all NO<sub>x</sub> reduction projects (including shutdown of Boiler #4 and Boiler #5) to be completed by December 31, 2011. The shutdown timing has been updated.

5. Benzene Reduction Unit Project Updates

As a portion of the plan to achieve required NO<sub>x</sub> emissions reductions as outlined in the CD, CHS had elected to retrofit the Platformer Heater (P-HTR-1) with low NO<sub>x</sub> burners. The proposed retrofit was included in the application for the Benzene Reduction Project (MAQP #1821-18). CHS has determined that the retrofit will no longer be necessary to achieve the CD required NO<sub>x</sub> reductions. All emission limitation and monitoring, reporting and notification requirements were removed.

6. Boiler #11 and Boiler #12 BACT Analysis Update

The original BACT analyses included in the permit applications associated with Boiler #11 and Boiler #12 did not specifically address CO emissions during startup and shutdown operations. During these operations, the boiler may experience an increase in CO emissions as a result of the ultra low nitrogen oxide (NO<sub>x</sub>) burner (ULNB) design. Based on an analysis of data collected during startup and shutdown operations for Boiler #11 and Boiler #12, a short term CO limit of 23 lb/hr on a 24-hour average basis, was included for periods of boiler startup and shutdown. Additionally, CHS proposed installation and operation of a volumetric stack flow rate monitor on Boiler #11 in order to be consistent with Boilers #10 and #12.

In addition to the aforementioned updates, CHS also requested a modification to the stack testing requirements to require stack testing every 2 years as opposed to annual stack testing for the following sources: Reactor Charge Heater (H-201), Fractionator Feed Heater (H-202), Reactor Charge Heater (H-901), Fractionator Reboiler (H-902), and NHT Charge Heater (H-8301). The Department approved this new testing schedule and MAQP #1821-21 has been updated accordingly. Additionally, various miscellaneous administrative changes were requested and included in this permitting action. **MAQP #1821-21** replaced MAQP #1821-20.

On July 27, 2010, the Department received a request to administratively amend MAQP #1821-21. The Department had inadvertently failed to modify all pertinent sections within MAQP #1821-20 to reflect the December 31, 2011 shutdown date for Boiler #4 and Boiler #5. CHS had requested the Department to administratively amend the permit to reflect this shutdown date in all applicable sections within the permit. CHS also requested the Department administratively amend the permit to include a reference to ppm<sub>v,d</sub> units where H<sub>2</sub>S limits are expressed in grains per dry standard cubic feet (gr/dscf). The Department made the aforementioned administrative changes. **MAQP #1821-22** replaced MAQP #1821-21.

On November 1, 2010, the Department received an application from CHS requesting a modification to MAQP #1821-22.

#### “Mild Hydrocracker Project”

In this application, CHS proposed to convert the existing HDS Unit into a Mild Hydrocracker. Capacities of the existing 100 Unit Hydrogen Plant and the Zone D SRU/TGTU were proposed to be increased, the existing feed heater in the FCC Unit replaced and a rate-limiting pressure safety valve (PSV) in the NHT replaced. Collectively, these modifications are referred to as the “Mild Hydrocracker Project.” The primary purpose in converting the existing HDS Unit into a Mild Hydrocracker was to produce an increased volume of higher quality diesel fuel by utilizing more hydrogen to convert gasoil into diesel.

The Mild Hydrocracker Project consists of several components. Within the HDS, the following changes were slated:

- As a result of a significant increase in hydrogen consumption, modifications to the existing hydrogen supply and recycle system will be required. The existing C-201B gas-fired reciprocating engine and hydrogen recycle compressor will be replaced with an electric driven make-up hydrogen compressor. Additionally, a new electric-driven recycle compressor (C-203) will be added.
- The first two reactors will continue to contain a hydrotreating catalyst. The third reactor will be split from one bed of catalyst to two beds of catalyst, containing both hydrotreating and hydrocracking catalyst.
- Equipment to be added or modified as a result of volume or heat impacts include the following:
  - A hydrogen bypass line will be added to allow for hydrogen addition both upstream and downstream of the H-201 Reactor Charge Heater.
  - Changes in the separation process downstream of the reactors: Two new drums will be added, Hot and Cold Low Pressure Separators, along with additional heat exchange, including two sets of process heat exchangers, one cooling water heat exchanger and one fin-fan cooler.
  - Trays within the H<sub>2</sub>S Stripper will be replaced with higher capacity trays.

- The overhead condenser and pump associated with the H<sub>2</sub>S Stripper Overhead Drum will be modified.
- A new “wild” naphtha product draw will be added to the H<sub>2</sub>S Stripper Overhead Drum. This stream will be processed in the Crude Unit Naphtha Stabilizer and then routed to the NHT Unit.
- A bypass line for hydrocarbon feed to the Fractionator around the H-202 Fractionator Feed Heater may be added as a result of improved heat integration.
- The trays in the Fractionator will be replaced with higher capacity trays.
- A new flow loop on the Fractionator will be added returning a portion of the diesel draw to the Fractionator. The pump will also feed the Diesel Stripper. The loop will include a new pump, a fin-fan cooler and a steam generator.
- The trays in the existing Diesel Stripper will be replaced with higher capacity trays.
- New larger pump(s) will be added on the loop between the Diesel Stripper and the Diesel Reboiler. These pump(s) may also be used for diesel product.
- The Diesel Product Cooler (fin-fan) will be replaced with a higher capacity cooler.
- New higher capacity packing will be installed in the HP Absorber. Water circulation on the absorber will be eliminated.

Within the SRU, the following physical changes were proposed:

- Replace and upgrade the acid gas burner;
- Replace the reaction furnace and upgrade to higher pressure and temperature capability;
- Replace and upgrade the waste heat boiler for higher pressure steam generation;
- Replace and upgrade the three steam reheaters;
- Upgrade the #1 sulfur condenser; and
- Add new electric boiler feedwater pumps to accommodate the higher pressure steam generation.

Within the TGTU, the following physical changes were proposed:

- The trays in the quench tower and amine absorber will be replaced with higher vapor capacity trays;
- The cooling system will be improved through increased circulation and minor piping modifications to control the maximum temperature of the circulating amine; and
- The methyl diethanolamine amine (MDEA) used in the absorption section of the TGTU will be replaced with a proprietary high performance amine blend.

Within the 100 Unit Hydrogen Plant, the following changes were proposed:

- A new H-102 Reformer Heater will be added to operate in parallel with the existing H-101 Reformer Heater;
- Modification of existing BFW pumps for increased capacity and a new larger condensate cooler;
- Addition of new pumps to circulate water through the steam generation coil on the new reformer heater;
- Modification of the existing steam drum internals to handle higher steam loads;

- Replace end of life trays within the deaerator tower with higher capacity trays;
- Replace the hot and cold condensate drums with upgraded internals and more corrosion resistant metallurgy;
- Replace absorbent and valves on the PSA skid; and
- Remove equipment related to the use of propane as the feed stream to the 100 Unit Hydrogen Plant.

“FCCU Charge Heater-NEW”

CHS also proposed installation of a new FCCU Charge Heater (60 MMBtu-HHV/hr) to replace the existing FCC Charge Heater (FCC-Heater-1) that is near the end of its mechanical life. The new heater will be installed and started up on the same schedule as the conversion of the HDS Unit to a Mild Hydrocracker.

“ULSD Burner Fuel Project”

The application also included information related to an additional project that is proposed to be completed at the refinery concurrent with the project discussed above. The project involves adding the flexibility to recover additional Burner Fuel, rather than Diesel Fuel, within the existing ULSD unit. The feed rate to the ULSD Unit will not increase with this project. This project is referred to as the “ULSD Burner Fuel Project.”

In addition to the aforementioned projects, CHS requested the Department to incorporate several administrative changes.

**MAQP #1821-23** replaced MAQP #1821-22.

On January 10, 2011, the Department received a request to administratively amend MAQP #1821-23. In review of the Department Decision for MAQP #1821-23 issued on December 30, 2010, CHS identified areas within the permit that required further clarification based on their comments submitted on the Preliminary Determination issued for MAQP #1821-23.

**MAQP #1821-24** replaced MAQP #1821-23.

On April 12, 2011, the Department received an application from CHS for a modification to MAQP #1821-24. The modification request detailed proposed changes to a *de minimis* request approved by the Department on December 10, 2010 as well as proposed construction of two product storage tanks.

On December 6, 2010, the Department received a *de minimis* notification from CHS proposing construction of a new 100,000 barrel (bbl) storage tank (Tank 133) for the purpose of storing asphalt. Emissions increases as a result of the proposed project were calculated to be less than the *de minimis* threshold of 5 tpy, with no emissions from each of the regulated pollutants exceeding 1.44 tpy. Although CHS justified the project from an economics standpoint for asphalt service only, CHS determined that during the times of year that asphalt storage is not necessary, it would be advantageous to have the extra tank capacity available to store other materials, such as gas oil and diesel. These materials may accumulate in anticipation of or as a result of a unit shutdown. Within the April 12, 2011 application, CHS proposed installation of additional pumps and piping to allow for gas oil and diesel to be stored as well as asphalt as previously approved for Tank 133.

A separate project detailed within the April 12, 2011 application included construction of two new product storage tanks, collectively referred to as the Tanks 135 and 136 Project. The Tanks 135 and 136 Project included construction of two new 120,000 bbl external floating roof (EFR) product storage tanks and associated pumps and piping to allow more flexible storage of various gasoline and/or diesel components and finished products produced at the refinery. Tank 135 would be installed in the East Tank Farm located on the east side of Highway 212. With the current refinery piping configuration, this tank would store only finished gasoline and diesel products. Tank 136 would be installed in the South Tank Farm located on the west side of Highway 212. With the current refinery piping configuration, this tank would be available to store both component and finished gasoline and diesel products. To avoid restriction of service of the tanks, project emissions increase calculations were based conservatively on storage of gasoline year round as well as current maximum refinery production capability.

Within the April 12, 2011 application, CHS also provided supplemental information to the BACT analysis included in the original permitting application for the Coker Charge Heater (H-7501) originally permitted as a part of the Delayed Coker project (1821-13 with revisions 1821-14 through 1821-16). This supplemental information was submitted with the purpose of laying the foundation for a proposed additional short term CO emissions limit.

**MAQP #1821-25** replaced MAQP #1821-24.

On November 8, 2011, the Department of Department received an application from CHS for a modification to MAQP #1821-25. The application included three separate projects, grouped together into one action for administrative convenience. CHS proposed the following projects within this application:

1. #1 Crude Unit Revamp Project
2. Wastewater Facilities Project
3. Product Blending Project

The application also included the following:

1. Review of the regulatory applicability to existing Sour Water Storage Tanks 128 and 129.
2. Updates to the Mild Hydrocracker Project, which was permitted as part of MAQP #1821-23 and MAQP #1821-24.
3. Review of the regulatory applicability to the Product Storage Projects, which was permitted as part of MAQP #1821-25.

#### #1 Crude Unit Revamp Project

The #1 Crude Unit Revamp Project was proposed with the intention of improving the overall efficiency of the refinery by maximizing diesel and gas oil recovery in the atmospheric and vacuum processes at the #1 Crude Unit. The project would aid in accounting for changes in crude quality that have been evident historically and are expected in the future. Modifications in the vacuum process are expected to result in an improved separation of the diesel and gas oil components such that diesel will not be carried with the gasoil to units downstream of the Crude Unit. Modifications in the vacuum process will result in the recovery of additional gas oil from the asphalt and improved quality of feed to the downstream Delayed Coker Unit.

The #1 Crude Unit Revamp Project included the following key components:

- Improvements to the preheat exchanger trains to ensure additional heat can be added to the crude oil upstream of the atmospheric column.
- Modifications to the atmospheric column from the diesel draw downward and to the associated condensing systems.
- Existing dry vacuum process will be changed to a wet vacuum system through the addition of steam.
- Redesign and replacement of the existing vacuum column.
- Installation of new equipment to recover a diesel stream from the new vacuum column.
- Addition, replacement and/or redesign of overhead and product cooling systems.

#### Wastewater Facilities Project

The proposed Wastewater Facilities Project is slated to improve the overall performance of the refinery wastewater handling and treatment facilities and to address anticipated future wastewater discharge quality requirements. The project is comprised of the following components:

- Installation of new Three Phase Separator(s) to remove solids and free oil from wastewater generated at the crude unit desalters.
- Installation of new American Petroleum Institute (API) Separator(s) and Corrugated Plate Interceptor (CPI) Separator(s) to treat process wastewater generated at the older process units. The existing API Separator will be removed from service. As a note, emissions from the separators will be controlled with carbon canisters.
- Replacement of the existing activated sludge unit (ASU) (T-30). Replacement will be of the same size and will incorporate several design changes to improve the biological treatment efficiency.
- Installation of a second ASU and clarifier to be operated in parallel with the existing ASU and clarifier and will provide maintenance backup to the system.
- Installation of two new Sludge Handling Tanks to receive waste activated sludge from the clarifiers. The removed sludge will be dewatered and dried for offsite disposal.
- Installation of two new DAF Units to treat process wastewater from all of the process units. Emissions from the DAF Units will be controlled with carbon canisters. The existing DAF will be removed from service.

#### Product Blending Project

The objective of the Product Blending Project is to increase the volume of finished diesel and burner fuel available for sale. The project is comprised of the addition of new piping components; however, the changes will not result in a change to the operation of any process units at the refinery.

#### Additional Permit Changes

CHS conducted a review of regulatory applicability pertaining to sour water storage tanks 128 and 129, which were permitted as a result of CHS's permit application submitted on October 18, 2005, for the delayed coker project. Based on the review, CHS determined Tanks 128 and 129 to not be subject to 40 CFR 60 (NSPS) and also determined Tanks

128 and 129 to be labeled as Group 2 storage vessels as described within 40 CFR 63, Subpart CC. Therefore, CHS requested the permit, specifically the Title V Operating Permit, be updated to reflect these new determinations of regulatory applicability.

As part of MAQP #1821-23, CHS proposed to convert the existing Hydrodesulfurization (HDS) Unit into a Mild Hydrocracker. Since issuance of this permit, various portions of this project scope were modified, with only one change resulting in a change in the original project emissions calculations. Potential emissions increased slightly; however, continued to remain below significance levels with respect to Prevention of Significant Deterioration (PSD) review. A summary of the updated emissions inventory has been included in the permit analysis for this permit action.

CHS additionally conducted a review of regulatory applicability pertaining to Tanks 133, 135, and 136. As part of the original permitting action (MAQP #1821-25) associated with these product storage tanks, CHS identified the applicability of NSPS Subpart GGGa to the piping components associated with the three new storage tanks. This applicability has been reevaluated. NSPS Subpart GGGa applies to affected facilities at petroleum refineries that are constructed, reconstructed or modified after November 7, 2006. Specifically, as stated within NSPS Subpart GGGa, the group of all the equipment (defined in §60.591a) within a process unit is an affected facility. The definition of “process unit,” as defined in 60.590a(e) is as follows:

“*Process unit* means components assembled to produce intermediate or final products from petroleum, unfinished petroleum derivatives, or other intermediates; a process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the product.”

The applicability of NSPS Subpart GGGa has been determined to stop at the boundary of a process area and does not include piping components between the process area and storage tanks, therefore, eliminating the components associated with Tanks 133, 135, and 136 from being applicable to NSPS Subpart GGGa. Although this equipment is not specifically applicable under NSPS Subpart GGGa, the VOC BACT (Refinery Equipment) determination from MAQP #1821-25 stated that “an effective monitoring and maintenance program or Leak Detection and Repair (LDAR) program (as described under NSPS Subpart VVa) meeting the requirements of NSPS Subpart GGGa constitutes VOC BACT for equipment leaks from new components.” The Department has modified the requirements for institution of a monitoring and maintenance program to more accurately reflect the VOC BACT (Refinery Equipment) determination; thus removing the NSPS Subpart GGGa reference and including the pertinent language within the condition itself. The conditions are now reflective of only the BACT determination.

CHS also requested several various administrative changes and clarification additions.

**MAQP #1821-26** replaced MAQP #1821-25.

#### C. Current Permit Action

On June 4, 2012, CHS Inc. submitted a permit application to the Department to modify MAQP # 1821-26 and Title V Operating Permit (OP) # OP1821-10. The application is for modification to two previously permitted refinery projects, and to construct a new gasoline and diesel truck loading facility as summarized below:

#### “Mild Hydrocracker (MHC) Project Update”

This application includes the final design and location of the FCC Charge Heater-NEW being replaced as part of the MHC Project. The FCC Charge Heater was originally approved at 60 million British thermal units per hour (MMBtu/hr) as part of the MHC project (MAQP #1821-23). However, this permit application modifies the size of the heater from 60 to 66 MMBtu/hr. In addition, the permit application reclassifies the Fluid Catalytic Cracking Unit (FCCU) Reactor/Regenerator as a “modified” emitting unit and replaces the existing Riser with a new Riser (and Riser design), as the current Riser is nearing the end of its mechanical life. The Riser replacement incorporates a new design to improve temperature control in the process, minimize CO emissions and improve product yields.

#### “Benzene Reduction Unit (BRU) Project Update”

This project involves modification of the H-1001 Reformer Heater to achieve the design hydrogen production rate within the 1000 Unit Hydrogen Plant. Expansion of the 1000 Unit Hydrogen Plant was included in the MAQP #1821-18. However, the 1000 Unit Hydrogen Plant expansion changed the characteristics of the PSA tailgas (e.g. the heat content (British thermal units per standard cubic feet (Btu/scf) declined and the volume produced increased (standard cubic feet per minute (scfm))). According to CHS, the total heat input associated with the PSA tailgas remained nearly the same. As a result, the existing PSA tailgas burners on the H-1001 Reformer Heater could not handle the increased volume of PSA tailgas without excessive pressure drop and the 1000 Unit Hydrogen Plant production rate became limited by the volume of PSA tailgas that could be combusted. The proposed permit modification is to replace the PSA tailgas burner tips with tips that have larger ports such that all of the PSA tailgas that is generated can be combusted in the H-1001. CHS is also proposing to replace the supplemental fuel (e.g. natural gas, refinery fuel gas) burners in H-1001 to achieve improved NO<sub>x</sub> emission performance. The current heater is physically capable of combusting refinery fuel gas but cannot meet the existing NO<sub>x</sub> permit limits while doing so. Additionally, the modified heater will have a higher maximum design firing rate (191.8 MMBtu-*HHV*/hr post project versus 177.7 MMBtu-*HHV*/hr) and a slight increase in the actual firing rate is also expected.

#### “Gasoline and Distillate Truck Loading Facilities Project”

This permit application also proposes the construction of new gasoline and distillate truck loading facilities, including new storage tanks, loading rack and vapor combustion unit (VCU). The goal of the project is to improve safety and reduce truck congestion at the existing loading facility to be removed from service once the new one is constructed. The permit modification adds a new propane storage and loading facility. Additionally, CHS requested that the loading rack system (including the VCU and all associated tanks) be limited to 39.23 tons of VOCs per year to remain under the PSD significance threshold.

In addition to the three projects mentioned above, this permit action also includes miscellaneous updates and amendments. CHS requested to discontinue use of the SO<sub>2</sub> Continuous Emissions Monitoring System (CEMs) on the H-1001 stack because H-1001 is subject to 40 CFR 60, Subpart Ja which includes exemptions from hydrogen sulfide/sulfur dioxide (H<sub>2</sub>S/SO<sub>2</sub>) monitoring requirements for fuel gas streams that are inherently low in sulfur content. The primary fuel to H-1001, PSA tailgas, is inherently low in sulfur content. CHS already monitors the H<sub>2</sub>S content of the refinery fuel gas (RFG) to be combusted in H-1001 as supplemental fuel, which would meet the monitoring requirements of Subpart Ja.

CHS requested that the Department remove condition IV.E.4 which requires the use of statistically significant F-factor values in determining compliance with NO<sub>x</sub> and CO limits for the H-102 Reformer Heater. Rather, CHS proposes that results of the required performance testing be used to calculate an appropriate emission factor to demonstrate ongoing compliance with NO<sub>x</sub> and CO limits.

D. Process Description – Permitted Equipment

**HDS Complex** - CHS constructed a new desulfurization complex within the existing refinery to desulfurize the gas-oil streams from the crude, vacuum, and the propane deasphalting units in 1992. The HDS unit removes sulfur from the gas-oil feedstock before further processing by the existing FCC unit. The new HDS unit greatly reduces the sulfur content of the FCCU feeds and, thereby, reduces the regenerator sulfur oxide emissions. Sulfur oxide emissions from the FCCU occur when coke-sulfur is burned off the catalyst at the unit's regenerator. Also, the FCCU clarified oil will contain a much lower sulfur content due to the HDS unit. FCCU clarified oil, when burned throughout the refinery in various furnaces and boilers, will result in lower sulfur oxide emissions. By removing sulfur compounds from the gas-oil and other FCCU feedstocks, the HDS process effectively reduces the sulfur content of refinery finished products, such as gasoline, kerosene, and diesel fuel. Lower sulfur content in gasoline and diesel fuels results in lower sulfur oxide emissions to the atmosphere from combustion by motor vehicle engines.

Additionally, the desulfurization complex includes other process units, such as the SWS, amine, SRU, and the TGTU. The new Hydrogen Plant and new HDS unit make up the new desulfurization complex for the refinery.

CHS filed a petition for declaratory judgment, which was granted by district court, which affords confidentiality protection on all HDS process and material rates, unit and equipment capacities, and other information relating to production. These are declared to be trade secrets and are not part of the public record. Hence, the reason for not providing the barrels-per-stream-day (BPSD) capacity of the new HDS unit and other new units, save the SRU, considered in this permit application analysis.

**Hydrogen Plant** - This unit produces pure hydrogen from propane/natural gas and recycled hydrocarbon from the hydrodesulfurizer, which, in turn, is used in the HDS unit. The feed is first purified of sulfur and halide compounds by conversion over a cobalt/molybdenum catalyst and subsequent absorption removal. The purified hydrocarbon is mixed with steam and the whole stream is reformed over a nickel catalyst to produce hydrogen (H<sub>2</sub>), CO, carbon dioxide (CO<sub>2</sub>), and methane (CH<sub>4</sub>). The CO is converted to CO<sub>2</sub> over an iron oxide catalyst and the total gas stream cooled and finally purified by a solid absorbent in a fixed bed or Pressure Swing Adsorption unit (PSA), (hydrogen purification unit).

The reformer heater (H-101) is utilized by the Hydrogen Plant. The design heat input rate is 123.2 MMBtu/hr; however, CHS has determined that heat inputs of up to 135.5 MMBtu/hr are necessary for short periods of time. This heater burns a combination of natural/refinery gas and recovered PSA gas. PSA gas (374Mscf/hr) supplies 85% (104.7 MMBtu/hr) of the necessary fuel requirement. The remaining 15% (18.5 MMBtu/hr) fuel requirement is supplied by natural/refinery gas (19.3Mscf/hr).

**HDS Unit** – A feed blend of preheated gas oils/light cycle oils from various crude units are filtered and dewatered. The feed is further heated by the reactor charge heater (H-201) and combined with a stream of hydrogen-rich treat gas and charged to the first of three possible reactors. Only two reactors (first and second) are installed and a third reactor may be added in the future. The reactors contain one or more proprietary hydro-

treating catalysts, which convert combined sulfur and nitrogen in the feed into hydrogen sulfide ( $H_2S$ ) and ammonia ( $NH_3$ ). Effluent off the reactor flows to a hot high-pressure separator where the vapor and liquid phases separate. The vapor/liquid stream then enters the cold high-pressure separator where the phases separate. Liquid water separates from the liquid hydrocarbon phase and collects in the boot of the vessel where vapor separates from the liquids. The vapor stream from the cold high-pressure separator flows to the high-pressure absorber, where it is contacted with amine solution to remove  $H_2S$ . The vapor stream is then subjected to a water wash to remove entrained amine. Amine, rich in  $H_2S$ , is pressured from the bottom of the absorber to the amine regeneration unit. The scrubbed and washed gas leaves the top of the high-pressure absorber and passes to the recycle cylinders of the make-up/recycle gas compressors. A portion of the discharge gas from these compressor cylinders is used as quench to control the inlet temperatures of the second reactor (and possibly a third reactor in the future).

$H_2$  from the Hydrogen Plant flows into the make-up/recycle gas unit section. The  $H_2$  is compressed in the two-stage make-up cylinders of the make-up/recycle gas compressors and then mixed with the recycle gas stream. The combined gas (treat gas) recovers heat from the hot high-pressure separator and is then injected into the preheated oil feed at the inlet of the heat recovery exchangers.

In the fractionation section of the HDS unit, hot liquid from the hot high-pressure separator is mixed with cold liquid from the cold high-pressure separator and the combined stream is flashed into the  $H_2S$  stripper tower. The heat in the tower feed and steam stripping separates an off-gas product from the feed with essentially complete removal of  $H_2S$  from the bottom product. This off-gas product leaves the  $H_2S$  stripper overhead drum and flows to the amine unit for recovery of sulfur. The bottom product from the  $H_2S$  stripper is heated in the fractionator feed heater (H-202) and is charged to the flash zone of the fractionator. In the fractionator tower and associated diesel stripper tower,  $H_2S$  stripper bottoms are separated into a naphtha overhead product, a diesel stripper stream product, and a bottom product of FCC feed. Separation is achieved by heat in the feed, steam stripping of the bottom product, and reboiling of the diesel product.

The naphtha product is pumped from the fractionator overhead drum to intermediate storage. The diesel and bottoms desulfurized gas-oil (FCC feed) products are also pumped to intermediate storage. A new wash water and sour water system will accompany the reaction/separation section of the HDS unit. Water is pumped from the wash water surge tank and injected into the inlet of the high-pressure separator vapor condenser to remove salts and into the high-pressure absorber circulating water system to remove amine. Water injected to the hot high-pressure separator vapor condenser produces sour water, which accumulates in the water boot of the cold/high-pressure separator. This sour water is pressured to the sour water flash drum. Additional sour water is produced from stripping steam and heater injection steam and accumulates in the water boots of the  $H_2S$  stripper overhead drum and the fractionator overhead drum. Other accumulations from sour water sources, such as knock-out drums, are also sent up to the sour water flash drum. The sour water is pressured from the sour water flash drum and sent to the sour water storage tank.

A reactor charge heater (H-201) and fractionator feed heater (H-202) is utilized by the HDS unit. H-201 design heat input rate is 37.7 MMBtu/hr. Once the HDS reactors are at operating temperature, the process is exothermic. As a result, H-201 firing rates are reduced. For purposes of this application, the worst case assumption is made that H-201 always operates at 80% for design (30.2 MMBtu/hr and 31.2 Mscf/hr). H-202 heat input design rate is 27.2 MMBtu/hr. Similar to H-201, once the HDS reactors are at operating

temperature, the process is exothermic and produces sufficient heat to sustain the reaction temperature. Excess heat is recovered and transferred to the fractionator feed which reduces the need for the fractionator feed heater. For purposes of this application, the worst case assumption is made that H-202 operates at 75% of full design capacity (20.4 MMBtu/hr and 21.3 Mscf/hr).

**Amine Unit** - A solution of amine (nitrogen-containing organic compounds) in water removes H<sub>2</sub>S from two refinery gas streams. The new amine unit will not process sour refinery fuel gas since this operation is to be handled by the existing refinery amine unit, except for amine unit start-up operations.

Amine temperature is controlled to assure that no hydrocarbon condensation occurs in the absorber tower. A large flash tank with a charcoal filter is used to remove any dissolved hydrocarbons. The flash vapor flows to the TGTU for sulfur recovery. Also from the flash tank, the rich amine flows through the rich/lean exchanger where it is heated and sent to the still regenerator. The regenerator is heat controlled. The clean amine level is controlled and the amine cooler stream is sent to a surge tank with a gas blanket. Lean low-pressure and high-pressure streams are pumped from the surge tank to their respective contactors. H<sub>2</sub>S in the overhead gas from the amine still accumulator are directed to the new SRU.

**Sour Water Stripper** - A new SWS was constructed, which replaced the operation of the older existing SWS. The new SWS unit serves the existing and proposed facilities of this HDS project. The old SWS cannot be removed, however, and functions only as the back-up unit. Sour water from a variety of sources in the refinery is accumulated in the sour water storage tank where hydrocarbons are separated. The hydrocarbon is sent to the existing slop oil system for recovery. The gas vapors from the sour water tank are compressed and sent to the tail gas unit for sulfur recovery. Sour water from the storage tank is pumped into the SWS tower. Steam heat is applied to the stripper to remove H<sub>2</sub>S and NH<sub>3</sub> from the water. The stripper overhead gas containing H<sub>2</sub>S and NH<sub>3</sub> is sent to the new SRU for sulfur recovery and incineration of NH<sub>3</sub>.

**Sulfur Recovery Plant** - The SRU is designed as a dual operation facility. The SRU has two different modes of operation.

Mode I - Standard Straight Through Operation is where the unit operates as a standard three-bed Claus unit. The Claus operation consists of a sulfur reaction furnace designed to sufficiently burn (oxidize) incoming acid gas (H<sub>2</sub>S) to SO<sub>2</sub>, to form water vapor and elemental sulfur. SO<sub>2</sub> further reacts with H<sub>2</sub>S to form more sulfur and water vapor. This is accomplished over three sulfur reactor catalyst beds and four condensers. Following the final reactor and condensing phase, the tail gas from the SRU is directed to the TGTU where additional sulfur treating occurs to further enhance recovery.

The new SRU has a design input rate of 79.18 short tons of sulfur per day (70.69 long ton/day) from three refinery feed streams. The overall efficiency of Mode I operation is 97.0%. This figure does not include additional sulfur recovery at the TGTU. Mode II - Sub-Dew Point Operation utilizes the same Claus reaction and front-end operation, except the second and third catalyst beds are alternated as sub-dew point reactors. The gas flow is switched between the two beds. When a bed is in the last position, the inlet temperature is lowered, which allows further completion of the H<sub>2</sub>S-SO<sub>2</sub> reaction and, thereby, recovering more sulfur. The sulfur produced condenses, due to the lower temperature, and is absorbed by the catalyst. After 24 hours of absorbing sulfur, the switching valve directs the gas flow from the third reactor to the second reactor and from reactor #2 to reactor #3. The cold bed is then heated by being diverted to the hot position

and all the absorbed sulfur is vaporized off, condensed and collected. The former hot bed is then cooled and utilized as the sub-dew point reactor for a period of 24 hours. The system cycles on a daily basis. The overall efficiency of Mode II operation is 98.24%. This figure does not include additional sulfur recovery at the TGTU. The advantage to two different modes of operation is for those times when the TGTU is not operating. The final heater (E-407) is used during the standard Claus unit operation; but, during the sub-dew point mode, it is blocked to prevent sulfur accumulation.

**Tail Gas Treating Unit** - The TGTU converts all sulfur compounds to  $H_2S$  so they can be removed and recycled back to the SRU for reprocessing. This process is accomplished by catalytically hydrogenating the Claus unit effluent in a reactor bed. From the reactor, the vapor is cooled in a quench tower before entering the unit's amine contactor. The hot vapors enter the bottom of the quench tower and contact water coming down the tower. The water is sent through a cooler exchanger and recycled in the tower. Excess water is drawn off and sent to the new sour water storage system. The cooled-off gas enters the bottom of the unit's amine contactor where  $H_2S$  is removed prior to final incineration. The TGTU's amine contactor and regeneration system are separate from the other two amine units previously mentioned. This design prevents cross-contamination of amine solutions. The off-gas from the TGTU amine contactor containing residual  $H_2S$  is sent to the sulfur plant incinerator. The concentrated  $H_2S$  stream is directed to the SRU sulfur reaction furnace, which converts the  $H_2S$  to  $SO_2$ , which recycles through the Claus process. The efficiency of the TGTU for sulfur removal is 99.46%. The TGTU adds additional sulfur recovery efficiency to the sulfur plant. The overall efficiency for sulfur removal for the SRU, plus TGTU, is 99.96%.

The sulfur plant incinerator (INC-401) is designed to burn any  $H_2S$  and other substances that make it past the SRU and TGTU. Also, exhaust gas from reheater E-407 (operated during Mode I) at the SRU is vented to the sulfur plant incinerator. The design heat input rate for reheater E-407 is 1.0 MMBtu/hr and is fired by natural/refinery gas. The design heat input rate for INC-401 is 3.8 MMBtu/hr. Therefore, these two fuel-burning devices, together, will fire a potential 5.0 Mscf/hr of fuel gas (4.8 total MMBtu/hr).

The overhead gas ( $H_2S$ ,  $NH_3$ ) from the SWS unit is treated by the SRU. SWS gas from the existing unit is currently incinerated at the FCC-CO boiler and results in significant emissions of  $SO_2$  and  $NO_x$ . This refinery activity and resultant emissions will cease, contemporaneously, with the new HDS operation. Also, the sulfur feed to the existing refinery Claus SRU will be greatly diminished. This should result in significant  $SO_2$  emission reductions, which have not been quantified.

**Ultra Low Sulfur Diesel Unit and Hydrogen Plant** – The ULSD Unit was designed to meet the new sulfur standards for highway diesel fuel as mandated through the national sulfur control program in 40 CFR Parts 69, 80, and 86. CHS shut down the existing MDU and replaced it with the ULSD Unit, to produce ultra low sulfur diesel and other fuels. At installation, the ULSD Unit was designed to handle the existing MDU process feeds of 21,000 bpd including; raw diesel from #1 and #2 Crude Units, hydrotreated diesel from the Gas Oil Hydrotreater, light cycle oil from the FCCU, and burner fuel from the #1 and #2 Crude Units. The feed streams are processed into several product streams; finished diesel, finished #1 burner fuel, and raw naphtha. After the delayed Coker project in 2007, the available feed processed by the ULSD unit is expected to increase to 24,000 bpd.

These products are stored in existing tanks dedicated to similar products from the MDU. Seven storage tanks were modified as a result of the original ULSD Unit project.

CHS's existing Hydrogen Plant and the proposed Hydrogen Plant would supply hydrogen for hydrotreatment. These units catalytically reform a heated propane/natural gas and steam mixture into hydrogen and carbon dioxide then purify the hydrogen steam for use in the ULSD Unit. Existing plant sources also supply steam and amine for the ULSD Unit.

Sour water produced in the ULSD Unit will be managed by existing equipment, including a sour water storage tank and a sour water stripper that vents to SRU #400. Fuel gas produced in the unit will be treated and distributed within the plant fuel gas system. Oily process wastewater and storm water from process areas managed in existing systems will be treated in the existing plant wastewater treatment plant.

**Zone A's TGTU for SRU #1 and #2 Trains** - The SRUs convert H<sub>2</sub>S from various units within the refinery into molten elemental sulfur. The SRU process consists of two parallel trains (SRU #1 and SRU #2 trains) that each include thermal and catalytic sections that convert the H<sub>2</sub>S and SO<sub>2</sub> into sulfur. In each train, the process gas exits the catalytic reactors and enters a condenser where sulfur is recovered and is gravity fed into the sulfur pits. Process gas from the condensers is then sent to the TGTU for additional sulfur removal. The TGTU is an amine-type H<sub>2</sub>S recovery and recycle TGTU. The TGTU utilizes an in-line tail gas heater (TGTU-AUX-1), which also generates hydrogen from reducing gases that reduce the SO<sub>2</sub> in the tail gas to H<sub>2</sub>S. After passing through the quench tower, the stream enters an amine absorber where H<sub>2</sub>S is selectively absorbed. The off-gas passes to the SRU-AUX-4, where it is incinerated to convert remaining H<sub>2</sub>S to SO<sub>2</sub> before venting to atmosphere. The rich amine leaving the absorber is regenerated in the tail gas regenerator, and the H<sub>2</sub>S recovered is routed back to the front of the SRU unit. The lean amine is routed to a new MDEA surge tank (TGTU-VSSL-6). The efficiency of the TGTU for sulfur removal is 98.93%. The TGTU adds additional sulfur recovery efficiency to the sulfur plant. The overall efficiency for sulfur removal for the SRU, plus TGTU, plus the SRU-AUX-4, is nearly 100%.

The SRU-AUX-4 is designed to burn any H<sub>2</sub>S and other substances that make it past the SRU and TGTU. Also, exhaust gas from the SRU-AUX-1 is vented to SRU-AUX-4. The design heat input rate for TGTU-AUX-1 is 4.17 MMBtu/hr and the unit is fired by natural/refinery fuel gas. The design heat input rate for SRU-AUX-4 is 10.85 MMBtu/hr and the unit is fired on refinery fuel gas. Therefore, these two fuel-burning devices, together, will potentially use 18.55 Mscf/hr of natural and refinery fuel gas (15.02 total MMBtu/hr).

**Delayed Coker Unit** – The delayed coker unit is designed to process 15,000 bpd of a residual asphalt stream (crude vacuum distillation bottoms). Through the delayed coking process, the unit will produce 800 short tons per day of a solid petroleum coke product and various quantities of other liquid and gaseous petroleum fractions that will be further processed in other refinery units. When integrated into other refinery operations, it is expected that the coker will result in an approximate 75% decrease in asphalt production and a 10-15% increase in gasoline and diesel production. Although the delayed coker project and other projects described in Permit Application #1821-13 will result in a shift in the type of products that will be made at the refinery, there will not be a change to the refinery's 58,000 bpd capacity, and actual crude processing rates are not expected to increase.

Some of the major equipment items in the delayed coker unit include: a new 160.9 MMBtu-high heating value (HHV)/hr Coker Charge Heater (H-7501), a new Coke Storage Area and Solids Handling Equipment to store and transfer the 800 short tons per day of coke product to rail cars for shipment; a new Coker Flare used exclusively to

control emissions during start-up, shutdown, and malfunctions (no continuous vents will be flared); and a new coker amine unit and a Zone E (previously called Coker) SRU/TGTU/TGI, which is designed to process 70.6 long tons per day of sulfur. There will be emissions from a Coker Unit Oily Water Sewer and Cooling Tower.

E. Response to Public Comments

Person/Group Commenting	Permit Reference	Comment	Department Response
CHS	Permit Analysis	CHS commented on several administrative corrections	The Department has made the requested changes to the permit.
CHS	Section I.B.	CHS suggested a modification to the second sentence in the truck loading project description. CHS requested the Department remove "...at the existing loading facility to be removed from service once the new one is constructed..." and change this to "The goal of the project is to improve safety and reduce truck traffic congestion by relocating the gasoline and distillate truck loading operation to the east side of Highway 212."	The Department made this change and added further clarification.
CHS	Section VI and XVI	CHS requested that the Department remove references to storage tanks in Section VI (Truck Loading Rack (s) and VCU(s)) and move all tank requirements to Section XVI (Product Storage Tanks).	The Department agrees with many of the changes. As such, the Department removed most references to storage tanks in Section VI as the limits for tanks are covered in Section XVI. However, the Department retained the VOC permit limit found in Sections VI.C.1 and XVI.C.6 which are identical limits. The Department believes both are necessary to ensure compliance with the requested federally enforceable limit of 39.23 TPY.
CHS	40 CFR 63, Subpart R	In the application, CHS previously identified that the new tank loading rack would be subject to 40 CFR 63, Subpart CC and 40 CFR 63, Subpart R. However, CHS reevaluated the applicability and determined that the refinery is subject to 40 CFR 63, Subpart CC. CHS did recognize that Subpart CC references many of the requirements of Subpart R but overall compliance is with Subpart CC.	The Department agrees and removed all references to 40 CFR 63, Subpart R.
CHS	VI.A.i	CHS recommended modifying this condition to require the stack for the new VCU to be "at least" 40 feet above grade.	The Department agrees and modified the condition as such.
CHS	VI.B.2	CHS requested that the Department remove references to 40 CFR 60, Subpart Kb from this section as this will be covered in Section XVI.	The Department agrees with this change.
CHS	VI.C.1	CHS commented that the permit contains a combined VOC emission limit for all facilities relating to the new truck loading rack and associated tanks	The Department retained the permit limits in Section VI.C.1 and XVI.C.6 which are identical limits. The Department modified both conditions to

		(XVI and VI). However, to avoid duplication of this limit, CHS requested that the limit be only in Section XVI and modified language to VI.C.1 as follows: “As part of MAQP 1821-27 for new gasoline and distillate truck loading facilities, a combined VOC emission limit was established. The limit which includes emissions from the new loading rack, VCU, associated storage tanks and fugitive sources, is found at Section XVI.C.6.”	include fugitives; however, the Department believes that although the conditions are identical they are necessary to ensure compliance with the requested enforceable permit limit of 39.23 TPY. Once the new loading rack and associated equipment start operation and the existing loading rack and associated equipment are permanently removed from service, the Department and CHS can reevaluate this.
CHS	VI.C.2 and VI.C.3.a	CHS had two comments associated with this section. The first was to remove reference to 40 CFR 63, Subpart R and the second was to delete VI.C.2 as it appears to be duplicated but add the 40 CFR 63, Subpart CC regulatory reference to VI.C.3.	The Department agrees and has made the appropriate changes.
CHS	VI.D	CHS requested that the Department add an LDAR condition to VI.D for the new truck loading facility.	The Department agrees and added this requirement.
CHS	VI.G.1.a and b	CHS commented: “to avoid duplication of permit conditions, CHS proposes that these notification requirements only reference the start of construction and actual startup of the new Truck Loading rack and VCU”.	The Department removed reference to the storage tanks in the notification requirement.
CHS	VI.G.1.c	CHS requested that they be allowed 180 days (rather than 30 days) to transition from the existing gasoline and distillate truck loading facility to the new loading facility.  Additionally, CHS commented that they do not intent to physically remove the existing loading rack and associated equipment within 180 days but will permanently remove it from service within 180 days. CHS offered to notify the Department within 30 days from the date the existing loading facility is permanently removed from service.	The Department changed the notification requirement and will allow 180 days rather than 30 days for permanent removal from service the existing loading rack and associated equipment.  The Department had been under the impression that the equipment would be physically removed. In light of this information, the Department added the following condition: “Within 180 days from startup of the new loading rack(s) and associated equipment, CHS shall provide documentation demonstrating that the existing truck loading rack, existing propane loading rack and the existing VCU have all been rendered inoperable.”
CHS	XVI	CHS requested that this section be titled “Limitations and Conditions for Storage Tanks (Tanks 135-143 and Additive Tanks)”.	The Department has made the suggested change.
CHS	XVI.B.4	CHS suggested (to avoid duplication) that all conditions relating to the new truck loading rack be contained in Section VI of the permit and recommends deleting this condition.	The Department deleted references to 40 CFR 63, Subpart R.
CHS	XVI.C.4	CHS provided two comments which are summarized as:	The Department agrees and has made the appropriate changes.

		<p>1) CHS did not complete a BACT analysis on the additive tanks because the emissions were less than 0.25 tpy per tank. Therefore, ARM17.8.752 would not apply to the additive tanks. CHS believes this condition should only apply to Tank #139.</p> <p>2) CHS stated that only #1 and #2 diesel fuel will be stored in Tank 139 and therefore this tank is not subject to 40 CFR 60, Subpart Kb.</p>	
CHS	XVI.C.5	<p>CHS suggested the following modification to this condition for clarity: “Until the new loading rack and associated equipment <b>being installed as part of MAQP 1821-27</b> are <b>operational</b>, the combined VOC emissions from the Storage tanks 135 and 136 shall not exceed 12.6 tons/rolling 12-calendar month total. This limit includes emissions while the roofs are floating and emissions during time periods that the tank roofs are landed on the legs. <b>This permit condition will no longer apply after the new loading rack and associated equipment being installed as part of MAQP #1821-27 are operational.</b></p>	<p>The Department modified this condition slightly. The Department refrained from listing the MAQP #1821-27 in each condition as this quickly becomes outdated with each new permitting action. The Department agrees that this condition will no longer apply once the new loading rack and associated equipment are operational, however, the Department would suggest amending the permit once the project is complete.</p>
CHS	XVI.C.6	<p>CHS suggested the following modification to this condition for clarity: “Once the new loading rack and associated equipment being installed as part of <b>MAQP 1821-27</b> are <b>operational</b>, the annual combined total VOC emissions shall not exceed 39.23 tpy based on a rolling 12-calendar month total. <b>This limit includes all emissions relating to the operation of the truck loading facilities and associated VCU, Tanks 136-143, Additive Tanks 1-4 and all associated fugitive sources.</b>”</p>	<p>The Department modified this condition slightly but retained the permit limits in Section VI.C.1 and XVI.C.6. The Department modified both conditions to include some suggested language and added fugitives. However, the Department believes that although the conditions are identical they are necessary to ensure compliance with the requested enforceable permit limit of 39.23 TPY.</p> <p>The Department refrained from listing the MAQP #1821-27 in each condition as this quickly becomes outdated with a new permit action.</p> <p>Once the new loading rack and associated equipment start operation and the existing loading rack and associated equipment are permanently removed from service, the Department and CHS can reevaluate this.</p>
CHS	XVI.D.1	<p>CHS requested that the Department modify the condition to include Tanks 135-139 and 142-143 rather than simply referring to storage tanks. CHS did not include the additive tanks in this condition because the actual emissions are less than 0.25 tpy each and did not include the propane tanks</p>	<p>The Department modified this condition. However, the Department did not remove the Additive tanks because they are necessary to demonstrate on-going compliance with the emission limits contained in XVI.C.6 and VI.C.1.</p>

		because they are pressurized vessels that will have no inservice emissions. CHS commented that running TANKS model for each of the additive tanks on a monthly basis is excessive and instead proposes to estimate the emissions based on the ratio of actual additive throughput compared to the throughput used in determining the PTE for each tank.	
CHS	XVI.D.2	CHS suggested the Department reword this condition as follows for clarity: "CHS shall document, by month the total VOC emissions from the new loading rack and associated equipment being installed as part of MAQP #1821-27. This includes all emissions relating to the operation of the truck loading facilities and associated VCU, Tanks 135-143, Additive Tanks 1-4 and all associated fugitive sources. This must also include emissions while the roof of the IFR and EFR tanks are floating and emissions during time periods that the tank roofs are landed on the legs. The monthly information shall be used to verify compliance with the rolling 12-month limitations in Section XVI.C.6.	The Department modified this condition to include some of the suggested language.
CHS	XVI.E.1 and 2	Condition E.1 and XVI.D.2 appears to be the same. CHS suggested that E.1 be deleted and that XVI.E.2 be revised as follows: "...The quarterly report shall include the 12-month rolling total VOC emissions by month, to document the compliance status of the limitation in Section XVI.C.5 and XVI.C.6, as applicable."	The Department deleted the section formally listed as XVI.E.1, modified XVI.D.2 and modified the section previously listed as XVI.E.2.
CHS	XVI.F	CHS has already met the notification requirements for Tanks 135 and 136. CHS suggested the Department modify the condition to "...written notification of the actual startup date of Storage Tanks 137-143; Additive Tanks 1-4; within 15 days after the actual start-up date of each tank."	The Department removed Tanks 135 and 136 from the notification requirement and made the appropriate changes to this requirement.
CHS	Permit Analysis II.C.9.c and II.I.2.e	Remove references to 40 CFR 63, Subpart R	The Department agrees.
CHS	Permit Analysis III.A (Truck Loading Rack System - second sentence)	CHS clarified the intended use for tanks 135 and 136.	The Department has made the appropriate change to the analysis to clarify that Tank 135 may be used in the future to support the new truck loading facility, but Tank 136 will not.

CHS	Permit Analysis III.A (first sentence)	CHS suggested that the first sentence be modified to: "...leave the emission limit in the permit until startup of the new loading rack..."	The Department agrees and made this change.
CHS	I.B	For clarity, CHS suggests that the last sentence of the "Mild Hydrocracker (MHC) Project Update" paragraph be updated, as follows:  "In addition, the permit application reclassifies the FCCU Reactor/Regenerator as a "modified" emitting unit..."	The Department made this change.
CHS	I.B	For clarity of the update being made to the Benzene Reduction Unit project, CHS suggests the final three sentences of the project description be modified, as follows: "The proposed permit action is to replace the PSA tailgas burner tips with tips that have larger ports <b>such that all of the PSA tailgas that is generated can be combusted in H-1001. CHS is also proposing to replace the supplemental fuel (i.e., natural gas, refinery fuel gas) burners in H-1001 to achieve improved NOx emission performance.</b> The current heater is physically capable of combusting refinery fuel gas but <b>cannot</b> meet the existing oxides of nitrogen (NOx) permit limits while doing so. Additionally, the modified heater will have a higher maximum design firing rate (191.8 MMBtu-HHV/hr post project versus 177.7 MMBtu-HHV/hr) and a slight increase in the actual firing rate is also expected." Note that the values the MDEQ included in the PD text (139 and 135 MMBtu-HHV/hr) are the maximum expected heat input to H-1001 provided by the PSA tailgas stream post- and pre- project, respectively.  This comment also applies to page 23 of the Montana Air Quality Permit Analysis and pages 1-2 of the Draft Environmental Assessment.	The Department agrees with the changes to this section and has made them accordingly.
CHS	I.B	In the last paragraph on this page, CHS suggests the following clarification relating to the existing SO2 monitor on H-1001: "...exemptions from hydrogen sulfide/sulfur dioxide (H2S/SO2) monitoring requirements for fuel gas streams that are inherently low in sulfur content. The <b>primary fuel to H-1001, PSA tailgas, is inherently low in</b>	The Department made these changes to the permit, permit analysis and EA.

		<p><b>sulfur content.</b> CHS already monitors the H<sub>2</sub>S content of the refinery fuel gas (RFG) to be combusted in H-1001 <b>as supplemental fuel</b>, which would meet the monitoring requirements of 40 CFR 60, Subpart Ja.”</p> <p>This comment also applies to 2nd paragraph on page 24 of the MAQP Analysis and page 2 of the Draft EA.</p>	
CHS	IV.A.3.	In this condition in the HDS/Mild Hydrocracker section of the permit, the FCCU Regenerator and FCC Charger Heater NEW were added to the list of sources subject to NSPS Ja. These sources have already been identified as subject to NSPS Ja as part of condition A.3. in Section X of the permit relating to the FCC Unit. For this reason, the references to these sources should be removed from this condition (IV.A.3.).	<p>This section merely reiterates applicable requirements. In keeping with how this permit has been written historically, the Department retained this section. However, the Department agrees the permit may need to be updated (or restructured) in the future.</p> <p>The Department suggests CHS review the existing permit and consider meeting with the Department in the near future.</p>
CHS	IV.F.4 and 5	These two permit conditions relate to the testing requirements of the H-102 Reformer Heater and are repetitive in terms of compliance with the NSPS Subpart Ja testing requirements. For this reason, CHS suggests that condition IV.F.5. be removed from the permit.	The Department has made this change.
CHS	VIII.A.	As noted in condition VIII.D.3.d.i., the H-1001 Reformer Heater will be subject to NSPS Subpart Ja after the project is complete. As such, a reference to NSPS Subpart Ja should be added to Section VIII.A. of the permit.	The Department agrees and has added this requirement.
CHS	VIII.D.3.d.1.	<p>Note that in the final NSPS Subpart Ja published on September 12, 2012, the NO<sub>x</sub> concentration based standard for natural draft process heaters was changed (see 60.102a.(g)(2)(i)(A)). CHS recommends this condition reference the regulatory citation of the final NO<sub>x</sub> standard or update the existing condition, as follows:</p> <p>“40 ppmv (dry basis, corrected to 0-percent excess air) <b>determined daily on a 30-day rolling average basis</b> <del>on a 24-hour rolling average basis</del> (40 CFR 60, Subpart Ja).”</p>	In 2008, the averaging period for the NO <sub>x</sub> limit as originally promulgated in 40 CFR 60, Subpart Ja was based on a 24-hour rolling average. However, since that time, portions of this standard (which included fuel combustion devices) were stayed for a period of time. On September 12, 2012 the stay was lifted and the final rule was promulgated. Although this emission limit was proposed (by CHS) and determined to be BACT (by the Department), the limit was based on the requirements of Subpart Ja. Therefore, the averaging period was changed accordingly.
CHS	VIII.D.3.a., 3.d., and 3.e.	The new permit conditions for the H-1001 Reformer Heater contain a firing rate limit (MMBtu/hr) and CO and NO <sub>x</sub> emission rate limits expressed as lb/MMBtu. CHS understands that the underlying intent of proposing a firing	In the preliminary determination (PD), the BACT NO <sub>x</sub> limit was determined to be 0.035 lb/MMBtu-HHV based on a 365-day rolling average. CHS requested that this limit be changed to 29.4 tpy based on a 12-calendar month

		<p>rate limit in addition to the proposed lb/MMBtu limits for NOx and CO is to limit mass emissions (lb/hr and TPY). However, implementing a compliance monitoring and assurance program for limits expressed in terms of “MMBtu” for this heater, in particular, is difficult. As discussed in the permit application, the H-1001 Reformer Heater utilizes two fuel sources. The PSA tailgas fuel stream is generated within the 1000 Unit Hydrogen Plant and supplies the majority of the fuel required by the heater during normal operation. The supplemental fuel source is either refinery fuel gas (RFG) or natural gas (NG). The RFG has a relatively consistent BTU content and is monitored through existing systems including an online process GC (i.e., not a CEM) and lab analysis of grab samples such that the composition and subsequently the BTU content of the RFG can be characterized fairly well on a regular basis. In contrast, the PSA tailgas fuel stream has a BTU content that can vary significantly over the course of a day or week. Additionally, it does not have an online GC or a reliable grab sampling system (i.e., low pressure sampling of a stream containing a significant % of hydrogen) such that its Btu content can be characterized in a frequent and accurate manner to be useful in assuring compliance with limits based on short term measurements of the fuel BTU content. CHS estimates that due to the sampling issues only approximately 20% of the samples collected of the 1000 Unit PSA tailgas are valid samples.</p> <p>In consideration of the factors discussed above, CHS is proposing to combine the proposed firing rate limit (MMBtu/hr-HHV) and the lb/MMBtu limits into the more conventional lb/hr and TPY limits, as summarized below:</p> <p>conventional lb/hr and TPY limits, as summarized below:</p> <p><b>NOx, short term:</b> (191.84 MMBtu-HHV/hr) X (0.04 lb/MMBtu-HHV) = <b>7.7 lb/hr, hourly rolling 24-hour average</b></p> <p><b>NOx, long term:</b> (191.84 MMBtu-HHV/hr) X (0.035 lb/MMBtu-HHV) X</p>	<p>total. In keeping with the BACT analysis presented in the application by CHS, the Department retained the lb/MMBtu limit but added the requested TPY limitation too. These are essentially equivalent and CHS would have the option to comply with one <u>or</u> the other. This preserves the BACT analysis presented in the application from CHS, the BACT determination and gives CHS some flexibility with demonstrating compliance.</p> <p>CHS noted that VIII.D.3.d.iii and VIII.D.3.i are essentially equivalent and recommended that the Department delete Section VIII.D.3.d.iii; however, the Department disagrees. On July 2, 2012, CHS submitted information to the Department to request a short term NOx limit of 0.04 lb/MMBtu to account for the variability in the gas composition and other factors that impact the heater’s short term NOx emissions which are not accounted for in the vendor guarantees. This was presented as BACT and did not mention 40 CFR 60, Subpart Ja. Therefore, the Department retained this short term limit in lb/MMBtu (as BACT) but also added the lb/hr limitation requested by CHS.</p> <p>The Department acknowledges that CHS is adding a NOx CEMs and a stack flow monitor in addition to the existing CO CEMs in order to monitor ongoing compliance with the lb/hr and TPY limits. This compliance method is acceptable to the Department.</p> <p>As a side note, the Department added the CO CEMS requirement back into the permit as it was inadvertently deleted.</p>
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		<p>(8760 hr/yr) X (1 T/2000 lb) = <b>29.4 tons/rolling 12-calendar month total</b></p> <p><b>CO, long term:</b> (191.84 MMBtu-HHV/hr) X (0.02 lb/MMBtu-HHV) X (8760 hr/yr) X (1 T/2000 lb) = <b>16.8 tons/rolling 12-calendar month total</b></p> <p><b>CO, startup/shutdown:</b> (191.84 MMBtu-HHV/hr) X (0.04 lb/MMBtu-HHV) = <b>7.7 lb/hr, rolling 24-hour average during periods of startup and shutdown</b></p> <p>Compliance with the proposed lb/hr and TPY limits would be demonstrated through the use of the currently required NOx and CO CEMs and a <u>stack flue gas flowrate meter</u> (being proposed by CHS, with an appropriate moisture correction). Although CHS identified BACT for this heater in terms of lb/MMBtu (and the MDEQ expressed the firing rate limit as BACT), CHS believes it is appropriate to incorporate the lb/hr and TPY limits now being proposed by CHS as BACT limits for the H-1001 Reformer Heater for the following reasons: 1) the proposed limits are derived by simply multiplying the proposed BACT limits together, 2), the proposed limits better accomplish the goal of restricting the short and long term emissions from the H-1001 Reformer Heater through the use of continuous concentration and flow monitors rather than determining an average of a number of grab samples, 3) the proposed limits are expressed in terms that the CHS Operations staff has the ability to monitor in order to <u>ensure</u> continuous and ongoing compliance.</p> <p>Note that if the MDEQ does not agree with the approach proposed above for monitoring and assuring compliance with the NOx and CO emission standards, based on the same sampling issues described above CHS has the following comments with regards to the limits proposed in the current draft permit:</p> <p>1. CHS proposes the firing rate limit be expressed as: “191.84 MMBtu/hr-HHV based on a <del>rolling hourly</del> <b>monthly</b> average.” CHS believes it is critical when calculating an actual firing rate</p>	
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		<p>for compliance demonstration in terms of MMBtu/hr that the inputs into the calculation all be collected on the same time basis. For example, an <u>hourly</u> average fuel flow rate (scf/hr) should not be used with a <u>monthly</u> average fuel Btu content measurement to calculate a MMBtu/hr firing rate. Therefore, due to the difficulty in determining the Btu content of the PSA tailgas, CHS proposes that the monthly average Btu content of all valid PSA tailgas samples be used with the monthly average firing rate of the PSA tailgas stream (scf/hr). For the RFG/natural gas, a daily average Btu content and the daily average firing rate (scf/hr) will be used.</p> <p>2. Compliance with the lb/MMBtu limits for NO<sub>x</sub> and CO shall be determined using the pollutant concentration measured by the CEM and weighted F-factor values (updated on a regular basis using data from all valid fuel gas samples representative of the fuel gases burned in H-1001). To be consistent with the firing rate calculation above, the F-factor for PSA tailgas would be updated monthly using the results of all valid samples. The F-factor for the RFG/natural gas would be updated daily.</p> <p>3. Note that conditions VIII.D.3.d.i. and 3.d.iii. are essentially equivalent. NSPS Subpart Ja requires that an affected unit comply with one or the other limit. If the MDEQ chooses to maintain limits expressed in terms of lb/MMBtu (rather than lb/hr or TPY), CHS proposes that condition VIII.D.3.d.iii. be deleted.</p>	
CHS	VIII.D.3.b	<p>CHS requests the following clarification be made to this condition:</p> <p>“All available <b>1000</b> Unit PSA purge gas (sulfur free) shall be fired in the H-1001 Reformer Heater, <b>except during periods of startup, shutdown, operational transition, or process upset.</b>”</p> <p>As discussed in the permit application, PSA tailgas provides the majority of the fuel to H-1001 during normal operations. However, because PSA tailgas is generated as part of the hydrogen production process, it is not</p>	The Department has made the requested change.

		available during the initial stages of startup and must be introduced at a slow rate once it becomes available to maintain operational stability. During heater shutdown, the PSA tailgas stream is removed as a fuel source so the heater can go through a slow and controlled shutdown firing only the supplemental fuel. Additionally, during a process upset or period of operational transition (i.e., significant rate change) a portion of the PSA tailgas fuel may be replaced temporarily with supplemental fuel in order to return to a normal and stable operation more quickly.	
CHS	VIII.D.3.c	This condition includes the NSPS Subpart Ja limit on H <sub>2</sub> S in the fuel gas to be combusted in H-1001. Note that in Section III of the permit, condition III.C.7. includes the same requirement for all fuel gas combustion devices where construction, reconstruction, or modification commenced after May 14, 2007. CHS believes that the condition in Section III adequately covers H-1001 such that condition VIII.D.3.c. should be deleted to avoid having two permit limits for the same thing. As noted above, CHS does believe it is appropriate to list NSPS Subpart Ja applicability to H-1001 in Section VIII.A.	The Department agrees that this requirement is also covered in Section III.C.7 as a general applicable requirement. However, CHS presented this limit as BACT for SO <sub>2</sub> and the Department retained this in the permit.
CHS	VIII.E.1	The requirement for an O <sub>2</sub> monitor is listed twice in this condition. CHS suggests that VIII.E.1.a. be deleted. Additionally, if the MDEQ agrees with the CHS proposal for lb/hr and TPY NO <sub>x</sub> and CO limits, a stack flow monitor, with an appropriate correction for moisture, is required. This requirement should be added to this condition in the permit.	The Department agrees and has made the appropriate changes.
CHS	VIII.E.2	This condition identifies the regulatory programs that apply to the CEMS on H-1001 and should be updated as follows:  “CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, <del>Subpart Db 60.40b through 60.49b, Subpart J, 60.100-108,</del> <b>Subpart Ja, 100a-108a</b> and Appendix B, Performance Specifications 2, 3, 4 or 4A, and Appendix F.”  Additionally, as written, the condition references the use of a volumetric flow	The Department agrees and has made the necessary changes.

		rate monitor. If the MDEQ agrees with the CHS proposal to install a stack flow monitor for demonstrating compliance with lb/hr and TPY limits, then no update to the final sentence of this condition is required. If the MDEQ does not agree with the CHS proposal, then reference to a flow rate monitor should be removed.	
CHS	VIII.E.	<p>In a previous comment, CHS proposed to replace the firing rate limit (MMBtu/hr) and lb/MMBtu limits for CO and NOx with lb/hr and TPY limits. If this change is incorporated into the permit, the following monitoring requirement should be added to this section. Note that CHS has used as the basis for the proposed condition, condition XIV.F.3. in the Boiler 12 section of the permit:</p> <p>“Compliance with the lb/hr and TPY limits in VIII.D.3. shall be determined using the NOx and CO CEMS and volumetric stack flow rate monitor required in Section VIII.E.”</p> <p>If the CHS proposal to replace the lb/MMBtu limits for NOx and CO with lb/hr and TPY limits is not incorporated into the permit, a monitoring requirement relating to the use of the F-factor for monitoring compliance with the lb/MMBtu limits should be incorporated into section VIII.E. Condition XIV.D.4. in the Boiler 12 section of the permit is used as a reference in the following language:</p> <p>“Compliance with the lb/MMBtu limits will be demonstrated using <del>statistically significant</del> <b>weighted</b> F-factor values. <b>For PSA tailgas, the F-factors will be updated monthly on a regular basis</b> using data from all valid <del>fuel gas</del> samples <b>collected during the previous month. For RFG/natural gas, the F-factor will be updated daily.</b> <del>representative of the fuels burned in H-4001.</del> The method of compliance demonstration involving F-factor statistical significance is subject to change upon agreement with the Department and CHS.”</p> <p>Additionally, it should be noted that compliance with the proposed firing rate limit (MMBtu/hr) will be determined similarly using the previous</p>	The Department added the compliance demonstration for the NOx and CO CEMS as requested.

		day's daily average Btu/scf for RFG/NG and the previous month's average Btu/scf for PSA tailgas.	
CHS	X.D.1.h	<p>Because there may be times that the use of CO combustion promoter is not necessary to adequately control CO emissions from the FCCU Regenerator, CHS proposes the following modification to this new permit condition:</p> <p>“CO and VOC emissions from the FCCU Regenerator stack shall be controlled through the use of CO combustion promoters, <b>as needed</b>, and good combustion practices. Compliance with the FCCU Regenerator Stack CO emission limits shall be used as a surrogate for VOCs.”</p>	The Department agrees with this change.
CHS	X.D.2	<p>CHS recognizes that the paragraph just below the X.D.2. section heading has not been modified as part of this permit amendment. However, CHS requests that the following clarification be made to avoid confusion about what is expected:</p> <p>“FCC-Heater-1 shall be shutdown and <b>permanently removed from service</b> as an emissions source within 180 days of the initial startup of FCC-Heater-NEW.”</p> <p>As it is currently written, it may be interpreted to mean that the heater has to be physically removed. CHS believes that the key is that the heater be <u>removed from service</u> and no longer operate as an emission source.</p>	<p>The Department made several clarifications to the FCC-Heater-1 and FCC-Heater new. In addition, the Department added notification requirements for the FCC-Heater-1 and the FCC-Heater-NEW.</p> <p>The Department has made this clarification and added a notification requirement that will be used to document that the FCC-Heater-1 was permanently removed from service.</p>
CHS	X.D.2a.b.1	<p>Note that in the final NSPS Subpart Ja published on September 12, 2012, the NOx concentration based standard for natural draft process heaters was changed (see 60.102a.(g)(2)(i)(A)). CHS recommends this condition reference the regulatory citation of the final NOx standard or update the existing condition, as follows:</p> <p>“40 ppmv (dry basis, corrected to 0-percent excess air) <b>determined daily on a 30-day rolling average basis</b> <del>on a 24-hour rolling average basis</del> (40 CFR 60, Subpart Ja).”</p>	The Department agrees with this and made changes accordingly.

		<p><b>Note that CHS intends to demonstrate compliance with the NSPS Subpart Ja NOx concentration based standard through the use of a NOx/O<sub>2</sub> CEM rather than a biennial performance test and O<sub>2</sub> operating limit or O<sub>2</sub> operating curve.</b></p>	
CHS	X.D.2.a.a and b	<p>In review of the draft permit conditions for the new FCC Charge Heater, CHS recognized that the limits are stated in such a way that result in duplicate emission limits. For example, combining a firing rate limit (MMBtu/hr) with a NOx emission rate limit (lb/MMBtu) duplicates a lb/hr or ton/rolling 12-calendar month limit.</p> <p>As such, in an approach similar to that suggested for the H-1001 Reformer Heater, CHS proposes that the limits for the new FCC Charge Heater be expressed only in terms of lb/hr and tons/rolling 12-calendar month totals and not in terms of MMBtu (i.e., MMBtu/hr and lb/MMBtu). As discussed above, CHS intends to install a NOx/O<sub>2</sub> CEM to comply with the NSPS Subpart Ja concentration standard. CHS proposes to use the CEM along with a <u>stack flue gas flow rate monitor (with appropriate moisture correction)</u> to comply with the mass emission limits.</p> <p>CHS believes this approach is the most effective in accomplishing the goal of restricting the short and long term NOx emissions from the new FCC Charge Heater through the use of continuous concentration and stack flow monitors. Additionally, the limits are expressed in terms that the CHS Operations staff has the ability to monitor in order to <u>ensure</u> compliance.</p> <p>Following is a summary of what CHS is proposing for conditions X.D.2a.a. and b. of the draft permit:</p> <p>“2a.a. The FCC-Heater-NEW shall be equipped with <del>an</del> ULNB. <del>and the heating capacity of the heater shall not exceed 66 MMBtu/hr HHV based on a rolling hourly average.</del> (ARM 17.8.752).”</p> <p>“<del>2a.b.ii. 0.035 lb/MMBtu HHV based on a 365 day rolling average (ARM</del></p>	<p>In keeping with the BACT analysis presented in the application and the Department’s BACT determination, Department retained the lb/MMBtu limit but added the requested lb/hr and TPY limits as requested. The Department agrees these are essentially equivalent and CHS would have the option to comply with <u>one or the other</u>. This preserves the BACT analysis but also gives CHS some flexibility with demonstrating compliance.</p> <p>CHS requested changes to the averaging periods for the NOx emission limits and the Department has made these changes. However, the Department retained the firing rate limit but increased the averaging period from an hourly average to a 30-day rolling average..</p> <p>The Department acknowledges that CHS is adding a NOx/O<sub>2</sub> CEMs and a stack flow monitor in addition to the existing CO CEMS in order to monitor ongoing compliance with the lb/hr and TPY limits. This compliance method is acceptable to the Department.</p>

		<p>17.8.752)”</p> <p>“2a.b.iii. <del>0.04 lb/MMBtu HHV based on a 24-hour rolling average.</del>”</p> <p>“2a.b.iv. 2.6 lb/hr, <b>hourly rolling 24-hour average.</b>” Note that this limit is calculated by simply multiplying 66 MMBtu/hr-HHV (firing rate) X 0.04 lb/MMBtu-HHV (short term lb/MMBtu basis).</p> <p>“2a.b.v. 10.1 tons/rolling 12-calendar month total (ARM 17.8.749).” Note that CHS is not proposing any change to this condition. This limit is calculated by simply multiplying 66 MMBtu/hr-HHV X 8760 hr/hr X 0.035 lb/MMbtu-HHV (long term lb/MMBtu basis) X 1 T/2000 lb.</p>	
CHS	X.D.2.a.c	<p>For CO emissions at the FCC Charge Heater, CHS questions the necessity of having both concentration (ppm) and mass emission rate (lb/hr and TPY) limits. CHS proposes that the concentration limit be maintained with compliance demonstrated during a biennial performance test (i.e., CO reference method testing of three one hour samples representative of normal operation). CHS proposes the mass emission rate limits be removed because they are both based on the CO concentration limit included in the permit. Additionally, for this source and the MHC project, CO emissions are not of a concern in terms of air quality impacts or in the determination of whether the project constitutes a major modification.</p>	<p>The Department has removed the mass emission rate limits for CO and left the concentration based limit as BACT.</p>
CHS	X.D.2.a.d	<p>This condition includes a limit on CO emissions during periods of startup and shutdown. While CHS anticipates that CO emissions will be higher during periods of startup and shutdown as discussed in the heater’s BACT analysis, without a CO CEM, there is no means for demonstrating compliance with this permit limit. Routine performance testing is not done during periods of startup and shutdown. For these reasons, CHS suggests that this permit condition be removed from the permit.</p>	<p>The Department removed this limit. As such, the existing CO limit would apply at all times, including startup and shutdown.</p>
CHS	X.D.2.a.e	<p>This condition includes the NSPS Subpart Ja limit on H<sub>2</sub>S in the fuel gas</p>	<p>The Department agrees that this requirement is also covered in Section</p>

		to be combusted in the new FCC Charge Heater (FCC-Heater-NEW). Note that in Section III of the permit, condition III.C.7. includes the same requirement for all fuel gas combustion devices where construction, reconstruction, or modification commenced after May 14, 2007. CHS believes that the condition III.C.7. adequately covers the new FCC Charge Heater such that condition X.D.2a.e. should be deleted to avoid having two permit limits for the same thing.	III.C.7 as a general applicable requirement. However, CHS presented this limit as BACT for SO <sub>2</sub> and the Department retained this in the permit.
CHS	X.E.	As discussed above, CHS has proposed to install a NOx/O <sub>2</sub> CEM on the new FCC Charge Heater to demonstrate compliance with the NOx concentration standard in NSPS Subpart Ja as well as the proposed mass emissions rates. Additionally, CHS is proposing to install a stack flue gas flow rate monitor (with appropriate moisture correction) on the new FCC Charge Heater to be used along with the NOx CEM in demonstrating compliance with the mass emission limits. As such, these monitoring systems should be added to this section of the permit.	The Department added CEMS and monitoring requirements to this section.
CHS	X.F.3	This condition includes the testing requirements for the new FCC Charge Heater. As discussed previously, CHS has elected to install a NOx/O <sub>2</sub> CEM and volumetric flow rate monitor to demonstrate compliance with the NSPS Subpart Ja NOx concentration standard. As such, a specific testing requirement is not necessary in this section as it is covered for CEMs in Section X.E.	The Department has made the appropriate change to this section
CHS	X.G.3	This section includes the compliance determination requirements for the new FCC Charge Heater. As discussed above, CHS is electing to install a NOx/O <sub>2</sub> CEM and stack flow rate monitor to demonstrate compliance with the NSPS Subpart Ja NOx standard and the lb/hr and TPY limits for NOx. As such, the initial compliance testing outlined in the draft permit will not be required. CHS suggests that biennial testing (i.e., CO reference method testing of three one hour samples representative of normal operations) is completed to demonstrate compliance with the CO concentration limit.	The Department has made the appropriate change to this section.

CHS	X.H.	For clarity, CHS suggests that the existing reporting requirements for CO, SO <sub>2</sub> and NO <sub>x</sub> be further defined as relating to the FCCU Regenerator Stack.	The Department modified this section to also include the FCC-Heater –NEW, but highlighted that SO <sub>2</sub> is only required for the FCCU Regenerator Stack.
CHS	X.I.2	For clarity, CHS suggests that the condition be updated as follows:  “...written notification of the actual start-up date of the <b>FCC Unit with the new Catalyst Riser</b> within 15 days...”	The Department agrees and has made this change.
CHS	Permit Analysis I.C.	For clarity, CHS suggests that the following modification be made to the text in the “Mild Hydrocracker (MHC) Project Update” section:  “In addition, the permit application reclassifies the Fluid Catalytic Cracking Unit (FCCU) <b>Reactor/Regenerator</b> as a “modified” emitting unit....”	The Department has made this clarification.
CHS	Permit Analysis I.C.	With the purpose of making the project description concise, CHS suggests the bullets in the “Mild Hydrocracker (MHC) Project Update” section be deleted and summarized in the last sentence of the first paragraph, as follows:  “The Riser replacement incorporates a new design to improve temperature control in the process, minimize CO emissions and improve product yields.”	The Department has made this change.
CHS	Permit Analysis III.A	CHS would like to provide clarification to one of the MHC project elements listed in the last sentence of the last paragraph on page 41. There will be a new FCC Charge Heater installed but its design firing rate is actually less than the design firing rate of the existing FCC Charge Heater. The current limit on the firing rate of the existing heater (condition X.D.2.a.) was established as part of a previously permitted project to limit emissions from this source.	The Department has modified this language.
CHS	Permit Analysis III.A	For consistency, in the first sentence on page 42, CHS suggests that “FCCU Regenerator” be changed to “FCCU <b>Reactor/Regenerator</b> ”.	The Department had made this clarification.
CHS	Permit Analysis III.A.	CHS proposes to make a clarification in the first sentence under the “FCC	The Department has made this change.

		Charge Heater” paragraph. There are many factors that impact the actual physical firing capacity of a process heater including its actual efficiency, firebox, burner, stack and fuel characteristics and ambient conditions. For this reason, rather than stating the heater will have a “rated capacity” of 66 MMBtu-HHV/hr, CHS proposes that it state that the heater will have a “maximum process heat input” of 66 MMBtu-HHV/hr.	
CHS	Permit Analysis III.A.	As discussed above, there are many factors that impact the actual physical firing capacity of a process heater. For clarification, CHS suggests that in the third paragraph on this page, the term “heating capacity” be changed to “heat input”.	The Department has made this change.
CHS	Permit Analysis III.A	In review of the permit analysis, CHS noticed that the MDEQ did not restate the PM BACT analysis for the final design of the FCC Charge Heater as was done for the other pollutants. For the permit record, CHS did not modify the original PM BACT analysis for the heater as included in the application for MAQP 1821-23 other than to update a cost effective calculation based on the slight increase in the final firing rate.	The Department has added a summary of the PM BACT analysis provided by CHS. This was inadvertently left out. The limit associated with this unit remains unchanged as follows: “CHS shall implement proper design and good combustion techniques to minimize CO, VOC, and PM/PM <sub>10</sub> /PM <sub>2.5</sub> emissions (ARM 17.8.752).”
CHS	Permit analysis, IV.	CHS suggests the following clarification to the paragraph directly under the “IV. Emission Inventory” heading:  “Many of these units were previously approved in other permit actions, this permit action only addresses the <b>final design and location of the new FCC Charge Heater and a new Riser and Riser design, and the FCCU Regenerator that changes the FCCU Reactor/Regenerator from being a project “affected” emitting unit to a “modified” emitting unit.</b> ”	The Department made some the suggested changes with the exception of the FCC Charge Heater.  Since the FCC Charge Heater (approved in MAQP #1821-23) was never constructed, the change in design and location of the FCC Charge heater was viewed as a new unit by the Department.
CHS	Draft EA, 2.	For clarity, CHS suggests that the following modification be made to the text in the “Mild Hydrocracker (MHC) Project Update” section:  “In addition, the permit application reclassifies the Fluid Catalytic Cracking Unit (FCCU) <b>Reactor/Regenerator</b> as a “modified”	The Department has made this change.

		emitting unit....”	
CHS	Draft EA, 3.	CHS suggests the “Objectives of Project” relating to the H-1001 Reformer heater retrofit (item 3) be modified as follows to add clarity:  “3) to modify the existing H-1001 Reformer heater by replacing the PSA tailgas burner tips with tips that have larger ports <b>and by replacing the supplement fuel burners to achieve improved NOx emission performance.</b> ”	The Department has made this change.
CHS	Draft EA, 7.A.	Note that the facility-wide emission caps established in MAQP #1821-05 in 2000 were updated in 2004 as part of MAQP #1821-11 to reflect improved CO data from the FCCU regenerator.  This comment also applies to items 7.J. and 8.L. of the draft Environmental Assessment.	The Department has adjusted this language in all sections.
Department Comment	Permit Analysis III.A	For clarification of the FCC Charge Heater BACT analysis, the Department changed the header to reflect that this analysis is for the FCC-Heater-NEW. It seems as though it was referred to differently throughout the analysis.	
Department Comment	Permit Section X.C	Over the past several permit actions, the Department did not re-evaluate the existing opacity limitations in this section. In making changes through the comment period, the Department realized that Section X.C listed incorrect opacity limitation and did not discuss opacity for the FCC-Heater-NEW. Therefore, the Department added the correct opacity limit for the FCCU Regenerator Stack pursuant to the CHS consent decree, and added an opacity for the FCC-Heater-NEW.	Section X.C changed as follows:  1. CHS shall not cause or authorize emissions to be discharged from the FCCU Regenerator Stack into the outdoor atmosphere that exhibit an opacity of 30% or greater averaged over 6 consecutive minutes (ARM 17.8.304, CHS Consent Decree Paragraph 55).  2. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from the FCC-Heater-1 installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304).  3. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that

			exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 and 40 CFR 60, Subpart Ja).
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F. Additional Information

Additional information, such as applicable rules and regulations, BACT/Reasonably Available Control Technology (RACT) determinations, air quality impacts, and environmental assessments, is included in the analysis associated with each change to the permit.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available upon request from the Department. Upon request, the Department will provide references for locations of complete copies of all applicable rules and regulations, or copies, where appropriate.

A. ARM 17.8, Subchapter 1 – General Provisions, including, but not limited to:

1. ARM 17.8.101 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.
2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment, including instruments and sensing devices, and shall conduct tests, emission or ambient, for such periods of time as may be necessary, using methods approved by the Department.
3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Montana Clean Air Act, 75-2-101, *et seq.*, MCA.

CHS shall comply with all requirements contained in the Montana Source Test Protocol and Procedures Manual including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours.
5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

B. ARM 17.8, Subchapter 2 – Ambient Air Quality, including, but not limited to the following:

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
8. ARM 17.8.221 Ambient Air Quality Standard for Visibility
9. ARM 17.8.222 Ambient Air Quality Standard for Lead
10. ARM 17.8.223 Ambient Air Quality Standard for PM<sub>10</sub>

CHS must comply with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 – Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.
2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, CHS shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.
3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.
4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.
5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions.
6. ARM 17.8.324 Hydrocarbon Emissions – Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.
7. ARM 17.8.340 Standard of Performance for New Stationary Sources. The owner or operator of any stationary source or modification, as defined and applied in 40 CFR Part 60, shall comply with the standards and provisions of 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS). The applicable NSPS Subparts include, but are not limited to:

- a. Subpart A - General Provisions apply to all equipment or facilities subject to an NSPS Subpart as listed below.
- b. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units applies to Boilers #10, #11, and #12.
- c. Subpart J - Standards of Performance for Petroleum Refineries shall apply to the SRU Incinerator Stack (E-407 & INC-401), Fractionator Feed Heater Stack (H-202), Reactor Charge Heater Stack (H-201), the FCCU Regenerator, and all fuel gas combustion devices, as applicable, with the exception of the Naphtha Unifier Splitter Heater, the Hydrogen Reformer Heaters (H-101 and H-102), the Alkylation Hot Oil Belt Heater, the Loading Rack Vapor Combustion Unit, and the Refinery Flare (CHS Consent Decree paragraphs 55, 57, and Appendix F).
- d. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 shall apply to (but not limited to): Boiler #12, H-1001 Reformer heater, FCC Regenerator (for CO only), FCC-Heater-NEW, the Platformer Splitter Reboiler (P-HTR-30, and the Refinery Flare (once new connections are made). Note: Once the final revised Subpart Ja provisions are promulgated, those final provisions affecting flares will apply to the Refinery Flare.
- e. 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 shall apply to Tanks 135 and 136 and any other applicable tanks.
- f. Subpart XX - Standards of Performance for Bulk Gasoline Terminals the construction or modification of which is commenced after December 17, 1980,
- g. Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture shall apply to Tank 133 while in asphalt service.
- h. Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the HDS Complex, including, but not be limited to, the SRU Incinerator Stack (E-407 & INC-401), Superior Clean Burn II 12 SGIB (C201-B), Fractionator Feed Heater Stack (H-202), Reactor Charge Heater Stack (H-201), the Reformer Heater Stacks (H-101 and H-102), refinery fuel gas supply lines to the Boilers #10, and #12, the fugitive ULSD Unit and Hydrogen Plant fugitive piping equipment, the Zone A TGTU fugitive piping equipment in VOC service, the Delayed Coker Unit fugitive piping equipment in VOC service and the Naptha Hydrotreating Unit and any other applicable equipment constructed or modified after January 4, 1983.
- i. Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, shall apply to all of the fugitive VOC emitting components added in the Benzene Reduction Unit project and any other applicable equipment constructed, reconstructed, or modified after November 7, 2006.



2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

F. ARM 17.8, Subchapter 7 – Permit, Construction, and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.
2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. CHS has a PTE greater than 25 tons per year of SO<sub>2</sub>, NO<sub>x</sub>, CO, VOC, and PM emissions; therefore, an air quality permit is required.
3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.
4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under Montana Air Quality Permit Program.
5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, modification, or use of a source. A permit application was not required for the current permit action because the permit change is considered an administrative permit change. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. CHS submitted an affidavit of publication of public notice for the May 23, 2012, issue of the *Billings Gazette*, a newspaper of general circulation in the City of Billings in Yellowstone County, as proof of compliance with the public notice requirements.
6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.
8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.
9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving CHS of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq.*
10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.
11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or modified source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.
12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).
13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.
14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to the Department.
15. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to the Department for incineration facilities subject to 75-2-215, MCA.

G. ARM 17.8, Subchapter 8 – Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.
2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications -- Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

CHS's existing petroleum refinery in Laurel is defined as a "major stationary source" because it is a listed source with a PTE more than 100 tons per year of several pollutants (PM, SO<sub>2</sub>, NO<sub>x</sub>, CO, and VOCs). The projects considered in this modification will not cause a project-related emissions increase greater than significance levels and, therefore, does not require a New Source Review (NSR) analysis.

H. ARM 17.8, Subchapter 9 – Permit Requirements for Major Stationary Sources of Modifications Located within Nonattainment Areas including, but not limited to:

ARM 17.8.904 When Air Quality Preconstruction Permit Required. This rule requires that major stationary sources or major modifications located within a nonattainment area must obtain a preconstruction permit in accordance with the requirements of this Subchapter, as well as the requirements of Subchapter 7.

The current permit action is not considered a major modification because no increase in emissions will occur as a result. Therefore, the requirements of this subpart are not applicable.

I. ARM 17.8, Subchapter 12 – Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any stationary source having:
  - a. PTE > 100 tons/year of any pollutant;
  - b. PTE > 10 tons/year of any one HAP, PTE > 25 tons/year of a combination of all HAPs, or a lesser quantity as the Department may establish by rule; or
  - c. PTE > 70 tons/year of PM<sub>10</sub> in a serious PM<sub>10</sub> nonattainment area.
2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204 (1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #1821-27 for CHS, the following conclusions were made:
  - a. The facility's PTE is greater than 100 tons/year for several pollutants.
  - b. The facility's PTE is greater than 10 tons/year for any one HAP and greater than 25 tons/year of all HAPs.

- c. This source is not located in a serious PM<sub>10</sub> nonattainment area.
- d. This facility is subject to NSPS requirements (40 CFR 60, Subparts A, Db, J, Ja, Kb, XX, GGG, GGGa, and QQQ).
- e. This facility is subject to current NESHAP standards (40 CFR 61, Subpart FF and 40 CFR 63, Subparts CC, UUU, and ZZZZ).
- f. This source is not a Title IV affected source, nor a solid waste combustion unit.
- g. This source is not an EPA designated Title V source.

Based on these facts, the Department determined that CHS is a major source of emissions as defined under Title V and currently operates under Operating Permit #OP1821-10, which was issued final and effective on July 21, 2012. However, CHS submitted a concurrent application to modify the existing Title V Operating Permit.

J. MCA 75-2-103, Definitions, provides, in part, as follows:

- 1. “Incinerator” means any single or multiple-chambered combustion device that burns combustible material, alone or with a supplemental fuel or catalytic combustion assistance, primarily for the purpose of removal, destruction, disposal, or volume reduction of all or any portion of the input material.
- 2. “Solid waste” means all putrescible and nonputrescible solid, semisolid, liquid, or gaseous wastes, including, but not limited to...air pollution control facilities...

K. MCA 75-2-215, Solid or Hazardous Waste Incineration -- Additional Permit Requirements, including, but not limited to, the following requirements:

The Department may not issue a permit to a facility until the Department has reached a determination that the projected emissions and ambient concentrations will constitute a negligible risk to the public health, safety, and welfare and to the environment.

Health Risk Assessment (MAQP #1821-04)

For MAQP #1821-04, CHS submitted a health risk assessment identifying the risk from the burning of HAPs in the flare as part of their permit application. The risk assessment contained the HAPs from the 1990 Federal Clean Air Act Amendments with an established risk value. The ambient concentrations were determined using ISCT3 and the risk assessment model used EPA’s unit risk estimates and reference concentrations. The Department included limits in the permit that ensure the amount of material used in the models was not exceeded. The risk assessment results were summarized in the following table.

Flare Risk Assessment - CHS Refinery, MAQP #1821-04

Chemical Compound	Hourly	Cancer	Non-Cancer	
	Conc	ELCR	Hazard Quotient	
	$\mu\text{g}/\text{m}^3$	Chronic	Chronic	Acute
Benzene*	4.67E-02	8.3E-06	3.9E-07	ND
Toluene	3.82E-02	ND	ND	ND
Ethyl Benzene	2.85E-03	ND	ND	ND
Xylenes	1.25E-02	ND	ND	ND
Hexane	8.55E-02	ND	ND	ND
Cumene	1.14E-04	ND	ND	ND
Napthalene	1.60E-05	ND	ND	ND
Biphenyl	7.98E-08	ND	ND	ND
Total Risks =	0.186	8.3E-06	3.9E-07	ND

\*The reference concentration for Benzene is  $71 \mu\text{g}/\text{m}^3$  (EPA IRIS database).

The modeling demonstrated that the ambient concentrations of HAPs, with the exception of Benzene, are less than the concentrations contained in Table I and Table II of ARM 17.8.770; therefore, these HAPs were excluded from further review.

A risk assessment for Benzene was calculated because the predicted ambient concentration was greater than the concentration contained in Table I of ARM 17.8.770. This assessment demonstrated that the excess lifetime cancer risk was  $3.9 \times 10^{-7}$ . Therefore, the Department determined that the health risk assessment model demonstrated negligible risk to public health in this case.

Health Risk Assessment (MAQP #1821-13)

For MAQP #1821-13, CHS submitted a health risk assessment identifying the risk from the burning of HAPs in the rail loading rack VCU as part of their permit application. The risk assessment contained the HAPs from the 1990 Federal Clean Air Act Amendments with an established risk value. The ambient concentrations were determined using ISC3 and the risk assessment model used EPA's unit risk estimates and reference concentrations. The Department included limits in the permit that ensure the amount of material used in the models was not exceeded. The risk assessment results were summarized in the following table.

Rail Loading Rack VCU Risk Assessment - CHS Refinery, MAQP #1821-13

Chemical Compound	Modeled	Table 1*	Table 2*
	Conc.	Conc.1	Conc.
	$\mu\text{g}/\text{m}^3$	$\mu\text{g}/\text{m}^3$	$\mu\text{g}/\text{m}^3$
Benzene	1.81E-02	1.20E-02	7.10E-01
Ethyl Benzene	8.29E-04	--	1.00E+01
Napthalene	4.08E-05	--	1.40E-01
Toluene	1.22E-02	--	4.00E+00
Xylenes	4.35E-03	--	3.00E+00
Hexane	2.68E-02	--	2.00E+00
Total concentrations =	0.0623		

\*Refers to ARM 17.8.770

The modeling demonstrated that the ambient concentrations of HAPs, with the exception of Benzene, are less than the concentrations contained in Table 1 and Table 2 of ARM 17.8.770; therefore, these HAPs were excluded from further review.

A risk assessment for Benzene was calculated because the predicted ambient concentration was greater than the concentration contained in Table I of ARM 17.8.770. The modeled benzene concentration was compared to EPA Region III's, "Risk-Based Concentration (RBC) Table," dated October, 2005. RBC screening levels represent concentrations which are determined to present a lifetime cancer risk of no greater than  $1 \times 10^{-6}$ . The RBC concentration for benzene is listed as  $2.3 \times 10^{-1}$ , which is higher than the modeled concentration for benzene. Therefore, the Department determined that the health risk assessment model demonstrated negligible risk to public health in this case.

Although CHS proposes to expand the railcar light product loading rack under MAQP #1821-17, no modifications to the VCU are proposed. In addition, the basis for the Human Health Risk assessment submitted as part of MAQP #1821-13 has not changed. As such, an additional assessment is not necessary for the proposed expansion of the railcar light product loading rack.

Also for MAQP #1821-13, CHS submitted a health risk assessment identifying the risk from the burning of HAPs in the coker unit TGI as part of their permit application. The risk assessment contained the HAPs from the 1990 Federal Clean Air Act Amendments with an established risk value. The ambient concentrations were determined using SCREEN3 and the risk assessment model used EPA's unit risk estimates and reference concentrations. The Department included limits in the permit that ensure the amount of material used in the models was not exceeded. The risk assessment results were summarized in the following table.

Coker Unit TGI Risk Assessment - CHS Refinery, MAQP #1821-13

Chemical Compound	Modeled Conc. $\mu\text{g}/\text{m}^3$	Table 1* Conc.1 $\mu\text{g}/\text{m}^3$	Table 2* Conc. $\mu\text{g}/\text{m}^3$
Carbon Disulfide	3.18E-02	--	7.00E-00
Total concentrations =	3.18E-02		

\*Refers to ARM 17.8.770

The modeling demonstrated that the ambient concentrations of the carbon disulfide (the only HAP expected to be emitted), are less than the concentrations contained in Table 1 and Table 2 of ARM 17.8.770; therefore, the carbon disulfide were excluded from further review. Updated information provided to the Department on October 24, 2006, revised the modeled concentration of carbon disulfide to 3.05E-02, which did not effect this determination. Therefore, the Department determined that the health risk assessment model demonstrated negligible risk to public health in this case.

Health Risk Assessment (MAQP #1821-27)

For MAQP #1821-27, a full health risk assessment was completed as a part of the application identifying the risk from the burning of HAPs in the truck loading rack VCU. The risk assessment evaluated the HAPs listed in the 1990 Federal Clean Air Act Amendments with an established risk value. The EPA model AERSCREEN was utilized to estimate a worst case-hourly average concentration of VOCs. To estimate peak concentrations of individual toxic compounds, the maximum VOC concentration was multiplied by speciation factors for gasoline vapors. The Department reviewed the health risk assessment submitted by CHS and verified the results.

ARM 17.8.770(1)(c) exempts individual pollutants from the requirement to perform an HRA provided “exposure from inhalation is the only appropriate pathway to consider” and the ambient concentration of the pollutant is less than the screening levels specified in Table 1 or Table 2 of the rule. Using these tables is considered appropriate because the HAPs emitted from the VCU are not expected to deposit, so inhalation would be the predominant exposure pathway.

The screening threshold tables contain screening-level risk thresholds for chronic cancer risk and chronic and acute non-cancer hazard, though all three values are not provided for all of the HAPs considered in this analysis. Where a screening value was not available, the risk of that type of exposure effect was considered negligible. The results presented in table below show that benzene is the only pollutant for which risk assessments should be performed. All other modeled concentrations are below the screening values.

#### Truck Loading Rack VCU - Screening Level Concentrations

Annual Average, 0.1 x One Hour Maximum VOCs [ $\mu\text{g}/\text{m}^3$ ] <sup>(a)</sup> = 7.055				
Chemical	Annual Average [ $\mu\text{g}/\text{m}^3$ ]	Cancer Chronic <sup>(b)</sup> [ $\mu\text{g}/\text{m}^3$ ]	Non-Cancer Chronic <sup>(c)</sup> [ $\mu\text{g}/\text{m}^3$ ]	Non-Cancer Acute <sup>(c)</sup> [ $\mu\text{g}/\text{m}^3$ ]
Benzene	6.35E-02	1.20E-02	0.71	N/A
Ethylbenzene	7.10E-03	N/A	10.0	N/A
n-Hexane	1.13E-01	N/A	2.0	N/A
Toluene	9.17E-02	N/A	4.0	N/A
m-Xylene	3.53E-02	N/A	3.0	44.0

(a) Annual Maximum concentration calculated by apply a scaling factor of 0.1, as recommended by MDEQ and EPA’s Screening Procedures for Estimating the Air Quality Impact of Stationary Sources (October 1992, EPA-454/R-92-019)

(b) ARM 17.8.770, Table 1.

(c) ARM 17.8.770, Table 2.

Because the peak annual average modeled concentrations of benzene exceeded the ARM 17.8.770 screening-level concentration thresholds, a more refined risk assessment was performed for inhalation exposure to this HAP. General methodology described in EPA’s Human Health Risk Assessment Protocol (HHRAP) was followed.<sup>4</sup>

The peak annual average modeled concentration of benzene was multiplied by a Unit Risk Factor (URF) published by EPA for this type of analysis.<sup>5</sup> The result of this calculation conservatively estimates the probability of developing cancer from exposure to a pollutant or a mixture of pollutants over a 70-year lifetime, usually expressed as the number of additional cancer cases in a given number of people. For example, a cancer risk value of 1.0E-06 is interpreted as a one-in-a-million lifetime probability of the exposure resulting in cancer.

The annual average benzene concentration was divided by its respective Reference Concentrations (RfC) to determine individual non-cancer hazard quotients. RfCs have been developed to compare effects of a theoretical exposure to a standard exposure level with known effects. They represent estimates of daily concentrations that, when exposure persists over a given period of time (generally 70 years for chronic effects),

4 HHRAP chapters are available at <http://www.epa.gov/osw/hazard/tsd/td/combust/risk.htm#hhrad>. See Chapter 7 for analyses methods.

5 See Table 1 at this EPA web site: <http://www.epa.gov/ttn/atw/toxsource/summary.html>.

adverse effects are considered unlikely. The individual hazard quotients were also summed to derive a cumulative hazard index value. Results of the cancer risk and non-cancer hazard assessments are presented below.

**Calculated Risk Summary**

Chemical	Annual Average Concentration (µg/m <sup>3</sup> )	EPA Risk Factors <sup>(a)</sup>		Calculated Cancer Risk	Calculated Non-Cancer Chronic HQ
		Cancer, Chronic (per µg/m <sup>3</sup> )	Non-Cancer Chronic HQ (µg/m <sup>3</sup> )		
Benzene	0.0635	7.80E-06	30.0	4.95E-07	2.12E-03
			Total =	4.95E-07	2.12E-03

(a) These chronic dose-response values are available at <http://www.epa.gov/ttn/atw/toxsource/table1.pdf>.

ARM 17.8.740(16) defines “negligible risk to the public health, safety, and welfare and to the environment” as “an increase in excess lifetime cancer risk of less than  $1.0 \times 10^{-6}$ , for any individual pollutant, and  $1.0 \times 10^{-5}$ , for the aggregate of all pollutants, and an increase in the sum of the non-cancer hazard quotients [e.g., hazard index] for all pollutants with similar toxic effects of less than 1.0, as determined by a human health risk assessment conducted according to ARM 17.8.767.” As shown, the results of this analysis are all well below these regulatory threshold values.

Increased cancer risk and the non-cancer hazard index were demonstrated to be far below the regulatory thresholds for negligible risk. This demonstration was made with combined worst case or conservative assumptions throughout the modeling and risk assessment. These assumptions included:

- Conservative screening level modeling utilizing AERSCREEN
- A person breathing the maximum concentration 24 hours per day, 365 days per year for 70 years

The results of this analysis demonstrate there would be negligible risk to public health from the operation of CHS’s product loadout VCU.

### III. BACT Determination<sup>6</sup>

A BACT determination is required for each new or modified source. CHS shall install on the new or modified source the maximum air pollution control capability, which is technically practicable and economically feasible, except that BACT shall be utilized.

CHS submitted a BACT analysis in MAQP application #1821-27, addressing some available methods for controlling emissions from each new or modified source. The following information and control options were reviewed by the Department in order to make the final BACT determination.

In this BACT analysis, a number of individual projects are discussed. First, the analysis discusses updates to two previously permitted refinery projects (Mild Hydrocracker Project (MHC) and the Benzene Reduction Unit (BRU) project). Secondly, the analysis will discuss the proposal to

<sup>6</sup> A significant portion of this BACT analysis has been replicated from *Application for Amendment of Air Quality Permit 1821-26 and Operating Permit OP1821-09, Mild Hydrocracker Project and Benzene Reduction Unit Project Updates, and Laurel Refinery Gasoline and Distillate Truck Loading Facilities, CHS, Inc., May 2012.*

construct new gasoline and diesel truck loading facilities. CHS provided information to show that none of the projects are technically or economically related (for PSD purposes, but were included in the same application for convenience).

**A. Mild Hydrocracker Project (MHC)**

CHS operates a FCCU, and this unit converts heavy hydrocarbons (e.g., gas oils) into lighter, more valuable materials, including gasoline and fuel oils. In general, the process involves injecting preheated feed into the catalyst Riser where it is vaporized and cracked into smaller molecules by contacting and mixing the feed with very hot powdered catalyst from the catalyst Regenerator. The hydrocarbon vapors fluidize the powdered catalyst and the mixture of hydrocarbon vapors and catalyst flows upward in the riser to the Reactor.

Within the Reactor, the cracked product vapors are separated from the “spent catalyst” through the use of cyclones. Spent catalyst flows downward through a steam stripping section to remove any hydrocarbons prior to the catalyst Regenerator. The cracked hydrocarbon is then separated into various intermediate products with the majority of the product being gasoline components. A light cycle oil is also produced, which is generally processed through the Ultra Low Sulfur Diesel (ULSD) Unit. The heaviest stream produced by the FCCU is clarified oil which is typically directed to the Delayed Coker Unit for additional processing. Note, a portion of the clarified oil (or other heavy material) could be recycled to the FCCU feed for temperature control within the FCCU process.

As a byproduct of the cracking process, carbon/coke deposits on the catalyst. As the carbon deposits on the catalyst surface, it becomes inactive (spent). As a result, catalyst is continuously regenerated by burning off the deposited coke with air blown into the Regenerator. The combustion of the coke produces a large amount of heat that is necessary for feed vaporization and the endothermic cracking reactions that take place in the catalyst Riser. The emissions from the catalyst regeneration process are primarily CO<sub>2</sub> along with parts per million levels of CO, NO<sub>x</sub>, SO<sub>2</sub>, VOC, and particulates. Presently, CHS uses an ESP to control FCCU Regenerator particulate emissions in addition to catalyst additives to control CO, NO<sub>x</sub>, and SO<sub>2</sub> emissions.

In a previous permit action, the Department approved the conversion of the HDS to a MHC. This project resulted in less FCCU feed being produced as well as a significant improvement in quality of the feed directed to the FCCU. As a result, there will be less coke being deposited on the catalyst and thus, less heat generated in the catalyst regeneration process. This will reduce the level of heat being transferred from the regenerator to the riser, by the catalyst, to support feed vaporization and cracking. In order to address the reduction in process heat generation, CHS proposed implementing two additional key changes within the FCCU as part of the MHC project: installation of a new FCC Charge heater with a higher firing rate than that previously approved (in MAQP #1821-22) but smaller than the existing FCC-Heater-1, and replacement of the FCCU Riser with a new Riser (and Riser design modifications).

With the proposed new FCCU Riser, the FCCU Reactor/Regenerator would be considered a modified unit. However, CHS provided information to show that while the unit would now be considered a modified unit there will be no change to the operation of the FCCU with regards to the reactor regenerator system; there will be no change in reliability; and there will be no increase in long or short-term emissions with the exception of CO emissions. However, CHS also believes the change in the riser design will improve the ability to control CO emissions from the Regenerator.

## **FCCU Regenerator**

As previously discussed above, a byproduct of the catalytic cracking process, carbon/coke deposits on the catalyst and as the catalyst surface is covered up, it becomes spent. As a result, the catalyst is continuously regenerated by burning off the deposited coke with air blown into the Regenerator.

CHS currently utilizes an ESP to control FCCU Regenerator particulate emissions and catalyst additives to control SO<sub>2</sub> emissions. Currently, CO emissions are controlled by maintaining a high enough temperature within the Regenerator and through the use of non-platinum CO combustion promoter. The primary reason non-platinum CO combustion promoter is used is to minimize NO<sub>x</sub> emissions.

As part of the consent decree (CD) (United States et al v. CHS Inc., Civil Action CV-03-153-BLG-RFC (D. Mont. February 23, 2004), CHS was required to establish permit limits for SO<sub>2</sub>, NO<sub>x</sub>, PM, and CO.

For CO and SO<sub>2</sub>, the CD specified the limits and these limits have been incorporated into the permit. For PM, CHS triggered applicability to 40 CFR 60, Subpart J as part of the Delayed Coker Project and CHS has incorporated the associated limits.

Additionally, the CD specified the maximum emission rate that control equipment, in this case the ESP, must be designed to achieve and set a timeline for implementation. Once the control equipment was operational, CHS was required to conduct performance tests and propose a PM limit to EPA. In accordance with the terms of the CD, CHS proposed a PM limit to the EPA on September 30, 2010. As of the date of this application, final concurrence on the proposed limit has not been received from EPA. Once a limit has been established, CHS will update the permit if it is different than the current limit.

For NO<sub>x</sub>, the CD provided two options. The first was to conduct NO<sub>x</sub> reducing catalyst additive trials, demonstrate the achievable NO<sub>x</sub> emission rate and incorporate emission limits based on the trials into the air permits. The second option was to accept emission limits specified in the consent decree and forego the additive trials. CHS chose to conduct the additive trials and has incorporated NO<sub>x</sub> permit limits resulting from the trials. The table below summarizes the current CHS FCCU Regenerator control methods and emissions limits.

<b>Summary of the CHS FCCU Regenerator Control Methods and Emissions Limits</b>		
<b>Pollutant</b>	<b>Control Method</b>	<b>Emissions Limits</b>
CO and VOC	Full burn operation with good combustion practices; non-platinum CO combustion promoter addition	<ul style="list-style-type: none"> <li>• 500 ppm at 0% O<sub>2</sub> per 1-hour time period</li> <li>• 100 ppm<sub>vd</sub> at 0% O<sub>2</sub>, on a 365-day rolling average basis</li> </ul>
NO <sub>x</sub>	Hydrotreated feed; NO <sub>x</sub> -reducing catalyst additives	<ul style="list-style-type: none"> <li>• 65.1 ppm<sub>vd</sub> at 0% O<sub>2</sub> on a 365-day rolling average applicable at all times</li> <li>• 102 ppm<sub>vd</sub> at 0% O<sub>2</sub> on a 7-day rolling average basis, except during periods of startup, shutdown, malfunction and hydrotreater outages</li> </ul>
SO <sub>2</sub>	Low sulfur feed; SO <sub>2</sub> reducing catalyst additives	<ul style="list-style-type: none"> <li>• 50 ppm SO<sub>2</sub> by volume (corrected to 0% O<sub>2</sub>) on a 7-day rolling average</li> <li>• 25 ppm<sub>vd</sub> at 0% O<sub>2</sub> on a 365-day rolling average basis</li> </ul>
PM/PM <sub>10</sub> /PM <sub>2.5</sub>	ESP (filterable)	<ul style="list-style-type: none"> <li>• 1.0 lb PM/1000 lb of coke burned</li> </ul>

## **CO and VOC BACT Analysis for FCCU Regenerator**

In review of available control options, CHS considered only those associated with a full-burn unit (e.g., not partial burn units with associated CO boilers). The following control options were identified:

Good combustion practices. The combustion of coke occurs first through the oxidation of carbon to CO and then by CO combustion to CO<sub>2</sub>. The activation energy for CO combustion is considerably higher than for carbon combustion such that CO combustion is usually the rate-limiting step in the process. If the FCCU Regenerator temperature is not high enough (e.g., good combustion practice), the CO to CO<sub>2</sub> reaction rate can be too slow, resulting in a significant increase in rate of CO emissions.

CO combustion promoter. CO combustion promoter is an additive used to increase the CO combustion rate. Because the heat release from CO combustion is about three times greater than the heat release from carbon combustion to CO, it is important that the CO combustion occurs within the dense bed of the catalyst. Without the catalyst bed to absorb this heat of combustion, the flue-gas temperature increases very rapidly, resulting in “afterburning”. Use of CO combustion promoter increases the CO combustion rate causing the CO to burn in the catalyst bed so that afterburning is controlled to acceptable levels. The benefit of this control includes extended mechanical life of downstream equipment, lower carbon on regenerated catalyst, better utilization of air and decreased catalyst deactivation.

The use of CO oxidation catalyst was also identified via technology transfer from natural gas fired combustion turbines. The platinum based catalyst used to accomplish oxidation is also very active with respect to its ability to oxidize SO<sub>2</sub> to SO<sub>3</sub>. As a result, it is not used to reduce CO and VOC emissions in situations where there is a measureable amount of SO<sub>2</sub> in the exhaust gas. As a result, the platinum based catalyst was eliminated from this evaluation based upon its technical feasibility because of the SO<sub>2</sub> containing exhaust from the FCCU.

Two remaining CO and VOC emissions control technologies identified above are currently being used at CHS. As a final check, CHS compared its existing CO concentration limits with the CO concentration limits at other full-burn FCCU Regenerators utilizing the same controls and there were no other facilities with lower CO limits than those in place at CHS. CHS also submitted information on two full-burn FCCU Regenerators with mass emission rate limits for VOC. However, CHS currently does not have VOC emission limits and requested that the existing CO limits continue to be used as a surrogate for VOC because of their relationship to each other (i.e., same control options).

Because the current controls and emission limits seem to be in line with other FCCU Regenerators, CHS proposed and the Department concurs, that the existing CO concentration limits constitutes BACT. In addition, the Department previously determined that the CO and VOC emissions from the FCCU Regenerator stack shall be controlled through the use of CO combustion promoters and good combustion practices and that compliance with the FCCU Regenerator Stack CO emission limits could be used as surrogate for VOCs.

## **NOx BACT Analysis for FCCU Regenerator**

As discussed above, CHS' FCCU is a full-burn unit whereby the coke on the catalyst is completely combusted to CO<sub>2</sub> and water in the regenerator (e.g., only trace amounts of CO are produced). Thus, a downstream combustion unit (e.g., CO boiler) would not be necessary. CHS believes that the installation of potentially applicable NOx emissions controls on a downstream boiler represents a completely different application than installation of these controls downstream of a full-burn FCCU regenerator. Therefore, the analysis focused on NOx control options from a full-burn unit.

In FCCUs nitrogen oxides are formed by two different mechanisms. A small portion of the NOx is thermal, and is generated as a result of the high temperature oxidation of molecular nitrogen in the combustion air. The remaining NOx, which originates in the FCCU feed, is formed by the oxidation of char nitrogen present in the coke--on the catalyst. The concentration of nitrogen in the FCCU feed is a function of basic nitrogen levels in the crude being processed and the level of upstream pretreatment (e.g., the CHS HDS Unit removes nitrogen bound to the carbon containing molecules in the feed as part of the hydrogenation process). However, the rate of emissions has been shown to change with feed rate, feed properties, and other process parameters. Other major influences on NOx production include the quantity and distribution of oxygen in the regenerator and whether a CO combustion promoter is used. Another important factor is temperature.

Based on the review of the information available, the following NOx control options were identified as commercially available and technically feasible.

Feedstock hydrotreatment. Nitrogen in the feed to the FCCU is one source of the Regenerator NOx emissions. However, CHS currently hydrotreats the FCCU feed in HDS unit, resulting in reduced nitrogen in the feed. With implementation of the MHC project, the feed nitrogen will be significantly reduced from current levels because the MHC would hydrotreat the feed even more. CHS reports that this will result in lower baseline NOx emissions from the unit. At this time, it is unclear the degree to which this will occur until the unit begins operation. As such, no further discussion of this control option is provided.

Good combustion control. As previously discussed above, FCCU Regenerator NOx is believed to be formed from the high temperature oxidation of molecular nitrogen in the combustion air and oxidation of char nitrogen present in the coke on the catalyst. Generally speaking, higher combustion temperatures and higher excess air concentrations increase NOx emissions and decrease emissions of CO and VOC. Thus, proper operation and control of regenerator combustion conditions can be key to controlling emissions of NOx. CHS noted in the application that they currently use good combustion control to balance NOx and CO emissions. As such, no further discussion of this control option is provided.

Catalyst additives. NOx-reducing catalyst additives are designed to promote reactions in the FCCU Regenerator without effects on yield, CO afterburn, or other important operating parameters. The effectiveness of NOx-reducing catalysts varies from unit to unit.

Two classifications of additives are available. The first is a low-NOx, CO combustion promoter, which causes the CO to burn in the catalyst bed so that afterburning is controlled to acceptable levels. The benefits of this control include extending the mechanical life of downstream equipment, lower carbon on regenerated catalyst, improved utilization of air and decreased catalyst deactivation. However, CO

combustion promoters (e.g., standard platinum-based promoters) are known to increase NOx emissions by as much as 300%. It is believed that this is caused by the rapid oxidation of CO to CO<sub>2</sub>, which in turn means that there is no CO available to reduce the NOx which is formed. Replacing the typical CO combustion promoters with a low-NOx (non-platinum) CO combustion promoter has been shown to reduce NOx emissions. Non-platinum promoter slows the rate at which CO is oxidized to CO<sub>2</sub> and allows the reduction reaction between CO and NOx time to occur. The second type of catalyst additive used to reduce NOx formation works by influencing the NOx formation reaction pathways in the FCCU. In accordance with the CD, CHS was required to conduct trials using low-NOx CO combustion promoter and NOx-reducing catalyst additives. The results of the trials were used to set the existing FCCU Regenerator NOx concentration limits at the demonstrated lowest possible NOx emissions rates on a short and long-term basis. For this reason, the use of catalyst additive(s) is considered the baseline control option for the purposes of this BACT analysis.

Selective Catalytic Reduction (SCR). SCR is a post-combustion NOx control technology that involves injecting ammonia into high temperature flue gas flowing through a fixed catalyst bed. The process temperature needs to be approximately 600 - 800°F to promote a reaction between NOx and ammonia in order to produce nitrogen and water. The primary components of the system are: the reagent storage, delivery, vaporization and injection system; and the SCR catalyst reactor and related support equipment.

One other NOx control technology, Low Temperature Oxidation (LoTOx) was identified as potentially applicable but was excluded from further review because it is considered an add-on technology to a wet gas scrubber. Because CHS does not currently utilize a wet gas scrubber for control of SO<sub>2</sub> or PM emissions, it was removed from further consideration.

Currently, CHS uses three of the four technically feasible NOx control options identified and discussed above. For this reason, CHS compared the current use of NOx-reducing catalyst additives in the FCCU with the expected performance of an SCR. There are several refineries that utilize an SCR to control NOx emissions from the full-burn FCCU Regenerator. The majority of those units have the following flue gas NOx concentration limits:

- 20 ppmvd @ 0% O<sub>2</sub>, 365 day rolling average
- 40 ppmvd @ 0% O<sub>2</sub>, 7 day rolling average

CHS has concentration limits of 65.1 ppmvd @ 0% O<sub>2</sub>, 365 day rolling average and 102 ppmvd @ 0% O<sub>2</sub>, 7-day rolling average which were established based on the results of consent decree catalyst additive trials. To evaluate whether the installation of an SCR is considered economically feasible, CHS estimated post project annual NOx emissions assuming a NOx concentration of 20 ppmvd (the assumed BACT NOx level with SCR) and the maximum expected FCCU Regenerator stack flow after MHC Project implementation. In addition, CHS calculated the post project annual NOx emissions using the current NOx concentration limit and the maximum expected FCCU Regenerator stack flow rate after MHC Project implementation. The difference between the two numbers (55.2 TPY) is the amount of NOx reduced with the installation of an SCR.

CHS provided information in the application to show that the cost to install and to operate an SCR would be approximately \$12,800/ton of NOx removed. Based upon this, the use of SCR is not economically feasible.

Based on this information, CHS proposed that the existing NO<sub>x</sub> concentration limits of 65.1 ppm<sub>vd</sub> at 0% O<sub>2</sub> on a 365-day rolling average, and 102 ppm<sub>vd</sub> at 0% O<sub>2</sub> on a 7-day rolling average basis constitute BACT. CHS also requested that these limits would not apply during periods of startup, shutdown, malfunction, and hydrotreater outages, but did not provide supporting information to change the long term limit. The short term limit applies at all times except during periods of startup, shutdown, malfunction or hydrotreater outages. Therefore, the Department determined that following limits constitutes BACT for NO<sub>x</sub>:

- NO<sub>x</sub> emissions from the FCCU Regenerator Stack shall not exceed 65.1 ppm<sub>vd</sub> at 0% oxygen on a 365-day rolling average basis during all times. This long-term limit shall apply at all times (including during startup, shutdown, malfunction, and hydrotreater) that the FCCU Regenerator Stack is operating.
- NO<sub>x</sub> emissions from the FCCU Regenerator Stack shall not exceed 102 ppm<sub>vd</sub> at 0% oxygen on a 7-day rolling average basis. This short-term limit shall exclude periods of startup, shutdown, malfunction or hydrotreater outages, but shall apply at all other times that the FCCU is operating.

### **SO<sub>2</sub> BACT Analysis for FCCU Regenerator**

SO<sub>2</sub> originates from sulfur present in the FCCU feed. The majority of the gas oil feed for the CHS FCCU is produced in the HDS Unit. The HDS Unit significantly reduces the sulfur content in the FCCU feed. CHS anticipates that the level of sulfur in the FCCU feed will be reduced further when the HDS Unit is converted to a MHC Unit.

The following three SO<sub>2</sub> control options were identified as commercially available and technically feasible:

Low sulfur feed. As discussed previously, CHS currently processes low sulfur feed in the FCCU. The MHC Project will result in a significant reduction in the current level of sulfur in the feed.

SO<sub>2</sub>-reducing catalyst additives. CHS currently utilizes SO<sub>2</sub>-reducing catalyst additives to reduce SO<sub>2</sub> emissions from the FCCU Regenerator. The additive is mixed with the fresh catalyst and added to the FCCU process, typically as a percentage of the fresh catalyst feed rate. After the MHC Project is completed, CHS anticipates little or no SO<sub>2</sub>-reducing catalyst additive will be required.

Wet gas scrubber. With a wet gas scrubber, caustic base solution is added to the regenerator flue gas and is routed to a separation system. The “scrubbed” flue gas travels upward and the scrubber solute carrying the pollutants travels downward. Typically, the flue gas passes through a clean spray of water to remove remaining solids followed by a grid to remove water droplets. A portion of the solute is recycled and reused in the wet gas scrubber and the remaining solute is treated before it can be reused or discharged.

CHS utilizes two of the three SO<sub>2</sub> control options discussed above. For this reason, CHS compared the current use of SO<sub>2</sub>-reducing catalyst additives in the FCCU with the expected performance of a wet gas scrubber. There are a significant number of refineries that utilize a wet gas scrubber to control SO<sub>2</sub> emissions, but the majority of those units have the same flue gas SO<sub>2</sub> concentration limits as CHS (e.g., 25 ppm<sub>vd</sub> @ 0% O<sub>2</sub>, 365 day rolling average, and 50 ppm<sub>vd</sub> @ 0% O<sub>2</sub>, 7 day rolling average). However according to CHS, there is only one with a more stringent limit (HOVENSA, 16 ppm<sub>vd</sub> @ 0% O<sub>2</sub>, 365 day rolling average, and 25 ppm<sub>vd</sub> @ 0% O<sub>2</sub>, 7 day rolling average).

CHS estimated post project annual SO<sub>2</sub> emissions assuming an SO<sub>2</sub> concentration of 16 ppmvd and the maximum expected FCCU Regenerator stack flow after MHC Project implementation to evaluate whether the installation of a WGS would be economically feasible. CHS also calculated the post project annual SO<sub>2</sub> emissions using the current SO<sub>2</sub> concentration limit and the maximum expected FCCU Regenerator stack flow rate after MHC Project implementation. A difference of 17.4 TPY resulted and this is the amount of SO<sub>2</sub> reduced that would result with the installation of a WGS. WGS is also identified as effective in removing PM, and CHS calculated that WGS would result in a PM reduction of 6.8 TPY. CHS used PM emissions in their cost evaluation and therefore, assumed the total emissions reduced due to the installation of WGS would be 24.2 TPY.

Estimates provided by CHS show that the cost to install and operate a WGS on the CHS FCCU Regenerator to control both SO<sub>2</sub> and condensible PM emissions would be approximately \$79,000/ton of pollutant removed. Based on this, WGS was removed from further consideration.

Therefore, CHS proposed that the existing SO<sub>2</sub> concentration limits of 25 ppmvd @ 0% O<sub>2</sub>, 365 day rolling average and 50 ppmvd @ 0% O<sub>2</sub>, 7 day rolling average constitute BACT for the FCCU Regenerator and the Department agrees with this determination.

#### **PM, PM<sub>10</sub> and PM<sub>2.5</sub> BACT Analysis for FCCU Regenerator**

PM and non-condensable PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the FCCU regenerator originates from the uncombusted soot and airborne catalyst fines in the regenerator exhaust gas. Condensable PM<sub>10</sub> and PM<sub>2.5</sub> is formed when oxidized sulfur species (e.g, SO<sub>2</sub> and SO<sub>3</sub>) combine with moisture in the regenerator exhaust gas to form H<sub>2</sub>SO<sub>4</sub> (sulfuric acid) and water.

Currently, PM and filterable PM<sub>10</sub> and PM<sub>2.5</sub> emissions are currently being controlled by mechanical cyclones within the FCCU Regenerator followed by an Electrostatic Precipitator (ESP), and are limited to 1.0 lb/1,000 lb coke burned pursuant to 40 CFR 60, Subpart J. This Subpart requires test Method 5B to demonstrate compliance, but this measures only the filterable portion of PM and PM<sub>10</sub>. Currently, CHS does not have a control method, limit or monitoring requirement for condensable PM emissions.

Based on the review of the information sources available, the following three PM control options were identified as commercially available and technically feasible for refinery FCCU Regenerators:

**Third Stage Separator.** This mechanical separator can be installed downstream of the FCCU Regenerator to remove catalyst, catalyst fines and uncombusted soot (all filterable particulates). It is most effective in removing larger particles however it does not control condensable PM emissions.

**ESP.** An ESP removes filterable PM from flue gas using the force of an induced electrostatic charge. They are highly energy efficient filtration devices that only minimally impede the flue gas flow and are effective at removing fine particles from the flue gas stream. An ESP only applies energy in the form of electricity to the particulate matter being collected and ESPs do not control condensable PM emissions.

**Wet Gas Scrubber.** With a wet gas scrubber, caustic based scrubber solution is added to the regenerator flue gas and is routed to a separation system. The “scrubbed” flue gas travels upward and the solute carrying the pollutants travels down. The flue gas typically passes through a clean spray of water to remove remaining solids and then through a grid

to remove water droplets. A portion of the solute is recycled and reused in the wet gas scrubber. The remaining solute requires treatment before it can be reused or discharged. Wet gas scrubbers are effective at removing both filterable and condensable PM.

CHS currently utilizes an ESP to control PM emissions from the FCCU Regenerator. For this reason, CHS compared the effectiveness of the remaining two control options with the effectiveness of an ESP.

As background, during implementation of the CD, CHS was required to install and use PM control equipment designed to achieve a PM emission limit of 0.50 lb PM/1000 lb of coke burned. During this process, it was determined that a Third Stage Separator could not meet the design requirements. This was primarily based on the particle size distribution of the particulates in the flue gas (e.g, third stage separator is not as efficient in removing smaller particles). As such, CHS elected to install an ESP to meet the CD design requirement.

Based on this information, CHS compared the actual performance of the ESP to the expected performance of a WGS. As stated above, several refineries utilize a wet gas scrubber to control PM (and other) emissions from FCCU Regenerators. According to the RACT/BACT/LAER Clearinghouse (RBLC) database, the refineries with limits expressed as lb PM/1000 lb coke burned have emission limits ranging from 0.3 – 1.0 lb/1000 lb coke burned. CHS assumed that these limits apply to only filterable PM and PM<sub>10</sub> as CHS is not aware of any refinery FCCU that has testing requirements for the condensable PM fraction. One facility in the database has an ESP identified as its PM control method with a limit of 1.334 lb/ton coke burned (or 0.665 lb PM/1000 lb coke burned) and CHS has a limit of 1.0 lb PM/1000 lb coke burned. As stated above, this is the limit CHS proposed to EPA, as required by the CD (1.0 lb PM/1000 lb coke burned), and is based on the actual performance of the ESP rather than the design of the ESP. Based on this review, CHS has concluded that for control of filterable PM emissions, an ESP and wet gas scrubber are comparable technologies.

CHS evaluated the cost effectiveness of installing a wet gas scrubber to remove the condensable PM. Based on the results of one onsite test, CHS estimates that the condensable portion of the CHS FCCU Regenerator total PM is between 15 – 20%. Using the projected FCCU coke make following implementation of the MHC Project, CHS estimates a maximum condensable PM emission rate of approximately 6.8 TPY. For this analysis, CHS has assumed that a WGS would remove all of the condensable PM from the flue gas stream. As mentioned above, WGS is also identified as effective in removing SO<sub>2</sub>, so the SO<sub>2</sub> reduction attributable (17.4 TPY) to the installation of a WGS must also be considered in the cost effectiveness evaluation. Therefore, the total emission reduced that would be attributable to the installation of a WGS is 24.2 TPY.

CHS provided information to show that the cost to install and operate a WGS on the CHS FCCU Regenerator to control both SO<sub>2</sub> and condensable PM emissions is approximately \$79,000/ton of pollutant removed. Based upon this result, WGS is not considered cost effective.

The only technically feasible control alternative for condensable PM was eliminated. As such, CHS proposed that the existing filterable PM limit of no greater than 1.0 lb/1000 lb coke burned on a 3-hr rolling average constitutes BACT for the FCCU Regenerator at the Laurel Refinery. Based on this information, the Department determined that the following is BACT: PM emissions from the FCCU Regenerator Stack shall be controlled with an ESP and shall not exceed 1.0 lb PM/1,000 lb of coke burned, based on a 3-hour rolling average.

### **FCC Charge Heater (FCC-Heater-NEW)**

The new FCCU Charge Heater will be fired using refinery fuel gas and will have a maximum process heat input of 66 MMBtu-HHV/hr. The proposed heater is a source of fuel combustion related emissions, including nitrogen oxides (NO<sub>x</sub>), sulfur dioxide (SO<sub>2</sub>), carbon monoxide (CO), volatile organic compounds (VOC), and particulate matter (PM/PM<sub>10</sub>).

### **NO<sub>x</sub> BACT Analysis for the FCC-Heater-NEW<sup>7</sup>**

Nitrogen oxides are formed as part of the combustion process and are generally classified in accordance with their formation mechanism as either thermal NO<sub>x</sub> or fuel NO<sub>x</sub>. Thermal NO<sub>x</sub> is formed by the thermal dissociation and subsequent reaction of the nitrogen and oxygen in the combustion air at high temperature. Usually, the amount of thermal NO<sub>x</sub> formation is a function of the burner, the process heater or boiler's fire box/combustion chamber design, flame temperature, residence time at flame temperature, combustion pressure, and fuel/air ratios in the primary combustion zone. The rate of thermal NO<sub>x</sub> formation is an exponential function of the flame temperature.

Fuel NO<sub>x</sub> is formed by the gas phase oxidation of the nitrogen that is chemically bound (e.g. CN compounds) in the fuel (e.g., char nitrogen). Fuel NO<sub>x</sub> formation is largely independent of combustion temperature and the nature of the organic nitrogen compound. Its formation is dependent on fuel nitrogen content and the amount of excess combustion air (i.e., the excess oxygen beyond the fuel's stoichiometric requirement). Refinery gas contains negligible amounts of fuel bound nitrogen. As such, thermal NO<sub>x</sub> is the predominant type of NO<sub>x</sub> that will be formed in the FCC Charge heater.

Based on the information provided by CHS, the following NO<sub>x</sub> control technologies were identified as commercially available for refinery process heaters:

- Low nitrogen fuels;
- Water-injection style burners;
- Combustion Control (e.g., Standard Burners with Air to Fuel (A/F) ratio control);
- Low-NO<sub>x</sub> burners (LNB);
- Ultra Low-NO<sub>x</sub> burners (ULNB) including burners with internal or external flue gas recirculation (FGR);
- Next Generation Ultra Low-NO<sub>x</sub> burners including burners with lean premix technology combined with external flue gas recirculation;
- EMx (formerly SCONO<sub>x</sub>);
- Non-Selective Catalytic Reduction (NSCR) (post-combustion exhaust treatment);
- Selective Non-Catalytic Reduction (SNCR) (post-combustion exhaust treatment);  
and
- SCR (post-combustion exhaust treatment).

The above control strategies can be classified as pre-combustion (e.g., fuel type), combustion modification (e.g., burner design), and post-combustion (e.g., add-on control). Pre-combustion control strategies typically involve switching to other fuels with lower nitrogen contents or removing nitrogen from the fuel with a treatment technology. Since there is little if any fuel bound nitrogen in refinery fuel gas, low fuel bound nitrogen/fuel treatment is not considered in this analysis.

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<sup>7</sup> A significant portion of this BACT analysis has been replicated from an email sent to the Department (on July 12, 2012) to supplement the *Application for Amendment of Air Quality Permit 1821-26 and Operating Permit OP1821-09, Mild Hydrocracker Project and Benzene Reduction Unit Project Updates, and Laurel Refinery Gasoline and Distillate Truck Loading Facilities, CHS, Inc., May 2012.*

EPA ranked the NO<sub>x</sub> control technologies that can be applied to refinery process heaters (see the Tier 2 BACT/LAER Memorandum dated January 19, 2001 and titled *BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Project* for more information).

Selective Non-Catalytic Reduction (SNCR), or ammonia injection, is considered technically infeasible in these applications because of the temperature zone requirements for SNCR to be effective. Two commercially available SNCR technologies, Thermal DeNOX® and NOXOUT® SNCR, both depend on controlled temperatures in the range of 1600 – 1900°F. The exhaust temperature of each new heater will be well below this range. Additionally, this option represents a technology transfer (e.g. large-scale boiler control technology to smaller heaters) that has only been commercially demonstrated on one U.S. refinery process heater, according to EPA’s Tier 2 Report.<sup>8</sup> As such, SNCR is not considered a feasible control option and was removed from consideration.

Process Heater BACT Control Hierarchy for NO <sub>x</sub>					
Technology	Range of Emission Levels Reported, in ppmv or % reduction, as applicable	Emission Level Used in Analysis		% Reduction Relative to Uncontrolled (Natural Draft Heater)	Technically Feasible?
		ppmv <sup>d</sup>	lb/MMBtu		
SCR + Combustion Controls	4 to 12 ppmv	7	0.0085	92	Yes
SNCR + Combustion Controls	No process heater data for combination. Combustion controls are 25 to 50 ppmv, SNCR alone is 30 to 75 percent reduction <sup>b</sup>	13	0.015	85	No
SCR	80 - 95% reduction <sup>b</sup>	18	0.022	80	Yes
Combustion Control <sup>a</sup>	20 – 50 ppmv <sup>a</sup>	40 <sup>b</sup>	0.04	68	Yes
SNCR	30 -75% reduction <sup>c</sup>	72	0.087	19	No
No Control - Natural Draft Heater	--	89	0.11	--	--

<sup>a</sup> This represent the best burner designs for reducing NO<sub>x</sub> emissions that are commercially available for use on process heaters. These burner designs incorporate internal FGR.

<sup>b</sup> New FCCU Charge Heater.

<sup>c</sup> This percent reduction is relative to a mechanical draft heater.

<sup>d</sup> Parts per million (ppm) by volume, dry basis, at three percent oxygen.

For the top-listed feasible NO<sub>x</sub> control technology, SCR plus combustion controls, CHS has shown that the incremental cost-effectiveness of adding an SCR system to an ULNB system is greater than \$31,000 per ton of NO<sub>x</sub> removed. These costs are on a 2001 cost basis. If the 2001 costs were escalated to a 2012 basis, it was determined that the

<sup>8</sup> Tier 2 BACT Report, prepared by Eastern Research Group for U.S. EPA, January 2001.

incremental cost effectiveness would be even higher. CHS has determined that these costs are considered infeasible and, for this reason, SCR was rejected as NOx BACT. (Note: the use of SCR without combustion controls is not considered feasible or realistic for the heater because the ULNBs that the heater is equipped with are considered inherent to its design).

The combustion control, ULNB option, is proposed to achieve NOx BACT limits for the new FCCU Charge Heater. The following information describes the expected performance of the ULNB on the FCC Charge Heater on a short and long term basis.

Burner manufacturers have indicated that a NOx performance level of 0.035 lb/MMBtu-HHV is technically achievable for the new FCCU Charge Heater. However, this performance guarantee is based on a specified fuel composition, typical operating range (e.g., range of firing rates), specified excess oxygen and specified ambient temperature range. In addition, the guarantee is based on stable operation and not the operation expected during startup/shutdown and other periods of transition in the operation (e.g., significant changes in the process heat input requirements from the FCC Charge Heater). As such, the burner manufacturer's specified NOx performance level of 0.035 lb/MMBtu-HHV is considered to be achievable on an annual average basis (e.g., 365 day rolling average).

There are a number of independent factors that are known to impact the short term NOx emission rate including the variability of the refinery fuel gas composition and the actual firing rate of the heater. These factors are not accounted for in a heater or burner vendor's performance guarantee. As a result, CHS expects that a NOx emission rate of 0.04 lb/MMBtu-HHV is achievable on a short term basis<sup>9</sup>. The impact that the variability of refinery fuel gas composition and a heater's relative firing rate have on NOx emissions is discussed below.

Variability of Refinery Fuel Gas Composition. At CHS, the sour RFG is generated within various process units. Each of the RFG streams generated at a given unit has a different composition and as a result different combustion characteristics. The sour RFG is treated to remove sulfur compounds and routed to a common RFG mix drum. On a short-term basis, the mix drum provides for a fairly consistent RFG composition, and in general, a more stable operation of the combustion sources. However, on a long term basis, the RFG composition can vary significantly, due to operational changes within the individual production units that contribute RFG to the overall RFG system. For example, if one production unit is shut down, the composite RFG characteristics will change to reflect the absence of that fuel in the RFG.

CHS completed a review of the NOx CEMs and fuel gas composition data for Boiler 11 to determine the impact that fuel composition, specifically hydrogen and propylene/ethylene content, has on the NOx emissions rate. As a result, CHS has shown that the hydrogen and propylene/ethylene content in the refinery RFG system during the past year and the hydrogen content has varied between 10 and 35 percent while the propylene/ethylene content has varied between 2.5 and 9.5 percent.

Additionally, CHS provided information showing the relationship between hydrogen content and NOx emissions whereby the NOx increases with hydrogen content. This impact on NOx is consistent with what would be expected because hydrogen has a much higher flame temperature than methane, which is a primary component of RFG. CHS

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<sup>9</sup> For the annual average refinery fuel gas composition at the CHS Refinery, this nearly equates to the NSPS Subpart Ja limit of 40 ppmv (dry basis, corrected to 0 percent excess air) on a 24-hour rolling average basis.

noted that hydrogen has many favorable combustion characteristics, including zero CO<sub>2</sub> emissions and extremely high flame speed, which gives it exceptional combustion stability.

Similar to hydrogen, increasing quantities of propylene/ethylene in the RFG results in increased NO<sub>x</sub> formation. With the variability of hydrogen and propylene/ethylene content in the RFG, CHS requested that the Department consider the above information and the fact that NO<sub>x</sub> guarantee is based on a static fuel composition.

NO<sub>x</sub> Performance over Range of Firing Rates. The new FCC Charge Heater will provide a portion of the heat necessary for the FCCU cracking process. There are several factors that will impact how much heat will be required at any given time including the FCCU feed quality and feed rate. As the quality of the feed improves, more heat input will be required on a per barrel basis for the cracking process. The quality of the feed is dictated by the operations in upstream operating units and market conditions. Additionally, assuming consistent feed quality, more process heat input will be required at higher FCCU feed rates.

Through review of process heater performance test data, CHS observed a strong correlation between the NO<sub>x</sub> emission rate and the actual firing rate relative to its design firing rate (e.g., % of design firing rate). As expected, because the rate of NO<sub>x</sub> emissions are controlled by the level of internal exhaust gas recirculation within the low NO<sub>x</sub> burner, the NO<sub>x</sub> emission performance improves as the heater's firing rate increases. For this reason, CHS also requested that the Department consider the variability in a heater's actual firing rate as part of the permitting process.

In summary, CHS proposed that the FCC-Heater-NEW be fitted with ULNB and that the NO<sub>x</sub> emissions limit be based on 40 ppm<sub>v</sub> (dry basis, corrected to 0 percent excess air) on a 24-hour rolling average basis (40 CFR 60, Subpart Ja). However, on September 12, 2012 (after the PD was issued) the stay was lifted on 40 CFR 60, Subpart Ja. Based on the new information, CHS has requested that the BACT limit be changed accordingly: NO<sub>x</sub> emissions limit be based on 40 ppm<sub>v</sub> (dry basis, corrected to 0 percent excess air) on a 30-day rolling average basis (40 CFR 60, Subpart Ja).

Based on the above information, the Department has determined that the following constitutes BACT. The FCC Charge Heater (FCC-Heater-NEW) shall be equipped with an ULNB and the heating input shall not exceed 66 MMBtu/hr-HHV based on a 30-day rolling average. Additionally, the Department determined that the BACT NO<sub>x</sub> emission limits are as follows:

- 40 ppmv (dry basis, corrected to 0 percent excess air) on a 30-day rolling average basis.
- 0.035 lb/MMBtu-HHV, or 10.1 TPY based on a rolling 12-calendar month.
- 0.04 lb/MMBtu-HHV, or 2.6 lb/hr based on an hourly rolling 24-hour average.

### **SO<sub>2</sub> BACT Analysis for the FCC-Heater-NEW**

As previously mentioned above, the SO<sub>2</sub> emissions from process heaters are a direct function of the sulfur content of the fuel that is burned. Reduced sulfur compounds in the fuel are readily oxidized to SO<sub>2</sub> and to a small extent SO<sub>3</sub>. In the new process heater, CHS plans to use low sulfur refinery fuel gas, which will further limit SO<sub>2</sub> emissions from this unit.

Emissions of SO<sub>2</sub> from process heaters can be controlled by fuel specifications or by using post-combustion controls. Fuel specifications limit SO<sub>2</sub> emissions by specifying a maximum allowable sulfur concentration in the gaseous fuels combusted in the process heater. Post-combustion control for SO<sub>2</sub> involves treating the combustion gases with an alkaline reagent that reacts with the SO<sub>2</sub> to produce a sulfur salt byproduct (e.g., sodium sulfite). This type of post-combustion control process is Flue Gas Desulfurization (FGD). FGD technology is well-established for sources with relatively high levels of sulfur emissions. It has not been used on refinery process heaters, generally because fuel gas desulfurization is a more cost-effective means of reducing SO<sub>2</sub> emissions. Each of these control techniques is discussed further below.

Gaseous Fuel Specifications / Use of Natural Gas only. Pipeline quality natural gas has very low sulfur content, generally in the form of mercaptans (at about 4 ppmv) used for “odorization,” and the gas may also contain trace quantities of reduced sulfur compounds (a few grains/100 scf). SO<sub>2</sub> emissions from natural gas-fired equipment are generally considered the lowest practically achievable for that fuel and do not require additional control equipment.

Gaseous Fuel Specifications / Use of Low-sulfur Refinery Gas. Refinery fuel gas has a higher sulfur content than the natural gas purchased from a pipeline. The refinery gas sulfur content is dependent on the removal efficiency of the fuel gas amine scrubbing units in a refinery. CHS plans to continue to operate the existing amine scrubbing system to produce refinery gas with less than 60 ppmv H<sub>2</sub>S, on an annual average basis (40 CFR 60, Subpart Ja). On a short-term basis, variability in the operation of the amine scrubbing system may result in spikes in the sulfur concentration of the lean gas produced (e.g., as much as 162 ppmv sulfur on a 3-hour average basis).

Flue Gas Desulfurization. FGD is commonly used for control of SO<sub>2</sub> from solid fuel-combustion, such as coal. FGD technology can be achieved through a variety of wet or dry scrubbing processes. Generally speaking, it has control efficiencies of up to 95 percent on coal-fired combustion systems.

The use of FGD technology is not considered technically feasible for the new FCCU Charge Heater because the heater would have to be significantly altered, to a mechanical draft design, to provide the flue gas pressure required for adding an FGD system. In addition, FGD technology is not commercially demonstrated on small refinery process heaters because it is cost-prohibitive compared to the cost of desulfurizing the fuel gas (in this case, via the use of an amine scrubbing system).

The top-performing feasible SO<sub>2</sub> control technology is the firing of 100% purchased natural gas in the heater, because of the very low sulfur content of natural gas. The next most effective control technology is the use of refinery fuel gas treated to sulfur levels that meet the recently finalized 40 CFR 60, Subpart Ja. Therefore, this was used as the baseline for SO<sub>2</sub> emissions from the new process heater.

The table below presents the cost effectiveness of firing natural gas vs. refinery fuel gas in the proposed new heater. For the natural gas firing scenario, the table shows a cost effectiveness of \$1.52 million/ton SO<sub>2</sub>, based on a natural gas price of approximately \$3/MMBtu. As a result, this option is not considered economically feasible, and is rejected as BACT.

### Results of FCC Charge Heater SO<sub>2</sub> Control Cost Analyses

Control Alternative	SO <sub>2</sub> Emissions (TPY)	SO <sub>2</sub> Emissions Reduction (TPY)	Total Annualized Cost (\$10 <sup>6</sup> /yr) <sup>b</sup>	Average Cost Effectiveness (\$10 <sup>6</sup> /ton SO <sub>2</sub> controlled) <sup>b</sup>	Environ. Impacts (Yes/No)	Energy Impacts (Yes/No)
Natural gas firing	0.2	1.9	1.73	0.91	No	Yes
Refinery gas firing (baseline)	2.1	---	---	---	---	---

<sup>b</sup> Calculations:

\$1.73 million/yr = [66 MMBtu/hr (HHV)] x (8,760 hr/yr) x (\$3.00/mmBtu N.G.) / (1 million)

\$0.91 million/ton SO<sub>2</sub> controlled = (\$1.73 million/yr) / (1.9 tons SO<sub>2</sub> controlled/yr)

Based on information provided, CHS requested the following as BACT:

CHS shall not burn in the FCC Charge Heater (FCC-Heater-NEW) any fuel gas that contains H<sub>2</sub>S in excess of 60 ppmv determined daily on a 365-successive calendar day rolling average basis. The Department has determined that this meets the requirements of 40 CFR 60, Subpart Ja and is consistent with other Department BACT determinations for process heaters.

#### **CO and VOC BACT Analysis for the FCC- Heater-NEW**

Emissions of CO and VOC (including organic HAPs) from process heaters are the result of incomplete combustion. Other factors that play a role in CO formation include: operating conditions such as low temperatures; insufficient residence time; low oxygen levels due to inadequate mixing; and/or a low air-to-fuel ratio in the combustion zone. CO emissions increase may occur at reduced firing rates due to lowering of flame temperatures and less efficient combustion. VOC emissions result from incomplete combustion of the heavier molecular weight components of the refinery gas fuel. In addition, VOC emissions are produced to some degree by the reforming of hydrocarbon molecules in the combustion zone.

Emission control methods for CO and VOC that are commercially available for refinery process heaters and boilers include (in order of increasing control effectiveness):

- Burner Design and Operation;
- Fuel Specifications (use of natural gas, or LPG, or refinery gas);
- Catalytic Oxidation; and
- EMx (formerly SCONOX).

The following is a discussion of the above-listed CO and VOC emission control systems or techniques potentially applicable to process heaters and boilers.

**Burner Design and Operation.** Proper burner design to achieve good combustion efficiency in heaters and boilers will minimize the generation of CO and VOC. Good combustion practices are accomplished by proper hardware design and operating procedures. A firebox design that provides an adequate residence time, temperature and combustion zone turbulence, in combination with proper control of air-to-fuel ratio, are essential elements of a low-CO and low-VOC technology.

Ultra Low NO<sub>x</sub> burner technology has advanced significantly, and as a result, emitting units are showing decreased NO<sub>x</sub> and CO emissions. However, there is a trade-off between NO<sub>x</sub> and CO emissions. For instance, tuning an ULNB for both low NO<sub>x</sub> and low CO can result in unsteady emissions or an unsteady flame. However, while trying to achieve lower NO<sub>x</sub> there is always a possibility that CO emissions will not be minimized. Conversely, an ULNB can be tuned for lower CO emissions but at the cost of increased NO<sub>x</sub>. Achieving low CO becomes especially problematic in large vertical, cylindrical furnaces where temperatures are stratified, thus allowing cool spots for CO to form. VOC emissions do not tend to be as sensitive to low NO<sub>x</sub> levels as CO but can still be similarly affected. Examination of the RBLC database indicates that implementation of combustion design and operating principles to minimize CO and VOC emissions are the only applied BACT measure for process heaters.

Gaseous Fuel Specifications / Use of Natural Gas Only. Gaseous fuels have differing compositions and specifications that can affect the ability of ULNB technology to achieve complete combustion. Pipeline natural gas is a fuel predominantly comprised of methane. An odorant is added to allow easy leak detection of the otherwise odorless gas. Natural gas is processed to meet certain specifications so that combustion parameters are relatively consistent throughout most of the country. These parameters include percent methane, heating value, and sulfur content. The consistent fuel characteristics of natural gas allow ULNBs to operate with the lowest guaranteed VOC and CO emissions.

Refinery fuel gas is a byproduct of the refining operations and is generally consumed on-site. It may contain significant proportions of fuel components other than methane, such as hydrogen, ethane, propane, and butanes. However, it is not economically feasible to make the refinery gas meet a specification that is comparable to pipeline natural gas specifications. As such, VOC and CO emission guarantees for ULNBs firing refinery gas may not be as low as guarantees for ULNBs firing natural gas.

However, there is no measurable difference in the CO and VOC emissions that would result from burning 100% natural gas instead of refinery fuel gas, which has a very similar composition to natural gas. In addition, as previously mentioned in the SO<sub>2</sub> BACT sections above, burning natural gas in this heater is economically prohibitive. Therefore, this control option is rejected from consideration as BACT.

Catalytic Oxidation. Catalytic oxidation of CO and VOC gases requires a catalyst bed located in the heater or boiler exhaust. These systems are available as modular units that can be integrated into the exhaust duct or stack. For maximum conversion, catalytic oxidation requires elevated temperature conditions for catalytic oxidation of CO, typically between 800°F and 1,200°F. Oxidation of VOCs occurs efficiently in a lower temperature range of 300°F to 800°F. In some cases, the temperature criterion limits adaptability to process units and reduces the potential for heat recovery. However, there are newer catalyst systems available that extend the practical temperature range.

Reduction efficiencies of 90% and 50% are typical for CO and VOC, respectively. However, the reduction efficiency for VOC is compound specific.

Oxidation catalysts use precious metal based catalysts to promote the oxidation of CO and unburnt hydrocarbon to CO<sub>2</sub>. Refinery fuel gas contains sulfur as H<sub>2</sub>S, which when burned oxidizes to SO<sub>2</sub>. Oxidation catalyst is not applied to sources where sulfur bearing fuels are fired because much of the SO<sub>2</sub> formed by the combustion process is further oxidized to SO<sub>3</sub> which readily becomes sulfuric acid mist (H<sub>2</sub>SO<sub>4</sub>·2H<sub>2</sub>O) in the

atmosphere. This increase in sulfuric acid mist would increase plume visibility and increase the amount of PM<sub>10</sub>/PM<sub>2.5</sub> emitted. The sulfuric acid would also cause corrosion of the control equipment and stack.

Additionally, precious metals which are the active components in oxidation catalyst are subject to irreversible poisoning when exposed to sulfur compounds. The only known application of oxidation catalyst to refinery gas fired combustion devices is a combustion turbine application in Southern California firing a mix of refinery gas and natural gas. There are no known applications of oxidation catalyst applied to refinery process heaters. As such, this control option is not considered technically feasible nor is it demonstrated for this type of application, and is rejected from consideration as BACT.

EMx. EMx is the second generation of SCONOX NOx absorber technology. EMx is a catalyst-based post-combustion control, which simultaneously oxidizes CO to CO<sub>2</sub>, VOC to CO<sub>2</sub> and water, and NO to NO<sub>2</sub>, subsequently adsorbing the NO<sub>2</sub> onto the surface of a catalyst where a chemical reaction removes it from the exhaust stream.

To date, EMx has only been demonstrated on natural-gas fired combustion turbines. The technology has not been demonstrated on other emissions unit types, and has not been demonstrated on units that fire refinery fuel gas. As such, EMx is not considered to be demonstrated in practice on this source category (e.g. refinery fuel gas fired process heaters), and is removed from consideration as BACT for the control of CO and VOC emissions.

The only remaining CO and VOC control option is proper burner design and operation. The CO emission estimate for the heater is based on 100 ppm<sub>vd</sub> @ 3% O<sub>2</sub> (0.066 lb CO/MMBtu-HHV). According to EPA's RBL database for heaters and boilers, the CO emission limits range from 0.050 to 0.110 lb CO/MMBtu. CHS proposes compliance with this CO level by controlling the combustion temperature, residence time, and available oxygen. Normal combustion practices at the CHS refinery will involve maximizing the heating efficiency of the fuel in an effort to minimize fuel usage. This will also minimize CO and VOC formation. As such, no BACT emission limit is proposed for VOC.

Consistent with all CO and VOC BACT determinations for RFG-fired sources found in the RBL, proper design and good combustion techniques constitute CO and VOC BACT for the FCC Charge Heater. In addition, CHS requested that the Department retain the current condition for startup and shutdown that had been previously established.

In summary, the Department agrees that proper design and good combustion techniques constitutes BACT for the new heater to minimize CO, VOC, and PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions. Additionally, based on information provided in the application, the Department also determined that a CO limit of 100 ppm<sub>vd</sub> at 3% O<sub>2</sub> on a 24-hour average basis constitutes BACT for CO.

#### **PM/PM<sub>10</sub>/PM<sub>2.5</sub> BACT Analysis for the FCC-Heater-New**

Particulate matter emissions from process heaters with properly designed and tuned burners are inherently low when gaseous fuels are used. Filterable particulate matter in gas-fired sources that are properly tuned originates from the dust in the inlet air and metal erosion within the sources (e.g., tubes, combustion surfaces, etc.). Sources that are not properly tuned may also produce filterable particulate matter as a result of incomplete combustion of fuel hydrocarbons that agglomerate to form soot particles. These particles

pass through the firebox and are emitted in the exhaust gas. Condensable particulate matter can result from oxidation of fuel sulfur (to sulfur trioxide) and from incomplete combustion of hydrocarbons in the fuel. For the purposes of this BACT analysis, all of the particulate matter emitted from the proposed process heaters is assumed to be PM<sub>10</sub> and PM<sub>2.5</sub>. The following provides a summary of the BACT analysis provided by CHS:

**Good Combustion Control.** Proper combustor design and operation to achieve good combustion efficiency in heaters and boilers will minimize the generation of CO, VOC, and filterable particulate matter. Good combustion efficiency relies on both hardware design and operating procedures. A firebox design that provides proper residence time, temperature, and combustion zone turbulence in combination with proper control of the air-to-fuel ratio, are essential elements of good combustion control.

**Gaseous Fuel Specifications.** A common form of particulate matter control from combustion sources is the requirement to use a specified gaseous fuel (e.g., natural gas). Whereas solid fuel (e.g., coal) produces a larger amount of particulate matter, gaseous fuels are considered “clean” with respect to generation of particulate matter emissions. Gaseous fuels have differing specifications, depending on their source. Natural gas is processed to meet certain specifications such that the key combustion parameters (i.e., percent methane, heating value, and sulfur content) are relatively consistent in most parts of the country. PM/PM<sub>10</sub> emissions from properly designed and controlled natural gas-fired equipment are generally considered the lowest achievable.

Refinery fuel gas is a byproduct of refining operations that is typically processed and consumed on-site. As a result, it is not possible to meet pipeline natural gas composition specifications. With proper burner design and operation, refinery fuel gas-fired sources can achieve PM/PM<sub>10</sub> emission levels that approach those of natural gas. Combustion of refinery fuel gas will result in slightly higher PM/PM<sub>10</sub> emissions than combustion with natural gas because of the higher molecular weight hydrocarbons (propane and butane) and the presence of sulfur compounds. The presence of higher molecular weight hydrocarbons in refinery fuel gas makes it more difficult to properly tune the burner to minimize the formation of particulates. The higher level of sulfur compounds in refinery fuel gas results in production of more SO<sub>3</sub>, a compound that contributes to condensable particulate matter emissions.

**Baghouse.** A baghouse removes particulate from an exhaust stream by passing the gas through a fabric filter bags that are periodically cleaned using any of a number of techniques such as high-pressure reverse flow air pulses, high intensity sonic horns and shaking. A baghouse is generally capable of achieving the lowest particulate emission rates of any type of add-on particulate control device.

**Electrostatic Precipitator.** An electrostatic precipitator (ESP) uses electrodes to collect particulate by imparting a static electric charge on the particles as they pass through the high intensity electric field called a corona that forms around the corona wire. The particles are then attracted to and collect on electrically charged plates. These plates are periodically “rapped” by solenoid-activated weights that rap on the top end of the plates to dislodge the collected particles. The material then falls by gravity into hoppers below the ESP and is removed for disposal. The ability of an ESP to remove particulate matter depends in large part on the electrical properties of the particle itself and the sulfur content of the particle directly impacts those properties. Inorganic particles that are higher in sulfur content are more electrically conductive and are very readily collected by an ESP. In contrast, soot particles formed by condensation after partial combustion of gaseous fuel, have relatively lower sulfur content and are essentially non-conductive. Electrostatic collectors do not readily capture these particles.

The size of the particulate is also of great concern since very small soot particles are influenced almost equally by impacts with gaseous molecules or electrostatic forces, and will be less efficiently captured. Capture is more efficient with larger particles. Although ESPs can also achieve very low particulate emission rates, the achievable emission rates from an ESP are higher than the particulate concentration expected from the combustion of gaseous fuels. As such, ESPs are not used for particulate control for combustion devices burning natural/refinery gas.

The use of baghouses and ESPs for post-combustion controls is common on residual oil and coal-fired combustion units that require significant particulate matter reduction, and which typically have much higher particulate loading, solid particle sulfur content, and larger sized particles. Baghouses and ESPs have not been used for particulate control for combustion devices burning gaseous fuels such as natural gas or refinery fuel gas.

Fabric filters rely on the build-up of a filter cake to act as a filtering medium for collection of particulate matter. Periodically, this filter cake is removed, and filtration efficiency declines until a filtering cake can be re-established. The ultra-fine size of particulate emissions from firing of gaseous fuels is such that no cake could be established in a fabric filter. Instead, the very fine particles would be expected to either pass through the bags uncontrolled, or they would “blind” filter bags fairly quickly, resulting in unacceptable pressure drops and requiring impossibly frequent bag replacement.

ESPs rely on the ability of a particle to acquire an electrical charge. Once charged, the particles migrate from the flue gas to oppositely charged plates where they deposit. The deposits are removed by “rapping” the plates and they settle by gravity to collection hoppers. The organic nature of the ultra-fine particulates generated by gaseous fuel combustion is such that acquiring the necessary electrical charge is difficult. ESPs also rely on gravity settling of the collected particulates. The fine particles produced in gas-fired heaters are such that gravity settling is unlikely to occur and any particles collected on the plates would likely be re-entrained in the flue gas as the plates are rapped.

While Baghouses/ESPs are theoretically feasible for application to gas-fired process heaters, fabric filters and ESPs are not considered technically feasible for the control of the PM/PM<sub>10</sub> emissions from the gas fired heater and have been removed from further consideration.

As such, the top-performing feasible PM/PM<sub>10</sub> control technology would be the firing of purchased natural gas in the heater, because the very low sulfur content of natural gas will result in low condensable PM<sub>10</sub> and PM<sub>2.5</sub> emissions relative to the use of typical RFG. The next most effective technically feasible PM control option is the use of good combustion practices in combination with firing gaseous fuels.

For the heater, CHS calculated the cost of firing purchased natural gas in place of RFG to be greater than \$18 million/ton PM<sub>10</sub> or PM<sub>2.5</sub> reduced, based on a natural gas price of approximately \$3/MMBtu. This option is considered to be cost infeasible, and was rejected as BACT.

Consistent with all PM/PM<sub>10</sub> BACT determinations for RFG-fired sources found in the RBLC, CHS proposed proper design and good combustion techniques as BACT for the FCC-Heater-NEW and the Department concurs.

## **B. Benzene Reduction Unit**

The recent 1000 Unit Hydrogen Plant expansion completed with the BRU Project (MAQP #1821-18) involved the addition of a steam superheater and an Enhanced Heat Transfer Reformer (EHTR). The superheater supplies additional heat to the reformer via a higher inlet process gas temperature. This allowed for an increase in the process feed gas flow at the same reformer heat duty. The EHTR is a recuperative heat-exchanging reactor that utilizes heat from the reformer effluent to convert additional feed to hydrogen.

CHS reported that following the 1000 Unit Hydrogen Plant expansion, the characteristics of the PSA tailgas changed (e.g. the heat content (in Btu/scf) and the volume produced increased (in scfm). The total heat input (in MMBtu/hr) associated with the PSA tailgas remained nearly the same. As a result, the existing PSA tailgas burners on the H-1001 Reformer Heater could not handle the increased volume of PSA tailgas without excessive pressure drop and the 1000 Unit Hydrogen Plant production rate was limited by the volume of PSA tailgas that could be combusted. In this permit action, CHS proposed to eliminate the restriction on the H-1001 Reformer Heater by replacing the PSA tailgas burner tips with tips that have larger ports.

The H-1001 Reformer Heater is an existing process heater. It is an induced draft, down-fired furnace with 24 burners. After the modification, the heater will have a maximum firing capacity of 174.4 MMBtu-LHV/hr (approximately 191.8 MMBtu-HHV/hr) with the normal firing rate expected to be approximately 151 MMBtu-LHV/hr (approximately 167 MMBtu-HHV/hr). During normal operation, a purge gas stream generated within the 1000 Unit Hydrogen Plant, PSA tailgas, will provide approximately 70% of the fuel to the H-1001 Reformer Heater. Natural gas or RFG will provide the remaining fuel heat input during normal operation and will be used exclusively during unit startup.

In addition to eliminating the restriction on the heater, this project will also replace the burner tips for the supplemental fuel with an improved design intended to achieve a reduced NO<sub>x</sub> emission rate. Replacement of the burners in H-1001 is considered a modification and triggers 40 CFR 60, Subpart Ja for fuel gas combustion devices.

### **NO<sub>x</sub> BACT Analysis for H-1001 Reformer Heater**

As discussed above, nitrogen oxides are formed as part of the combustion process and are generally classified in accordance with their formation mechanism as either thermal NO<sub>x</sub> or fuel NO<sub>x</sub>. Refinery gas contains negligible amounts of fuel bound nitrogen. As such, thermal NO<sub>x</sub> is the predominant type of NO<sub>x</sub> that is formed in H-1001.

The following NO<sub>x</sub> control technologies were identified as commercially available for refinery process heaters:

- Low nitrogen fuels;
- Water-injection style burners;
- Combustion Control (e.g., Standard Burners with Air to Fuel (A/F) ratio control);
- Low-NOx burners (LNB);
- ULNB including burners with internal or external FGR;
- Next Generation Ultra Low-NOx burners including burners with lean premix technology combined with external flue gas recirculation;
- EMx (formerly SCONOx);
- NSCR (post-combustion exhaust treatment);
- SNCR (post-combustion exhaust treatment); and
- SCR (post-combustion exhaust treatment).

The above control strategies can be classified as pre-combustion, combustion modification, and post-combustion. Pre-combustion control strategies typically involve switching to other fuels with lower nitrogen contents or removing nitrogen from the fuel with a treatment technology. Since there is little if any fuel bound nitrogen in refinery gas, low fuel bound nitrogen/fuel treatment is not considered in this analysis.

SNCR. SNCR, or ammonia injection, is considered technically infeasible in this application because of the temperature zone requirements for SNCR to be effective. Two commercially available SNCR technologies, Thermal DeNOX® and NOXOUT® SNCR, both depend on controlled temperatures in the range of 1600 – 1900°F. The exhaust temperature of the H-1001 Reformer Heater is well below this range. This option represents a complex technology transfer (large-scale boiler control technology to smaller heaters) that has only been commercially demonstrated on one refinery process heater in the U.S., according to EPA's Tier 2 Report.<sup>10</sup> As such, SNCR is not considered a feasible control option.

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<sup>10</sup> Tier 2 BACT Report, prepared by Eastern Research Group for U.S. EPA, January 2001.

Process Heater BACT Control Hierarchy for NO <sub>x</sub>					
Technology	Range of Emission Levels Reported, in ppmv or % reduction, as applicable	Emission Level Used in Analysis		% Reduction Relative to Uncontrolled (Mechanical Draft Heater)	Technically Feasible?
		ppmv <sup>b</sup>	lb/MMBtu		
SCR + Combustion Controls	4 to 12 ppmv	7	0.0085	96	Yes
SNCR + Combustion Controls	No process heater data for combination. Combustion controls are 23 to 33 ppmv, SNCR alone is 30 to 75 percent reduction	13	0.015	93	No
SCR	80 - 95% reduction	18	0.022	90	Yes
Combustion Control <sup>a</sup>	20 - 50 ppmv <sup>a</sup>	29	0.035	84	Yes
SNCR	30 -75% reduction	72	0.087	60	No
No Control - Mechanical Draft Heater	--	89	0.11	--	--

<sup>a</sup> These represent the best burner designs for reducing NO<sub>x</sub> emissions that are commercially available for use on process heaters. These burner designs incorporate internal FGR.

<sup>b</sup> Parts per million (ppm) by volume, dry basis, at three percent oxygen.

For the top-listed feasible NO<sub>x</sub> control technology, SCR plus combustion controls, CHS provided information to show that the incremental cost-effectiveness of adding an SCR system to an ULNB system is greater than \$22,000 per ton of NO<sub>x</sub> removed. These costs were derived using a 2001 cost basis and if adjusted to current, the incremental cost effectiveness would be higher. This cost estimate is based on a new installation, not the retrofit of an existing heater. The cost to retrofit an existing heater with an SCR system would be higher than an entirely new installation. These costs are economically not feasible, and for this reason, SCR was rejected as NO<sub>x</sub> BACT for the H-1001 Reformer Heater. CHS also noted that the use of SCR without combustion controls is not considered feasible or realistic because the H-1001 Reformer Heater is currently equipped with ULNB.

As such, the combustion control (ULNB) option is proposed as NO<sub>x</sub> BACT for the modified H-1001 Reformer Heater. Through the review of heater design and process conditions, the burner manufacturer specified (and demonstrated with a test unit) that a NO<sub>x</sub> performance level of 0.035 lb NO<sub>x</sub>/MMBtu-HHV (365-day rolling average) is technically achievable for the modified H-1001 Reformer Heater.<sup>11</sup> This emission rate is guaranteed for the range of normal to maximum heat release (68 MMBtu-HHV to 192

<sup>11</sup> As part of MAQP 1821-23, CHS permitted H-102 based on a NO<sub>x</sub> emission rate of 0.030 lb/MMBTU. H-102 is a different design than the existing H-1001 Reformer Heater and utilizes PSA tailgas for up to 80% of its fuel heat input (MMBtu/hr). H-1001 will utilize PSA tailgas for approximately 70% of its fuel. Performance of low NO<sub>x</sub> burners improves (e.g, the NO<sub>x</sub> rate reduces) as the percent of PSA tailgas in the fuel increases.

MMBtu-HHV/hr), and will, therefore, be achievable on an annual average basis.<sup>12</sup> CHS also supplied supplemental information to the Department (on July 2, 2012) to support a short term NO<sub>x</sub> limit of 0.04 lb/MMBtu-HHV for normal operations to account for variability in the refinery's fuel gas composition. According to CHS, there are a number of factors that impact the heater's short term NO<sub>x</sub> emissions which are not accounted for in the vendor's guarantees. The design of a heater and its burners are based on specified fuel composition, typical operating range, specified excess oxygen, and specified ambient temperature ranges. In general, guarantees are based on stable operation and not operation that might occur during startup/shutdown and other transitional operations (e.g. changes in hydrogen production rate).

Based on the information provided by, the Department determined that 0.04 lb NO<sub>x</sub>/MMBtu-HHV (or 7.7 lb/hr) based on a 24-hour rolling average, and 0.035 lb NO<sub>x</sub>/MMBtu-HHV (or 29.4 TPY) based on a 12-calendar month total constitutes BACT for the H-1001 Reformer Heater.

### **SO<sub>2</sub> BACT Analysis for the H-1001 Reformer Heater**

SO<sub>2</sub> emissions from process heaters are a direct function of the sulfur content of the fuel that is burned. Reduced sulfur compounds in the fuel are readily oxidized to SO<sub>2</sub> and to a small extent SO<sub>3</sub>. In H-1001 Reformer Heater, CHS uses sulfur free pressure-swing absorber (PSA) tailgas, natural gas and refinery fuel gas, which will continue to limit SO<sub>2</sub> emissions from this unit.

Emissions of SO<sub>2</sub> from process heaters can be controlled by fuel specifications or by using post-combustion controls. Fuel specifications limit SO<sub>2</sub> emissions by specifying a maximum allowable sulfur concentration in the gaseous fuels combusted in the process heater. Post-combustion control for SO<sub>2</sub> involves treating the combustion gases with an alkaline reagent that reacts with the SO<sub>2</sub> to produce a sulfur salt byproduct (e.g., sodium sulfite). This type of post-combustion control process is generally termed Flue Gas Desulfurization (FGD). FGD technology is well-established for sources with relatively high levels of sulfur emissions. It has not been used on refinery process heaters, generally because fuel gas desulfurization is a more cost-effective means of reducing SO<sub>2</sub> emissions. Each of these control techniques is discussed further below.

Gaseous Fuel Specifications / Use of Natural Gas only. Pipeline quality natural gas has very low sulfur content, generally in the form of mercaptans (at about 4 ppmv) used for "odorization," and the gas may also contain trace quantities of reduced sulfur compounds (a few grains/100 scf). SO<sub>2</sub> emissions from natural gas-fired equipment are generally considered the lowest practically achievable for that fuel and do not require additional control equipment.

Gaseous Fuel Specifications / Use of Low-sulfur Refinery Gas. Refinery fuel gas typically has higher sulfur content than the natural gas purchased from a pipeline. The refinery gas sulfur content is dependent on the removal efficiency of the fuel gas amine-based scrubbing units in a refinery. It is expected that, on average during normal heater operation, approximately 70% of the BTUs required for the heater will come from PSA tailgas, a process stream produced within the hydrogen purification section of the 1000 Unit Hydrogen Plant. PSA tailgas is comprised of CO<sub>2</sub>, CO, methane, N<sub>2</sub> and H<sub>2</sub>. PSA tailgas contains no sulfur compounds because it is generated as part of the reforming

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<sup>12</sup>To account for variability in refinery fuel gas composition, CHS has calculated short term NO<sub>x</sub> emission rates for normal operations based on 0.04 lb/MMBtu-HHV. The NO<sub>x</sub> CEM being added with the project will provide actual NO<sub>x</sub> emission rates during the gradual and controlled heat up of the unit and during shutdown. Based on this data, CHS may be required to modify this BACT review to account for NO<sub>x</sub> emissions during startup and shutdown.

process that converts natural gas to hydrogen. Because sulfur is a poison to the catalyst used in the reforming process, the natural gas feed stream is first passed through sulfur absorbers to remove any sulfur or sulfur containing compounds. As a result, the byproduct PSA tail gas contains no sulfur. The remaining fuel that will be fired in H-1001 will be RFG, if available, or natural gas. CHS operates the existing amine-based scrubbing system to produce refinery fuel gas with less than 60 ppmv H<sub>2</sub>S, on an annual average basis. On a short-term basis, variability in the operation of the amine scrubbing system may result in spikes in the sulfur concentration of the lean gas produced (e.g., as much as 162 ppm<sub>v</sub> sulfur on a 3-hour average basis).

Flue Gas Desulfurization. FGD is commonly used for control of SO<sub>2</sub> from solid fuel-combustion, such as coal or heavy oil fired sources. FGD technologies are available and demonstrated in a variety of wet or dry scrubbing configurations. They have demonstrated control efficiencies of up to +95 percent on coal-fired combustion systems.

However, FGD technology is not commercially demonstrated on small refinery process heaters because it is not cost effective compared to desulfurizing the fuel gas with the use of an amine scrubbing system. In addition, removing the sulfur from the fuel rather than the exhaust gas allows much lower SO<sub>2</sub> levels in the exhaust to be achieved. As a result, FGD technology is removed from consideration.

The top-performing feasible SO<sub>2</sub> control technology is to maximize the firing of sulfur-free PSA tailgas in the heater, with the remainder of the fuel required being purchased natural gas, because of the very low sulfur content of natural gas. The next most effective control technology is to maximize the firing of sulfur-free PSA tailgas in the heater, with the remainder of the fuel required being amine treated refinery fuel gas (RFG) that meets 40 CFR 60, Subpart Ja. As such, the combination of PSA tailgas and RFG is considered baseline for SO<sub>2</sub> emissions from the H-1001 Reformer Heater.

The table below presents the cost and cost effectiveness of firing a combination of PSA tailgas and natural gas versus firing a combination of PSA tailgas and RFG. For the PSA tailgas and natural gas firing scenario, the table shows a cost effectiveness of \$1.41 million/ton SO<sub>2</sub>, based on a natural gas price of approximately \$5/MMBtu. As a result, this option is not considered cost effective, and is rejected as BACT.

<b>Results of H-1001 Reformer Heater SO<sub>2</sub> Control Cost Analysis</b>						
<b>Control Alternative</b>	<b>SO<sub>2</sub> (TPY)</b>	<b>SO<sub>2</sub> Emissions Reduction (TPY)</b>	<b>Total Annualized Cost (\$10<sup>6</sup>/yr)<sup>b</sup></b>	<b>Ave. Cost Effectiveness (\$10<sup>6</sup>/ton SO<sub>2</sub>)<sup>b</sup></b>	<b>Environ. Impacts (Yes/No)</b>	<b>Energy Impacts (Yes/No)</b>
28% NG/ 72% PSA tailgas <sup>a</sup>	0.13	1.67	2.35	1.41	No	Yes
28% RFG/ 72% PSA tailgas <sup>a</sup> (baseline)	1.80	---	---	---	---	---

<sup>a</sup>Gas percentages are on a heat input basis (365-day rolling average).

NG = Natural Gas

PSA = Pressure Swing Absorption

RFG = Refinery Fuel Gas

<sup>b</sup> Calculations:

\$2.35 million/yr = [191.8 MMBtu/hr (HHV)] x (28% natural gas) x (8,760 hr/yr) x (\$5.00/mmBtu N.G.) / (1 million)

\$1.41 million/ton SO<sub>2</sub> controlled = (\$2.35 million/yr) / (1.67 tons SO<sub>2</sub> controlled/yr)

CHS proposed the following as BACT for SO<sub>2</sub> and the Department concurred.

- All available 1000 Unit PSA purge gas shall be fired in the H-1001 Reformer Heater
- No sulfur in the PSA purge gas
- Refinery fuel gas H<sub>2</sub>S content of 60 ppmv (based on a 365-day rolling average)

### **CO and VOC Analysis for H-1001 Reformer Heater**

Emissions of CO and VOC (including organic HAPs) from process heaters result from incomplete fuel combustion. Operating conditions such as low temperatures, insufficient residence time, low oxygen levels due to inadequate mixing, and/or a low air-to-fuel ratio in the combustion zone result in CO formation. CO emissions may also increase at reduced firing rates due to lowering of flame temperatures and less efficient combustion. VOC emissions result from incomplete combustion of the heavier molecular weight components of the refinery gas fuel. In addition, VOC emissions are produced to some degree by the reforming of hydrocarbon molecules in the combustion zone.

During turndown and shutdown operations, the heater experiences an increase in CO emissions. This phenomenon is a result of ULNB design/low firebox temperatures that are unable to force completion of fuel oxidation, which would convert all of the carbon in the fuel being fired to CO<sub>2</sub>. During startup operations, there is a heat-up period where the heater must remain at low rates as the heater internals heat up. This is done gradually to prevent thermally shocking the materials in the heater, which could result in damage. CO emissions are higher during startups because of the incomplete combustion caused by the entrainment of cold furnace gases into the flame, as well as higher heat loss to the cold furnace walls. This problem is particularly prevalent in ultra low NO<sub>x</sub> burners that incorporate large amounts of furnace gas entrainment into the flames.

Control options for CO and VOC generally consist of fuel specifications, combustion modification measures, or post-combustion controls. Fuel specifications for refinery process heaters have stipulated the use of natural gas or liquefied petroleum gas (LPG). These fuels have very consistent compositions/heating values that make it easier to tune

the burners. Also, the hydrocarbon make up of the fuel (percentage of hydrogen, methane, propane, etc.) can affect the impact of uncombusted fuel on the flue gas VOC content. Combustion controls (proper design and operation) are the most typical means of controlling VOC and CO emissions. Improper burner operation or design is a common cause of excess emissions of these two pollutants. For gaseous fuel combustion sources, oxidation catalyst may be used to complete the oxidation of CO and VOC to carbon dioxide and water.

Emission control methods for CO and VOC that are commercially available for refinery process heaters and boilers include, in order of increasing control effectiveness are discussed in more detail below:

- Burner Design and Operation
- Fuel Specifications (use of natural gas, or LPG, or refinery gas)
- Catalytic Oxidation
- EMx (formerly SCONOx)

Burner Design and Operation. Implementation of proper burner design to achieve good combustion efficiency in heaters and boilers will minimize the generation of CO and VOC. Good combustion efficiency relies on both hardware design and operating procedures. A firebox design that provides proper residence time, temperature and combustion zone turbulence, in combination with proper control of air-to-fuel ratio, is essential for a low-CO and low-VOC technology.

Ultra Low NOx burner technology has advanced significantly, driving down both NOx and CO emissions to lower levels. However, at some level a trade-off exists between low NOx and low CO emissions. Attempting to tune an ULNB for both low NOx and low CO can result in unsteady emissions or an unsteady flame, neither of which is desirable. While tuning a burner to achieve lower NOx, the possibility exists that CO emissions will not be minimized. Conversely, an ULNB can be tuned for lower CO emissions at the cost of increased NOx. VOC emissions do not tend to be as sensitive to low NOx levels as CO but can still be similarly affected. Examination of the RBLC database indicates that implementation of combustion design and operating principles to minimize CO and VOC emissions are the only applied BACT measure for process heaters.

Gaseous Fuel Specifications / Use of Natural Gas Only. Depending on their source, gaseous fuels have differing compositions and specifications that can affect the ability of ULNB technology to achieve complete combustion. Pipeline natural gas as supplied in the United States is a fuel predominantly comprised of methane. An odorant is added to allow easy leak detection of the otherwise odorless gas. It is processed to meet certain specifications such that key combustion parameters are relatively consistent throughout most of the country. These parameters include percent methane, heating value, and sulfur content. The consistent fuel characteristics of natural gas allow ULNBs to operate with the lowest guaranteed VOC and CO emissions.

Refinery fuel gas is a byproduct of the refining operations and is generally consumed on-site. It may contain significant proportions of fuel components other than methane, such as hydrogen, ethane, propane, and butanes. Because it is a byproduct of various refinery processes with varying compositions between streams, it is not economically feasible to make the refinery gas meet a specification that is comparable to pipeline natural gas specifications. As a result, on a day in day out basis, expected VOC and CO emissions for ULNBs firing refinery gas may not be as low as expected for ULNBs firing natural gas.

However, there is no measurable difference in the CO and VOC emissions that would result from burning 100% natural gas instead of refinery fuel gas, which has a very similar composition to natural gas. In addition, as previously mentioned in the SO<sub>2</sub> BACT sections, burning natural gas in this heater is economically prohibitive. As a result, this control option is rejected from consideration as BACT.

Catalytic Oxidation. Catalytic oxidation of CO and VOC gases requires a catalyst bed located in the heater or boiler exhaust. These systems are available as modular units that can be integrated into the exhaust duct or stack. For maximum conversion, catalytic oxidation requires elevated temperature conditions for catalytic oxidation of CO, typically between 800°F and 1,200°F. Oxidation of VOCs occurs efficiently in a lower temperature range of 300°F to 800°F. In some cases, the temperature criterion limits adaptability to process units and reduces the potential for heat recovery. However, there are newer catalyst systems available that extend the practical temperature range. Reduction efficiencies of 90% and 50% are typical for CO and VOC, respectively. The reduction efficiency for VOC is compound specific.

Oxidation catalysts have traditionally been applied to the control of CO emissions from natural gas fired combustion turbines located in CO nonattainment areas. This technology uses precious metal based catalysts to promote the oxidation of CO and unburnt hydrocarbon to CO<sub>2</sub>. Refinery fuel gas contains sulfur as H<sub>2</sub>S, which when burned oxidizes to SO<sub>2</sub>. Oxidation catalyst is not applied to sources where sulfur bearing fuels are fired because much of the SO<sub>2</sub> formed by the combustion process is further oxidized to SO<sub>3</sub> which readily becomes sulfuric acid mist (H<sub>2</sub>SO<sub>4</sub>·2H<sub>2</sub>O) in the atmosphere. This increase in sulfuric acid mist results in an increase in plume visibility and increase the amount of PM<sub>10</sub>/PM<sub>2.5</sub> emitted. The sulfuric acid would also cause corrosion of the control equipment and stack, thus, oxidation catalyst is not considered feasible for this application.

In addition, the precious metals which are the active components in oxidation catalyst are subject to irreversible poisoning when exposed to sulfur compounds. The only known application of oxidation catalyst to refinery gas fired combustion devices is a combustion turbine application in Southern California firing a mix of refinery gas and natural gas. There are no known applications of oxidation catalyst applied to refinery process heaters. As such, this control option is not considered technically feasible nor is it demonstrated for this type of application, and is rejected from consideration as BACT.

EMx. EMx is the second generation of SCONOX NOx absorber technology. EMx is a catalyst-based post-combustion control, which simultaneously oxidizes CO to CO<sub>2</sub>, VOC to CO<sub>2</sub> and water, and NO to NO<sub>2</sub>, subsequently adsorbing the NO<sub>2</sub> onto the surface of a catalyst where a chemical reaction removes it from the exhaust stream.

To date, EMx has only been demonstrated on natural-gas fired combustion turbines. The technology has not been demonstrated on other emissions unit types, and has not been demonstrated on units that fire refinery fuel gas. As such, EMx is not considered to be demonstrated in practice on this source category (e.g., refinery fuel gas fired process heaters), and is removed from consideration as BACT for the control of CO and VOC emissions.

Based on this, the remaining CO and VOC control option is proper burner design and operation. The CO emission estimate for H-1001 is based on 0.02 lb CO/MMBtu-HHV. This compares with other CO limits for heaters and boilers listed in EPA's RBLC database, where CO limits range from 0.050 to 0.110 lb CO/MMBtu. Compliance with this CO level will be accomplished by controlling the combustion temperature, residence

time, and available oxygen. Normal combustion practices at the CHS refinery will involve maximizing the heating efficiency of the fuel in an effort to minimize fuel usage. This efficiency of fuel combustion will also minimize CO and VOC formation. As such, CHS did not propose a BACT limit for VOCs. CHS proposed proper design and good combustion techniques as CO and VOC BACT for the modified heater, and reported that this is consistent with all CO and VOC BACT determinations for RFG-fired sources found in the RBLC.

Based on the information presented, the Department determined that 0.02 lb CO/MMBtu-HHV (or 16.8 TPY) based on a rolling 12-calendar month total, and 0.04 lb CO/MMBtu-HHV (or 7.7 lb/hr) during periods of startup and shutdown based on an hourly rolling 24-hr rolling average constitutes BACT. In addition, CO, VOC and PM/PM<sub>10</sub> emissions shall be controlled by proper design and good combustion practices.

PM/PM<sub>10</sub>/PM<sub>2.5</sub> BACT Analysis. Particulate matter emissions from process heaters with properly designed and tuned burners are inherently low when gaseous fuels are used. Filterable particulate matter in gas-fired sources that are properly tuned originates from the dust in the inlet air and metal erosion within the sources (e.g., tubes, combustion surfaces, etc.). Sources that are not properly tuned may also produce filterable particulate matter as a result of incomplete combustion of fuel hydrocarbons that agglomerate to form soot particles. These particles pass through the firebox and are emitted in the exhaust gas. Condensable particulate matter can result from oxidation of fuel sulfur (to sulfur trioxide) and from incomplete combustion of hydrocarbons in the fuel. For the purposes of this BACT analysis, all of the particulate matter emitted from the proposed process heaters is assumed to be PM<sub>10</sub> and PM<sub>2.5</sub>.

Control options available include:

- Proper equipment design and operation (good combustion control)
- Fuel specification
- Post-combustion controls (baghouse and electrostatic precipitator)

Each of these control options is discussed further below.

Good Combustion Control. Implementation of proper combustor design and operation to achieve good combustion efficiency in heaters and boilers will minimize the generation of CO, VOC, and filterable particulate matter. Good combustion efficiency relies on both hardware design and operating procedures. A firebox design that provides proper residence time, temperature, and combustion zone turbulence in combination with proper control of the air-to-fuel ratio, are essential elements of good combustion control.

Gaseous Fuel Specifications. A common form of particulate matter control from combustion sources is the requirement to use a specified gaseous fuel, such as natural gas. Whereas a solid fuel, such as coal, produces a larger amount of particulate matter, gaseous fuels are considered “clean” with respect to generation of particulate matter emissions. Gaseous fuels have differing specifications, depending on their source. Natural gas is processed to meet certain specifications such that the key combustion parameters (e.g., percent methane, heating value, and sulfur content) are relatively consistent in most parts of the country. PM emissions from properly designed and controlled natural gas-fired equipment are generally considered the lowest achievable.

Refinery fuel gas is a byproduct of refining operations that is typically processed and consumed on-site. As a result, it is not possible to meet pipeline natural gas composition specifications. With proper burner design and operation, refinery fuel gas-fired sources can achieve PM/PM<sub>10</sub> emission levels that approach those of natural gas. Combustion of

refinery fuel gas will result in slightly higher PM/PM<sub>10</sub> emissions than combustion with natural gas because of the higher molecular weight hydrocarbons (propane and butane) and the presence of sulfur compounds. The presence of higher molecular weight hydrocarbons in refinery fuel gas makes it more difficult to properly tune the burner to minimize the formation of particulates. The higher level of sulfur compounds in refinery fuel gas results in production of more SO<sub>3</sub>, a compound that contributes to condensable particulate matter emissions. As previously noted, the H-1001 Reformer Heater is expected, on average during normal operations, to get approximately 70% of the BTUs required from PSA tailgas that is considered to be a sulfur-free fuel. Natural gas or refinery fuel gas will provide the remaining fuel during normal operation and will be used exclusively during unit startup. As such, for this heater it is expected that PM/PM<sub>10</sub> emissions will be nearly equivalent to emissions expected from firing 100% natural gas.

Baghouse. A baghouse removes particulate from an exhaust stream by passing the gas through a fabric filter bags that are periodically cleaned using any of a number of techniques such as high-pressure reverse flow air pulses, high intensity sonic horns and shaking. A baghouse is generally capable of achieving the lowest particulate emission rates of any type of add-on particulate control device.

Electrostatic Precipitator. An electrostatic precipitator (ESP) uses electrodes to collect particulate by imparting a static electric charge on the particles as they pass through the high intensity electric field called a corona that forms around the corona wire. The particles are then attracted to and collect on electrically charged plates. These plates are periodically “rapped” by solenoid-activated weights that rap on the top end of the plates to dislodge the collected particles. The material then falls by gravity into hoppers below the ESP and is removed for disposal. The ability of an ESP to remove particulate matter depends in large part on the electrical properties of the particle itself and the sulfur content of the particle directly impacts those properties. Inorganic particles that are higher in sulfur content are more electrically conductive and are very readily collected by an ESP. In contrast, soot particles formed by condensation after partial combustion of gaseous fuel, have relatively lower sulfur content and are essentially non-conductive. Electrostatic collectors do not readily capture these particles.

The size of the particulate is also of great concern since very small soot particles are influenced almost equally by impacts with gaseous molecules or electrostatic forces, and will be less efficiently captured. Capture is more efficient with larger particles. Although ESPs can also achieve very low particulate emission rates, the achievable emission rates from an ESP are higher than the particulate concentration expected from the combustion of gaseous fuels. As such, ESPs are not used for particulate control for combustion devices burning natural/refinery gas.

The use of baghouses and ESPs for post-combustion controls is common on residual oil and coal-fired combustion units that require significant particulate matter reduction, and which typically have much higher particulate loading, solid particle sulfur content, and larger sized particles. Baghouses and ESPs have not been used for particulate control for combustion devices burning gaseous fuels such as natural gas or refinery fuel gas.

Although baghouses and ESPs are both theoretically feasible for application to gas-fired process heaters, fabric filters and ESPs are not considered technically feasible for the control of the PM/PM<sub>10</sub> emissions from gas-fired heaters. These controls would not be expected to provide any significant emissions reductions because of the already low particulate matter emission rate and the fine particle size of the emissions from these units. The fact that such controls have not been applied to similar sources is a clear indication of their technical infeasibility. Additional technical support for this conclusion is outlined below.

Fabric filters rely on the build-up of a filter cake to act as a filtering medium for collection of particulate matter. Periodically, this filter cake is removed, and filtration efficiency declines until a filtering cake can be re-established. The ultra-fine size of particulate emissions from firing of gaseous fuels is such that no cake could be established in a fabric filter. Instead, the very fine particles would be expected to either pass through the bags uncontrolled, or they would “blind” filter bags fairly quickly, resulting in unacceptable pressure drops and requiring impossibly frequent bag replacement.

ESPs rely on the ability of a particle to acquire an electrical charge. Once charged, the particles migrate from the flue gas to oppositely charged plates where they deposit. The deposits are removed by “rapping” the plates and they settle by gravity to collection hoppers. The organic nature of the ultra-fine particulates generated by gaseous fuel combustion is such that acquiring the necessary electrical charge is difficult. ESPs also rely on gravity settling of the collected particulates. The fine particles produced in gas-fired heaters are such that gravity settling is unlikely to occur and any particles collected on the plates would likely be re-entrained in the flue gas as the plates are rapped.

The top-performing feasible PM/PM<sub>10</sub> control technology is the firing of purchased natural gas in this heater because the very low sulfur content of natural gas will result in low condensable PM<sub>10</sub> and PM<sub>2.5</sub> emissions relative to the use of typical RFG. As previously stated, the majority of fuel to be fired in the H-1001 Reformer Heater will be PSA tailgas which, due to its composition, will result in PM<sub>10</sub> and PM<sub>2.5</sub> emission rates similar to those expected from firing 100% natural gas. The next most effective technically feasible PM control option is the use of good combustion practices in combination with firing gaseous fuels.

For H-1001, the calculated cost of firing purchased natural gas in place of RFG is greater than \$38 million/ton of PM<sub>10</sub> or PM<sub>2.5</sub> reduced, based on a natural gas price of approximately \$5/MMBtu.<sup>13</sup> As such, this option is not considered cost effective for the heater, and is rejected as BACT.

CHS reviewed all PM/PM<sub>10</sub> BACT determinations for RFG-fired sources found in the RBLC and as a result requested that proper design and good combustion techniques constitute BACT. In summary, the Department determined that CO, VOC and PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions shall be controlled by proper design and good combustion practices.

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<sup>13</sup> CHS calculated the cost effectiveness by assuming that 3.6% of the fuel-bound sulfur would be measured as condensable PM<sub>10</sub> or PM<sub>2.5</sub>. According to EPA’s AP-42, Table 1.3-1 (7/98), approximately 3.6% of the sulfur in the fuel converts to SO<sub>3</sub> during combustion, which becomes condensable particulate matter that is measured as H<sub>2</sub>SO<sub>4</sub> when analyzed.

## C. **Truck Loading Rack System**

The truck loading rack system project entails construction of a new gasoline and distillate truck loading operation and nine new support tanks. A portion of the existing tankage may (Tanks 135) be utilized in support of the new truck loading facility. Additionally, the project includes construction of a propane storage and truck loading area. Without any limits, the potential to emit of the proposed truck loading system would be based on the maximum loading rate of 7,200 gallons per minute for the rack and VCU. However, based on the physical properties of the system, the product loading volumes would be in excess of the refinery capacity and would show a PTE for VOC's that would be unattainable. Additionally, the proposed project would be considered a major modification. To avoid this, CHS reviewed historical gasoline and distillate truck loading throughput from the existing system and the market for these products loaded to trucks to help determine a basis for potential emissions.

CHS has estimated that three times the historical gasoline and diesel truck loading volumes would allow maximum flexibility in potential sales through the new truck rack, while still placing realistic emissions limits (specifically VOCs) on the new system. A limitation based on three times the historical loading volumes can also serve to keep this project from being classified as a major modification to the facility; however, CHS has requested not to be limited to any specific volume of product loaded through the loading rack in order to maintain maximum flexibility of operations.

As a result, CHS requested annual combined total VOC emission limit of 39.23 TPY for the new loading rack and associated equipment. This safety factor (of three times the historical average) will allow the refinery significant flexibility to vary loading volumes and ratios of product types in the future, while maintaining a fixed potential to emit of VOCs. The proposed VOC limit for the new loading rack and storage system also included the previously permitted emissions (MAQP #1821-25) for storage tanks 135 and 136 (12.62 TPY), as well as the fugitive emissions from that project (0.77 tpy). Although CHS requested to remove the existing limit on Tanks 135 and 136, the Department opted to leave the emission limit in the permit until startup of the new loading rack and associated equipment is complete.

### **Truck Loading Rack**

The new truck loading rack is designed to have four bays. Three bays would be available for loading product into trucks and the fourth bay reserved for offloading ethanol and other fuel additives. Each of the three bays will have four loading arms, two for gasoline and two for diesel. VOC emissions are the primary pollutant of concern from product loading activities.

### **VOC BACT Analysis for the Truck Loading Rack**

VOC emissions result from the volatilization of the liquid hydrocarbon product and displacement of generated vapors during tank truck loading operations.

As identified by CHS, capture and subsequent control or destructions is generally the accepted standard for control of VOC's from petroleum product handling and loading. The following VOC control technologies were identified as commercially available and technically feasible for product loading operations:

- Carbon Adsorption
- Incineration (including Thermal and Catalytic Oxidizers)

- Condensation (Refrigerated and Non-refrigerated)
  - Coalescer
- Vapor Combustion Unit

Carbon Adsorption. Carbon adsorption uses activated carbon to remove VOC from low to medium concentration gas streams by adsorption. Adsorption itself is a phenomenon where gas molecules passing through a bed of solid particles (e.g., activated carbon) are selectively held there by attractive forces which are weaker and less specific than those of chemical bonds. During adsorption, a gas molecule migrates from the gas stream to the surface of the solid where it is held by physical attraction releasing energy, which typically equals or exceeds the heat of condensation. Most adsorbents can be cleaned by heating to a sufficiently high temperature, usually using steam or hot combustion gases or by lowering the pressure to a low value (vacuum). This cleaning process creates a waste product that will have to be properly disposed.

Common types of carbon adsorbents used for collecting VOC gas include: fixed regenerable beds, disposable/rechargeable canisters, traveling bed adsorbers, fluid bed adsorbers, and chromatographic baghouses, but fixed bed and canister adsorbents are the most common. VOC and acid gases can be controlled with control efficiencies greater than 90%. Common problems associated with carbon adsorption are plugging and fouling of the activated carbon when exposed to wet or heavily concentrated particulate gas streams.

Incineration. VOCs generated from product loading can be collected and controlled using incineration. Commercially available and technically feasible options include incineration via thermal incinerator or in a catalytic incinerator. In a catalytic incinerator, a catalyst is used to increase the rate of the combustion reaction, allowing the combustion to occur at a lower temperature, typically around 600°F. Thermal incineration is performed at much higher temperatures than catalytic incineration, typically between 1200°F and 2000°F. Control efficiencies for both thermal and catalytic incineration can be designed as high as +99% for noxious gas streams and typically lower for less noxious gas streams (between 95% and 98%). Catalytic incinerators can plug with high particulate loading and can foul with heavy metals, phosphorus, and sulfur compounds.

The major advantage of incineration is that virtually any gaseous organic stream can be incinerated safely and cleanly, provided proper engineering design is employed. Incineration converts organic compounds into carbon dioxide and water; assuming complete combustion. Typically, the waste gas stream is much lower in temperature than that required for incineration; therefore, energy must be supplied to the incinerator to raise the waste gas temperature. Additional supplemental fuel use is required to maintain bed temperatures, during periods when sufficient waste gas is not present to support combustion.

Condensation. Condensers in use today typically employ two techniques: refrigerated or non-refrigerated. Non-refrigerated condensers are widely used as raw material and/or product recovery devices in chemical process industries. Refrigerated condensers are used as air pollution control devices for treating emission streams with high VOC concentrations (e.g., gasoline bulk terminals, storage, etc.).

Condensation is a separation technique in which one or more volatile compounds of a vapor mixture are separated from the remaining vapors through saturation followed by a phase change. The phase change can be achieved by increasing the system pressure at a given temperature, or by lowering the temperature at a constant pressure.

Removal efficiency of a condenser is dependent on the emission stream characteristics including the nature of the VOC in question, VOC concentration, and type of coolant used. Removal efficiencies above 90% can be achieved with coolants such as chilled water, brine solutions, ammonia, special filter media, etc.

Another type of condenser is a coalescer, which uses a filter medium to collect and condense vapor mist containing VOC emissions. Coalescers have been used on asphalt loading and storage facilities for many years and are used in the petroleum refinery industry for collecting and removing VOC emissions from asphalt loading and storage facilities.

Vapor Combustion Unit. Combustion is a control process for VOCs in which the waste gas stream is piped to a remote, usually elevated, location (for safety reasons) and burned in an enclosed stack using a specially designed burner tip, auxiliary fuel, and steam or air to promote mixing for near complete (> 98%) VOC destruction. Complete combustion in a VCU is governed by flame temperature, residence time in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation. As with incineration, the use of VCU for VOC control requires the consumption of supplemental fuel to fire the VCU pilot light and to assist in complete combustion of waste gases. Comparatively, supplemental fuel consumption is significantly less than that of incineration equipment.

As all of the control options proposed were determined to be technically feasible, consideration was given to the pollutant control efficiency and cost effectiveness. As detailed in the *EPA-OAQPS Air Pollution Control Cost Manual*<sup>14</sup> and vendor information, thermal destruction presents the highest control efficiency at  $\geq 98\%$ . Of the two thermal destruction control techniques, CHS proposed the use of a VCU as BACT in the control of VOCs from the product loading facility. Because CHS proposes a control strategy with the highest efficiency, no further analysis is necessary. This device has the highest control efficiency of the options analyzed.

CHS proposes to use a vapor combustion unit to control emissions to a maximum of 10 milligrams of VOC per liter of gasoline loaded (mg/L) from the truck loading rack as BACT. This limit is consistent with 40 CFR 63, Subpart R. Therefore, the Department determined that installation and operation of a VCU that controls VOC emissions to a maximum emission rate of 10 mg/L from the truck loading rack constitutes BACT.

### **CO and NO<sub>x</sub> BACT Analysis for Truck Loading Rack**

As discussed above employing thermal destruction to control VOC's emissions generated from truck loading, via the VCU, will generate pollutants in the form of combustion by-products, namely NO<sub>x</sub> and CO. CHS is currently permitted to operate a VCU from the existing truck loading rack. BACT for the existing VCU were established at 10 mg /L of gasoline loaded for CO, and 4 mg/L of gasoline loaded for NO<sub>x</sub>. Because these limits are consistent with other recently permitted sources operating VCU technology; the Department determined the following CO and NO<sub>x</sub> limits constitute BACT for the truck loading rack:

- Total CO emissions to the atmosphere from the VCU due to loading liquid product shall not exceed 10.0 mg/L of gasoline loaded.

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<sup>14</sup> U.S. EPA Office of Air Quality Planning and Standards, Air pollution Control Cost Manual, January 2002 (EPA/452/B-02-001)

- Total NOx emissions to the atmosphere from the VCU due to loading liquid shall not exceed 4.0 mg/L of gasoline loaded.

### **Bulk Product Storage**

The proposed truck loading rack project also includes nine new storage tanks. Currently, gasoline and diesel fuel are produced at the refinery and stored in various tanks before being loaded in trucks for offsite shipping. In addition to the products produced at the refinery, ethanol and several other additives are offloaded upon delivery into tanks to be blended with the refinery products as they are loaded into trucks.

VOC emissions result from tank working and breathing losses. Working loss occurs when vapor is displaced during tank loading operations and when air drawn into the tank during unloading operations becomes saturated with vapor and expands. Breathing loss is the expulsion of vapor from the tank due to vapor expansion resulting from diurnal temperature and barometric pressure changes.

A VOC BACT analysis was completed for the VOC emissions from the two gasoline tanks, two ethanol tanks and one diesel tank, based on the individual vapor pressure of these products and the corresponding potential to emit (VOCs). CHS did not complete a BACT analysis for the additive tanks due to the low vapor pressure of these products, with uncontrolled VOC emissions being less than 0.25 tons per year for each tank.

The uncontrolled VOC emissions from the bulk storage tanks evaluated within this analysis were calculated using vertical fixed roof tanks without control devices employing the EPA's Office of Air Quality Planning and Standards (OAQPS) - Emission Factor & Inventory Group Tanks software program version 4.0.9d.

### **VOC BACT Analysis for Bulk Gasoline Storage**

All of the control options evaluated in this BACT analysis are deemed technically feasible for gasoline storage. CHS analysis included the following listed VOC control options for this BACT analysis for bulk gasoline storage:

- Returning Vapors to Process
- Carbon Adsorption;
- Vapor Recovery Unit (VRU)/Condensation;
- VCU (smokeless combustion device); and
- Internal Floating Roof (IFR) Tank.

Returning Vapors to Process. Returning vapors, resulting from working and breathing losses, involve the routing of vapors to a process or fuel gas system via hard piping, such that the tank releases no emissions to the atmosphere. The complex network of piping and pump system required for a vapor return system provides a cost per ton of VOC reduction of \$9,269. While this control options demonstrates the highest control efficiency, CHS determined that a vapor return system is not economically feasible and rejected this as BACT.

Carbon Adsorption. Carbon adsorption uses activated carbon to remove VOCs from low to medium concentration gas streams by adsorption. Adsorption itself is a phenomenon where gas molecules passing through a bed of solid particles (e.g., activated carbon) are selectively held by attractive forces which are weaker and less specific than those of chemical bonds. During adsorption, a gas molecule migrates from the gas stream to the

surface of the solid where it is held by physical attraction, releasing energy which typically equals or exceeds the heat of condensation. Most adsorbents can be cleaned by heating to a sufficiently high temperature, usually using steam or hot combustion gases or by lowering the pressure to a low value (vacuum). This cleaning process creates a waste product, which will have to be properly disposed.

Five types of adsorbents are used in collecting gases: fixed regenerable beds, disposable/rechargeable canisters, traveling bed adsorbers, fluid bed adsorbers, and chromatographic baghouses. Fixed bed and canister adsorbents are the most common. VOC and acid gases can be controlled with control efficiencies greater than 90%. Common problems associated with carbon adsorption can be plugging and fouling of the activated carbon when exposed to wet or heavily concentrated particulate gas streams.

40 CFR 60, Subpart Kb requires a floating roof tank for gasoline storage. Any control device with a control efficiency less than that of a floating roof would not constitute BACT; therefore, installation and operation of a carbon adsorption system was eliminated from consideration as BACT.

Vapor Recovery Unit. Vapors from the tanks can be routed to a dedicated condensing device which cools the vapor stream and causes the water vapor and most of the aromatic hydrocarbons to condense. Condensation is a separation technique in which one or more volatile compounds of a vapor mixture are separated from the remaining vapors through saturation followed by a phase change. The phase change can be achieved by increasing the system pressure at a given temperature, or by lowering the temperature at a constant pressure. The condensate can be returned to the storage tank.

Condensers in use today may fall in two categories: refrigerated or non-refrigerated. Non-refrigerated condensers are widely used as raw material and/or product recovery devices in chemical process industries. Where refrigerated condensers are typically used as air pollution control devices for treating emission streams with high VOC concentrations (e.g., gasoline bulk terminals, storage, etc.).

Removal efficiency of a condenser is dependent on the emission stream characteristics including the nature of the VOC in question, VOC concentration, and type of coolant used. Removal efficiencies above 90% can be achieved with coolants such as chilled water, brine solutions, ammonia, special filter media, etc.

40 CFR 60, Subpart Kb requires a floating roof tank for gasoline storage. A control device with a control efficiency less than that of a floating roof would not constitute BACT. Therefore, installation and operation of a VRU was eliminated from consideration as BACT.

Vapor Combustion Unit (VCU). VCU is a control process for VOCs in which the waste gas stream is piped to a remote, usually elevated, location (for safety reasons) and burned in an enclosed stack using a specially designed burner tip, auxiliary fuel, and steam or air to promote mixing for nearly complete (> 98%) VOC destruction. Complete combustion in a vapor combustor is governed by flame temperature, residence time in the combustion zone, turbulent mixing of the components to complete the oxidation reaction, and available oxygen for free radical formation. Vapors from the product storage tanks could be captured and vented to a vapor combustor. Due to the design of the storage tanks, air is pulled into the tank every time the tank is drawn down. This causes a potentially explosive air/gas mixture within the tanks. Vapor combustor stacks on such tanks are required to have a well-engineered flashback control system to prevent flash of combustion into the tanks.

The use of vapor combustors involves potential environmental impacts as the unit also produces NO<sub>x</sub>, CO, and SO<sub>2</sub> emissions as combustion by-products. However, these environmental impacts are not considered significant enough to eliminate from further evaluation. The use of a vapor combustor requires the combustion of additional energy to attain the proper temperature range and to supplement fuel load when insufficient volumes of waste gas are available. Again, these energy impacts were not considered significant enough to eliminate this option from further evaluation. Ultimately, CHS determined that the use of an add-on VCU in conjunction with a fixed roof tank was not BACT and was removed from consideration because the control efficiency is less than that of a stand-alone internal floating roof (IFR) tank.

Internal Floating Roof Tank with Vapor Combustion Unit. This design incorporates a fixed roof with an additional internal roof structure that floats on the surface of the stored liquid. The internal floating roof includes mechanical shoe primary seals and shoe-mounted secondary seals along the edge of the roof to effectively eliminate evaporative losses. As further control, the headspace between the floating roof and the fixed roof is vented to an add-on VCU for additional control. The calculated dollars per ton cost-effectiveness of an internal floating roof with add-on VCU as compared to a stand-alone IFR tank without control are similar. However, the incremental cost to achieve the addition measure of control, using IFR Tank alone as the baseline of control, makes the establishment of IFR Tank with VCU as BACT economically infeasible and therefore is rejected.

Internal Floating Roof Tank. As discussed above an IFR Tank consists of a fixed roof tank with an internal floating roof structure fitted with primary and secondary seals. CHS proposed the IFR tank option as BACT for VOC control from the bulk storage of gasoline as this control technology is shown to be technically feasible, without significant environmental, energy, or economic impacts.

The table below presents the cost effectiveness of the various control technologies proposed in CHS's VOC BACT analysis for gasoline storage.

**Results of Bulk Gasoline Storage VOC Control Cost Analysis**

Control Alternative	VOC Emissions (TPY)	VOC Emissions Reduction (TPY)	Total Annualized Cost (\$10 <sup>6</sup> /yr)	Average Cost Effectiveness (\$/ton VOC controlled) <sup>a</sup>	Incremental Cost-Effectiveness (\$10 <sup>6</sup> /ton) <sup>b</sup>	Additional VOC Emissions Controlled (tons/year) <sup>c</sup>
Return Vapors	~ 0	~ 185.3	1.72	\$ 9,269	1.10	1.45
IFR Tank w/ VCU <sup>d</sup>	0.1853	185.11	0.26	\$ 1,396	0.10	1.42
IFR Tank <sup>d</sup>	1.48	183.82	0.12	\$ 628	--	--

<sup>a</sup> Cost-effectiveness (\$/ton) = [(Total Capital Investment x Capital Recovery Factor) + Direct Annual Cost + Indirect Annual Cost]/(tons VOC Controlled)

*Capital recovery factor based on 10 year control system life and 7% interest*

<sup>b</sup> Incremental cost-effectiveness employs IFR Tank technology as the baseline control efficiency (99.2%)

<sup>c</sup> Additional VOC emissions controlled above the baseline control offered by the use of an IFR Tank

<sup>d</sup> Incremental cost of an internal floating roof system over a fixed roof system.

This option is consistent with other recently permitted similar sources and meets the requirements established with 40 CFR 60, Subpart Kb. Therefore, the Department determined that the application of a stand-alone IFR Tank for the control of VOC emissions from bulk gasoline storage constitutes BACT.

**VOC BACT Analysis for Ethanol Storage**

All of the control options evaluated in this BACT analysis are deemed technically feasible for ethanol storage. CHS analysis included the following listed VOC control options for this BACT analysis for bulk ethanol storage:

- Returning Vapors to Process
- Carbon Adsorption;
- Vapor Recovery Unit (VRU)/Condensation;
- VCU (smokeless combustion device);
- Internal Floating Roof (IFR) Tank.

Control technology options considered for VOC control within the BACT Analysis for ethanol storage were identical to those evaluated above within the BACT analysis for gasoline storage. The only substantive deference within the analyses is the effective control efficiencies as a result of the varied vapor pressure characteristic exhibited by gasoline and ethanol.

CHS’s VOC BACT analysis was conducted using information in the *OAQPS Manual* and engineering data from CHS. The tables below summarizes the uncontrolled VOC emissions from the bulk storage tanks for ethanol and the cost effectiveness for the VOC control options listed above.

**Uncontrolled VOC Emissions for Ethanol Tanks**

<b>Emitting Unit</b>	<b>Uncontrolled Emissions (tpy)</b>
Ethanol Storage Tanks (Each)	1.85

Note: The uncontrolled VOC emissions from the bulk storage tanks for ethanol were calculated using vertical fixed roof tanks without control devices in EPA’s recommended Tanks 4.09d program.

### Cost-Effectiveness of VOC Control Options for Ethanol Tanks

Control Alternative	VOC Emissions (TPY)	VOC Emissions Controlled (TPY)	Total Annualized Cost (\$10 <sup>6</sup> /yr)	Average Cost Effectiveness (\$/ton VOC controlled) <sup>a</sup>	Additional VOC Emissions Controlled (tons/year) <sup>b</sup>
Return Vapors	~ 0	~ 1.85	1.717	\$ 928,450	0.10
IFR Tank w/ VCU <sup>c</sup>	1.85E-03	1.848	0.259	\$ 139,968	0.10
FR Tank w/ VCU <sup>d</sup>	3.70E-02	1.813	0.116	\$ 78,950	0.07
Carbon Adsorption	9.25E-02	1.758	0.068	38,467	7.4E-03
IFR Tank	9.99E-02	1.750	--	--	--

<sup>a</sup> Cost-effectiveness (\$/ton) = [(Total Capital Investment x Capital Recovery Factor) + Direct Annual Cost + Indirect Annual Cost]/(tons VOC Controlled)

*Capital recovery factor based on 10 year control system life and 7% interest*

<sup>b</sup> Additional VOC emissions controlled above the baseline control offered by the use of an IFR Tank.

<sup>c</sup> Incremental cost of an internal floating roof system over a fixed roof system.

<sup>d</sup> Cost include capital investment and annual cost of VCU only

Returning Vapors to Process. Returning vapors resulting from working and breathing losses involve the routing vapors to a process or fuel gas system via hard piping, such that the tank effectively has no emissions to the atmosphere. The cost per ton of VOC reduction presented for a vapor return system is determined to be not economically feasible and is therefore reject as BACT.

Carbon Adsorption. Carbon adsorption using activated carbon for removal of VOC gas resulting from tank breathing and working losses is rejected as BACT due to economic infeasibility.

Vapor Recovery Unit. A VRU for condensation and collection of vapor stream waste gases is eliminated from consideration as BACT, due to the failure of this control option to meet the control effectiveness of a floating roof tank. As floating roof tanks are required for ethanol storage within 40 CFR 60, Subpart Kb, the control efficiency presented by a floating roof is the established baseline.

Vapor Combustion Unit (VCU). While the use of an add-on VCU in conjunction with a fixed roof storage tank does present a higher control efficiency than that of a stand-alone IFR tank for the storage of ethanol, the annualized cost-effectiveness of this control technology renders it economically infeasible. Therefore, CHS has eliminated use of a VCU from consideration.

Internal Floating Roof Tank with Vapor Combustion Unit. Utilization of an IFR tank with an add-on VCU was eliminated from consideration as BACT for the control of VOC emissions from ethanol storage, due to the economic infeasibility of this option.

Internal Floating Roof Tank. CHS has proposed the use of an IFR tank as BACT for VOC control from the bulk storage of ethanol, as this control technology is shown to be technically feasible, without significant environmental, energy, and economic impacts.

This option is consistent with other recently permitted similar sources and meets the requirements established with 40 CFR 60, Subpart Kb, therefore, the Department concurs with the application of a stand-alone IFR Tank as BACT for the control of VOC emissions from bulk ethanol storage.

### **VOC BACT Analysis for Diesel Storage Tanks**

The VOC BACT analysis was conducted using information from Chapter 3 of the *EPA-OAQPS Air Pollution Control Cost Control Manual* and engineering data from CHS. As proposed, the diesel tanks may contain either No. 1 or No. 2 diesel. CHS used the higher vapor pressure for #1 diesel in all emissions estimates and cost calculations within this analysis because #1 diesel gives higher VOC emissions and lower control costs than #2 diesel.

CHS considered the following VOC control options for this BACT analysis for bulk gasoline storage:

- Returning Vapors to Process
- Carbon Adsorption;
- Vapor Recovery Unit (VRU)/Condensation;
- VCU (smokeless combustion device);
- Floating Roof Tank

Descriptions of these control options are the same as for control of VOCs from the aforementioned gasoline and ethanol storage BACT analysis.

CHS believes that all of the listed control technologies are technically feasible for this application, therefore the BACT analysis explored all of the listed VOC control options.

#### **Uncontrolled VOC Emissions for the Diesel Tank**

<b>Emitting Unit</b>	<b>Uncontrolled Emissions (tpy)</b>
Diesel Storage Tank	2.73

The uncontrolled VOC emissions from the bulk storage tank for diesel were calculated using vertical fixed roof tanks without control devices in EPA's recommended Tanks 4.09d program.

The table below presents the cost effectiveness of the various control technologies proposed in CHS's VOC BACT analysis for bulk diesel storage.

### Results of Bulk Diesel Storage VOC Control Cost Analysis

Control Alternative	VOC Emissions (TPY)	VOC Emissions Controlled (TPY)	Total Annualized Cost (\$10 <sup>6</sup> /yr)	Average Cost Effectiveness (\$/ton VOC controlled) <sup>a</sup>
Return Vapors	~ 0	~ 2.73	1.717	\$ 629,169
IFR Tank w/ VCU <sup>c</sup>	2.73E-03	2.72	0.259	94,850
FR Tank w/VCU <sup>d</sup>	5.46E-02	2.68	0.143	53,500
IFR Tank <sup>c</sup>	6.55E-02	2.66	0.116	43,365
Carbon Adsorption	1.37E-01	2.59	0.0676	26,067
VRU	2.73E-01	2.46	0.0645	26,269

<sup>a</sup> Cost-effectiveness (\$/ton) = [(Total Capital Investment x Capital Recovery Factor\*) + Direct Annual Cost + Indirect Annual Cost]/(tons VOC Controlled)

\* Capital recovery factor based on 10 year control system life and 7% interest

<sup>c</sup> Incremental cost of an internal floating roof system over a fixed roof system.

<sup>d</sup> Cost include capital investment and annual cost of VCU only

Based on the information presented above, CHS believes that based on the cost of all evaluated control options for the bulk storage of diesel fuel are excessive. CHS proposes BACT for the diesel tank as a fixed roof storage tank with submerged fill loading. Furthermore, CHS indicated the control option selected, a fixed roof tank, is consistent with other recently permitted similar sources.

For the bulk storage of diesel, the Department determined that a fixed roof tank with submerged fill piping, as well as use of a pressure/vacuum vent constitutes BACT for the control of VOC emissions. This determination is consistent with other recently permitted similar sources.

#### **VOC BACT for Fugitive Leaks**

VOC emissions resulting from addition of piping components is expected to be no more than 0.38 tons per year. This low emission rate and the technical challenge of capturing emissions from a large number of minute sources dispersed over a large area make add-on controls technically and economically infeasible. Emissions from these sources will be minimized by following a prescribed program of leak inspection, recordkeeping, and repair. In recent permitting actions, including most recently the application for MAQP #1821-26, CHS conducted a VOC BACT analysis for equipment leaks and concluded that an effective LDAR program meeting the requirements of NSPS Subpart GGGa constitutes BACT.

Following the BACT decisions in previous permit actions and BACT determinations for similar sources, the Department determined that an effective monitoring and maintenance program or leak detection and repair (LDAR) program (as prescribed under 40 CFR 60 Subpart VVa) meeting the requirements of 40 CFR 60, Subpart GGGa constitutes VOC BACT for equipment leaks from the new components.

**PM<sub>10</sub> BACT for Fugitive Truck Traffic**

Due to the small amount of particulate emissions generated by fugitive truck traffic (approximately 5 tons per year PM<sub>10</sub>), CHS has not prepared a BACT analysis for this emitting source. CHS proposes the construction of paved roadways and parking lots, along with reasonable precautions to prevent airborne particulate emissions as BACT for fugitive emissions from truck traffic. The Department agrees that paved roadways and parking lots, along with reasonable precautions constitute BACT.

IV. Emission Inventory

The following tables summarize the potential to emit for the proposed projects associated with this permit action. Table 1 summarizes emissions increases associated with the Mild Hydrocracker Project (based on maximum diesel production). Many of these units were previously approved in other permit actions, this permit action mainly addresses the new FCC Charge Heater, and a new Riser and Riser design that changes the FCCU Reactor/Regenerator from being a project “affected” emitting unit to a “modified” emitting unit. and the FCCU Regenerator. Table 2 summarizes emissions increases associated with the Mild Hydrocracker Project (based on maximum gasoline production). Table 3 summarizes emissions increases associated with the Benzene Reduction Unit. Table 4 summarizes emissions increases associated with the Truck loading Project. Detailed calculations are on file with the Department as well as emissions inventories from previous permit actions.

<b>Table 1 Summary of Project Related Emissions Increases (TPY) for Mild Hydrocracker Project - Maximum Diesel Production Case (Updated for Final Design)</b>						
	NOx	SO <sub>2</sub>	TSP	PM-10/2.5	CO	VOC
<b>New Units</b>						
H-102 Reformer Heater	11.3	0.5	2.8	2.8	25.1	0.3
FCCU Charge Heater	10.1	2.3	2.2	2.2	19.2	1.6
<b>Modified Units</b>						
Zone D SRU/TGTU (process)		9.1				
Zone D SRU Incinerator (fuel)	1.4	0.0	0.1	0.1	1.4	0.1
Fugitive emission components						10.0
FCCU Regenerator	0.0	0.0	0.0	0.0	35.1	0.0
<b>Affected Units</b>						
Reformer H-101	2.9	0.0	0.0	0.0	3.6	0.1
H-201 Reactor Charge Heater	0.3	0.0	0.1	0.1	0.0	0.0
H-202 Fractionator Feed Heater	0.3	0.0	0.1	0.1	0.0	0.0
FCCU Regenerator	0.0	0.0	0.0	0.0	18.4	0.0
NHT Charge Heater	0.4	0.0	0.0	0.0	0.1	0.0
NHT Stripper Reboiler #1	0.6	0.0	0.0	0.0	0.5	0.0
NHT Stripper Reboiler #2	0.6	0.0	0.0	0.0	0.5	0.0
NHT Splitter Heater	0.4	0.0	0.0	0.0	0.3	0.0

<b>Table 1</b>						
<b>Summary of Project Related Emissions Increases (TPY) for Mild Hydrocracker Project - Maximum Diesel Production Case (Updated for Final Design)</b>						
	NOx	SO <sub>2</sub>	TSP	PM-10/2.5	CO	VOC
Platformer Heater	9.6	0.1	0.3	0.3	2.9	0.2
Platformer Debutanizer Heater	0.5	0.0	0.0	0.0	0.5	0.0
Platformer Splitter Reboiler	0.0	0.0	0.0	0.0	0.0	0.0
Storage Tanks						16.3
Loading VCU	0.3	0.0	0.0	0.0	0.4	0.7
Loading Fugitives						0.3
#5 Cooling Tower			0.1	0.1		0.1
<b>Project Affected Emissions Units, Totals</b>	<b>38.7</b>	<b>12.1</b>	<b>5.8</b>	<b>5.8</b>	<b>89.6</b>	<b>29.7</b>
PSD Thresholds	40	40	25	15 / 10	100	40
PSD Review Required?	NO	NO	NO	NO	NO	NO

Note: The rows highlighted in grey are the changes that were made under this permit action.

<b>Table 2</b>						
<b>Summary of Project Related Emissions Increases (TPY) for Mild Hydrocracker Project - Maximum Gasoline Production Case (Updated for Final Design)</b>						
	NOx	SO <sub>2</sub>	TSP	PM-10/2.5	CO	VOC
<b>New Units</b>						
H-102 Reformer Heater	11.3	0.5	2.8	2.8	25.1	0.3
FCCU Charge Heater	10.1	2.3	2.2	2.2	19.2	1.6
<b>Modified Units</b>						
Zone D SRU/TGTU (process)		9.1				
Zone D SRU Incinerator (fuel)	1.4	0.0	0.1	0.1	1.4	0.1
Fugitive emission components						10.0
FCCU Regenerator	0.0	0.0	0.0	0.0	35.1	0.8
<b>Affected Units</b>						
Reformer H-101	2.9	0.0	0.0	0.0	3.6	0.1
H-201 Reactor Charge Heater	0.3	0.0	0.1	0.1	0.0	0.0
H-202 Fractionator Feed Heater	0.3	0.0	0.1	0.1	0.0	0.0
FCCU Regenerator	0.0	0.0	0.0	0.0	18.4	0.8
NHT Charge Heater	0.1	0.0	0.0	0.0	0.0	0.0
NHT Stripper Reboiler #1	0.1	0.0	0.0	0.0	0.1	0.0
NHT Stripper Reboiler #2	0.1	0.0	0.0	0.0	0.1	0.0
NHT Splitter Heater	0.1	0.0	0.0	0.0	0.1	0.0
Platformer Heater	2.1	0.0	0.1	0.1	0.6	0.0
Platformer Debutanizer Heater	0.1	0.0	0.0	0.0	0.1	0.0
Platformer Splitter Reboiler	0.0	0.0	0.0	0.0	0.0	0.0
Alkylation Hot Oil Heater	0.4	0.0	0.1	0.1	0.5	0.1
Storage Tanks						17.3
Loading VCU	0.3	0.0	0.0	0.0	0.4	0.7
Loading Fugitives						0.4
#5 Cooling Tower			0.1	0.1		0.1

<b>Table 2</b> <b>Summary of Project Related Emissions Increases (TPY) for</b> <b>Mild Hydrocracker Project - Maximum Gasoline Production Case</b> <b>(Updated for Final Design)</b>						
	NOx	SO <sub>2</sub>	TSP	PM-10/2.5	CO	VOC
<b>Project Affected Emissions Units, Totals</b>	<b>29.6</b>	<b>12.0</b>	<b>5.6</b>	<b>5.6</b>	<b>86.4</b>	<b>31.4</b>
PSD Thresholds	40	40	25	15 / 10	100	40
PSD Review Required?	NO	NO	NO	NO	NO	NO

Note: The rows highlighted in grey are the changes that were made under this permit action.

<b>Table 3</b> <b>Summary of Project Related Emissions Increases (TPY) for</b> <b>Benzene Reduction Project</b> <b>(Updated for H-1001 Reformer Heater Modification)</b>					
	NOx	SO <sub>2</sub> <sup>a</sup>	TSP/PM <sub>10/2.5</sub>	CO	VOC
<b>New Units</b>					
Platformer Splitter Reboiler (P-HTR-3)	7.0	3.2	0.9	13.6	0.6
Benzene Reduction Unit Fugitives					23.8
Benzene Reduction Unit WW Drains					2.5
<b>Modified Units</b>					
<b>H-1001 Reformer Heater</b>	<b>6.8</b>	<b>2.5</b>	<b>4.3</b>	<b>16.0</b>	<b>1.8</b>
<b>Affected Units</b>					
Boilers 11 and/or 12	3.5	1.5	0.9	7.0	0.9
Platformer Heater (P-HTR-1)	0.1	0.1	0.0	0.2	0.0
Storage Tanks					0.1
Loading Fugitives					0.2
Loading VCU	1.5	0.0	0.1	1.2	0.1
Wastewater Treatment Plant					0.5
<b>Project Affected Emissions Units, Totals</b>	<b>18.9</b>	<b>5.2</b>	<b>6.6</b>	<b>38.1</b>	<b>30.4</b>
<b>PSD/NSSR Thresholds</b>	<b>40</b>	<b>40</b>	<b>25/15/10</b>	<b>100</b>	<b>40</b>
<b>PSD/NSSR Review Required?</b>	<b>NO</b>	<b>NO</b>	<b>NO</b>	<b>NO</b>	<b>NO</b>

Note: The rows highlighted in grey are the changes that were made under this permit action.

<b>Table 4</b> <b>Truck Loading Rack Project (Emissions in TPY)</b>								
Source	VOC	NOx	CO	SO <sub>2</sub>	PM <sub>10</sub>	PM <sub>2.5</sub>	CO <sub>2e</sub>	HAPs
Gasoline/Diesel Loading Rack VCU Emissions	11.46	4.63	11.50	0	0.14	0.14	915.36	0.50
Gasoline/Diesel Loading Rack Vapor Capture Losses	2.30	0	0	0	0	0	0	0.27
New Storage Tank Emissions (Regular In-service and Landing Conditions)	11.32	0	0	0	0	0	0	0.55
Fugitive Emissions from Propane Loading	0.38	0	0	0	0	0	0	0
Fugitive Emissions from Equipment Leaks (including Propane Loading System)	0.38	0	0	0	0	0	0	0.01

Fugitive Dust Emissions from Vehicle Travel	0.00	0	0	0	5.37	1.32	0	0
Storage Tank Emissions from Tanks 135 + 136 (Regular In-service and Landing Conditions)	12.62	0	0	0	0	0	0	-
Fugitive Emissions from Equipment Leaks (Tanks 135 + 136 components)	0.77	0	0	0	0	0	0	0
<b>TOTAL =</b>	<b>39.23*</b>	<b>4.63</b>	<b>11.50</b>	<b>0.00</b>	<b>5.51</b>	<b>1.46</b>	<b>915.36</b>	<b>1.34</b>

\*Note: CHS requested a federally enforceable total annual limit of 39.23 tons of VOC from all of the above equipment to remain under the PSD significance threshold. This is based on the emissions calculated from the loading of three times the recent historical average truck loading volumes.

## V. Existing Air Quality

There are two areas in Billings (approximately 12 miles northeast of the CHS Refinery) which were federally designated nonattainment for CO (NAAQS) and for the old secondary total suspended particulates (PM) standard. EPA redesignated the Billings CO nonattainment area to attainment on April 22, 2002. The old PM standard has since been revoked and replaced with new PM<sub>10</sub> (respirable) standards. The Billings area is listed as not classified/attainment for the new PM<sub>10</sub> standard.

The area (2.0 km) around the CHS Refinery in Laurel is federally designated as nonattainment for the SO<sub>2</sub> NAAQS (40 CFR 81.327). Ambient air quality monitoring data for SO<sub>2</sub> from 1981 through 1992 recorded SO<sub>2</sub> levels in the Laurel and Billings areas in excess of the Montana Ambient Air Quality Standards (MAAQS) for the 24-hour and annual averages. In 1993, EPA determined that the SO<sub>2</sub> SIP for the Billings/Laurel area was inadequate and needed to be revised. The Department, in cooperation with the Billings/Laurel area SO<sub>2</sub> emitting industries, adopted a new control plan to reduce SO<sub>2</sub> emissions by establishing emission limits and requiring continuous emission monitors on most stacks. In addition, on April 21, 2008, the EPA issued a federal implementation plan (FIP) for those SIP provisions it deemed inadequate. The FIP includes additional flare requirements for specified sources. Area SO<sub>2</sub> emissions have since declined between 1992 and 2008. The decline can be attributed to industrial controls added as part of the SIP/FIP requirements, plants operating at less than full capacity, and industrial process changes to meet sulfur in fuel regulations. Ambient air quality monitoring for SO<sub>2</sub>, PM<sub>10</sub>, and CO in the Billings/Laurel area continues.

## VI. Air Quality Impacts

The requirements of ARM 17.8.749 include conditions for issuance or denial of a Montana air quality permit. Specifically, a permit may not be issued for a new or modified facility or emitting unit unless the applicant demonstrates it will not cause or contribute to a violation of a Montana or national ambient air quality standard (NAAQS). CHS has updated the analysis included in the original MHC permit application to evaluate the final design and location of the new FCC Charge Heater.

To assess the potential effects of the proposed project on air quality, the emissions of SO<sub>2</sub> and NO<sub>x</sub> associated with the proposed project were evaluated by using an air dispersion modeling analysis. Only the changes (i.e., increases and decreases) in emissions rates that are directly attributable to the proposed project were evaluated. Specifically, the impact from the two new heaters, H-102 and the replacement FCC Charge Heater, were included as increases and the emissions from the two sources to be shutdown, the replaced FCCU Charge Heater and C-201B compressor, were included as decreases. The EPA-approved AERMOD model was used with five years (2007-2011) of surface meteorological data from Billings, MT and upper air data from Great Falls, MT. The AERMET meteorological processor was used to develop the meteorological data along with EPA's AERSURFACE and AERMINUTE pre-processor programs. Regulatory default settings were employed in conjunction with standard model procedures. For purposes of NO<sub>2</sub> modeling, the Plume Volume Molar Ratio Method (PVMRM)

and the default equilibrium ratio of 0.90 and default NO<sub>2</sub>/NO<sub>x</sub> in-stack ratio of 0.50 were used. The highest hourly background ozone concentration from all monitors in Montana of 63 ppb (Helena - Sieben Flats for 2011) was also used. The PSDCREDIT option in AERMOD was invoked to allow for the proper treatment of the shutdown sources under PVMRM. As shown in the table below, the modeled impacts associated with the proposed project are below the pollutant specific significant impact levels. Thus, it can be concluded that the project will not cause or contribute to an exceedance of the standards.

<b>CHS Five Year AERMOD Summary for MHC Project</b>				
<b>Pollutant</b>	<b>Average</b>	<b>Conc. (ug/m<sup>3</sup>)</b>	<b>SIL (ug/m<sup>3</sup>)<sup>a</sup></b>	<b>% SIL</b>
<b>NO<sub>x</sub></b>	1-hr	7.4	7.5	98%
	Annual	0.005	1.0	0.5%
<b>SO<sub>2</sub></b>	1-hr	6.2	7.8	79%
	3-hr	3.3	25.0	13%
	24-hr	0.7	5.0	14%
	Annual	0.03	1.0	3%

<sup>a</sup> Note that the 1-hr NO<sub>2</sub> and SO<sub>2</sub> SILs have not been promulgated. 4% of the NAAQS has been used as an interim SIL pursuant to EPA guidance.

CHS provided information to show that this permit application does not represent, from an air emissions perspective, a major modification to the refinery. For this reason, the requirement at ARM 17.8 Subchapter 11 to complete a visibility impact assessment is not applicable to the MHC project.

To assess the potential effects on air due to modifications proposed to the previously approved Benzene Reduction Unit project quality, the emissions of SO<sub>2</sub> and NO<sub>x</sub> associated with the proposed project were evaluated by using an air dispersion modeling analysis. Only the changes (i.e., increases and decreases) in emissions rates that are directly attributable to the proposed project were evaluated. Specifically, the air quality impacts due to the incremental increase in emissions from the H-1001 Reformer Heater were evaluated. The EPA-approved AERMOD model was used with five years (2007-2011) of surface meteorological data from Billings, MT and upper air data from Great Falls, MT. The AERMET meteorological processor was used to develop the meteorological data along with EPA's AERSURFACE and AERMINUTE pre-processor programs. Regulatory default settings were employed in conjunction with standard model procedures. For purposes of the 1-hour NO<sub>2</sub> modeling, the Ambient Ratio Method (ARM) and the default ambient NO<sub>2</sub>/NO<sub>x</sub> ratio of 0.80 was used. As shown in the table below, the modeled impacts associated with the proposed project are below the pollutant specific significant impact levels. Thus, it can be concluded that the project will not cause or contribute to an exceedance of the National Ambient Air Quality standards.

<b>CHS Five Year AERMOD Summary for H-1001 Modification</b>				
<b>Pollutant</b>	<b>Average</b>	<b>Conc. (ug/m<sup>3</sup>)</b>	<b>SIL (ug/m<sup>3</sup>)<sup>a</sup></b>	<b>% SIL</b>
<b>NO<sub>x</sub></b>	1-hr	2.92	7.52	38.8%
	Annual	0.03	1.0	3.2%
<b>SO<sub>2</sub></b>	1-hr	4.6	7.84	58.5%
	3-hr	2.4	25.0	9.5%
	24-hr	0.4	5.0	8.7%
	Annual	0.04	1.0	4.0%

<sup>a</sup> Please note that the 1-hr NO<sub>2</sub> and SO<sub>2</sub> SILs have not been promulgated. 4% of the 1-hour NAAQS for each pollutant has been used as an interim SIL pursuant to EPA guidance.

According to CHS, the Benzene Reduction Unit Project does not represent, from an air emissions perspective, a major modification to the refinery. For this reason, the requirement at ARM 17.8 Subchapter 11 to complete a visibility impact assessment is not applicable.

For the truck loading project, CHS complete a health risk assessment for the project (see Section II.K of the permit analysis). In addition, CHS stated that the emissions from this project are not significant enough to result in the violation of any of the Ambient Air Quality Standards. Also, CHS noted that this project will not result in any additional SO<sub>2</sub> emissions from the refinery and will not affect the ambient SO<sub>2</sub> concentration in the SO<sub>2</sub> non-attainment area.

VII. Ambient Air Impact Analysis

CHS provided information to show that the increase in emissions from this permit action will not cause or contribute to a violation of any ambient air quality standard.

VIII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	X	4. Does the action deprive the owner of all economically viable uses of the property?
	X	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	X	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	X	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	X	7a. Is the impact of government action direct, peculiar, and significant?
	X	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
	X	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

Based on this analysis, the Department determined there are no taking or damaging implications associated with this permit action.

IX. Environmental Assessment

An environmental assessment, required by the Montana Environmental Policy Act, was completed for this project. A copy is attached.

**DEPARTMENT OF ENVIRONMENTAL QUALITY**  
**Permitting and Compliance Division**  
**Air Resources Management Bureau**  
**1520 East Sixth Avenue**  
**P.O. Box 200901, Helena, Montana 59620-0901**  
**(406) 444-3490**

**FINAL ENVIRONMENTAL ASSESSMENT (EA)**

*Issued For:* CHS Inc.  
Laurel Refinery  
P.O. Box 909  
Laurel, MT 59044-0909

*Montana Air Quality Permit (MAQP) Number:* 1821-27

*Preliminary Determination on Permit Issued:* 08/21/2012

*Department Decision Issued:* 10/16/2012

*Permit Final:* 11/01/2012

1. *Legal Description of Site:* South ½, Section 16, Township 2 South, Range 24 East in Yellowstone County.
2. *Description of Project:*

On June 4, 2012, CHS Inc. (CHS) submitted a permit application to the Department of Environmental Quality-Air Resources Management Bureau (Department) to modify MAQP # 1821-26 and Title V Operating Permit (OP) # OP1821-10. The application is for modification to two previously permitted refinery projects, and to construct a new gasoline and diesel truck loading facility as summarized below:

Mild Hydrocracker (MHC) Project Update. This application incorporates the final design and location of the FCC Charge Heater being replaced as part of the MHC Project. The FCC Charge Heater was originally approved at 60 million British thermal units per hour (MMBtu/hr) as part of the MHC project (MAQP #1821-23). This permit application modifies the size of the heater from 60 to 66 MMBtu/hr. In addition, the permit application reclassifies the fluidized catalytic cracking unit (FCCU) Reactor/Regenerator as a “modified” emitting unit rather than an “affected unit,” and CHS requests to replace the existing Riser with a new Riser as the current Riser is nearing the end of its mechanical life.

Benzene Reduction Unit (BRU) Project Update. This project involves modification of the H-1001 Reformer Heater to achieve the design hydrogen production rate within the 1000 Unit Hydrogen Plant. Expansion of the 1000 Unit Hydrogen Plant was included in the MAQP #1821-18. However, the 1000 Unit Hydrogen Plant expansion changed the characteristics of the PSA tailgas (e.g. the heat content (British thermal units per standard cubic feet (Btu/scf) declined and the volume produced increased (standard cubic feet per minute (scfm))). According to CHS, the total heat input associated with the PSA tailgas remained nearly the same. As a result, the existing PSA tailgas burners on the H-1001 Reformer Heater could not handle the increased volume of PSA tailgas without excessive pressure drop and the 1000 Unit Hydrogen Plant production rate became limited by the volume of PSA tailgas that could be combusted. The proposed permit modification is to replace the PSA tailgas burner tips with tips that have larger ports such that all the PSA tailgas that is generated can be combusted in H-1001. CHS is also proposing to replace the supplemental fuel (e.g. natural gas, refinery fuel gas) burners in H-1001 to achieve improved NOx emission performance.

The current heater is physically capable of combusting refinery fuel gas but cannot meet the existing NOx permit limits while doing so. Additionally, the modified heater will have a higher maximum design firing rate (191.8 MMBtu-higher heating value (HHV)/hr post project versus 177.7 MMBtu-HHV/hr) and a slight increase in the actual firing rate is also expected.

Gasoline and Distillate Truck Loading Facilities Project. This permit application also proposes the construction of new gasoline and distillate truck loading facilities, including new storage tanks, loading rack and vapor combustion unit (VCU). The goal of the project is to improve safety and reduce truck congestion at the existing loading facility to be removed from service once the new one is constructed. Additionally, the permit modification adds a new propane storage and loading facility. The existing gasoline and distillate truck loading rack and associated VCU will be removed from service once the rack is constructed.

In addition to those items mentioned above, this permit action also includes miscellaneous updates and amendments. CHS requested to discontinue use of the sulfur dioxide (SO<sub>2</sub>) Continuous Emissions Monitoring System (CEMs) on the H-1001 stack because H-1001 is subject to 40 CFR 60, Subpart Ja which includes exemptions from hydrogen sulfide/sulfur dioxide (H<sub>2</sub>S/SO<sub>2</sub>) monitoring requirements for fuel gas streams that are inherently low in sulfur content. The primary fuel to H-1001, PSA tailgas is inherently low in sulfur content. CHS already monitors the H<sub>2</sub>S content of the refinery fuel gas (RFG) to be combusted in H-1001 as supplemental fuel, which would meet the monitoring requirements of 40 CFR 60, Subpart Ja.

CHS requested that the Department remove condition IV.E.4 which requires the use of statistically significant F-factor values in determining compliance with oxides of nitrogen (NOx) and carbon monoxide (CO) limits for the H-102 Reformer Heater. Rather, CHS proposes that results of the required performance testing be used to calculate an appropriate emission factor to demonstrate ongoing compliance with NOx and CO limits.

3. *Objectives of Project:* The primary purpose of this permitting action would be: 1) to construct a new loading rack, VCU and associated tanks; 2) to redesign and construct a new FCCU riser and FCC Charge heater in addition to other updates on the previously approved mild hydrocracker project; 3) to modify the existing H-1001 Reformer heater by replacing the PSA tailgas burner tips with tips that have larger ports and by replacing the supplemental fuel burners to achieve improved NOx emission performance.
4. *Alternatives Considered:* In addition to the proposed action, the Department also considered the “no-action” alternative. The “no-action” alternative would deny issuance of the MAQP to the proposed facility. However, the Department does not consider the “no-action” alternative to be appropriate because CHS demonstrated compliance with all applicable rules and regulations as required for permit issuance. Therefore, the “no-action” alternative was eliminated from further consideration.
5. *A listing of mitigation, stipulations and other controls:* A list of enforceable permit conditions and a complete permit analysis, including Best Available Control Technology (BACT) determinations, would be contained in MAQP #1821-27.
6. *Regulatory effects on private property:* The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined that the permit conditions are reasonably necessary to ensure compliance with applicable requirements and to demonstrate compliance with those requirements and do not unduly restrict private property rights.

7. The following table summarizes the potential physical and biological effects of the proposed project on the human environment. The "no action alternative" was discussed previously.

		Major	Moderate	Minor	None	Unknown	Comments
A	Terrestrial and Aquatic Life and Habitats			X			Yes
B	Water Quality, Quantity and Distribution			X			Yes
C	Geology and Soil Quality, Stability and Moisture			X			Yes
D	Vegetation Cover, Quantity and Quality			X			Yes
E	Aesthetics				X		Yes
F	Air Quality			X			Yes
G	Unique Endangered, Fragile or Limited Environmental Resource			X			Yes
H	Demands on Environmental Resource of Water, Air and Energy			X			Yes
I	Historical and Archaeological Sites			X			Yes
J	Cumulative and Secondary Impacts			X			Yes

**SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS:**

The following comments have been prepared by the Department.

A. Terrestrial and Aquatic Life and Habitats:

This permitting action could have a minor effect on terrestrial and aquatic life and habitats, as the proposed projects would include modification of existing emission units and additions of new emissions units. Impacts to terrestrial and aquatic life and habitats may occur as a result of these increased emissions. However, the emissions increases for the project fall below significance levels identified within the rules associated with Prevention of Significant Deterioration (PSD). Additionally, the permitting action would result in the incorporation of the most current facility and emissions information available. The overall emissions would remain within the facility-wide emissions caps established in MAQP #1821-05 in 2000 and updated in 2004 as part of MAQP #1821-11. Further, the projects would ultimately take place on industrial property that has already been disturbed. Therefore, only minor impacts to terrestrial and aquatic life and habitats are anticipated.

B. Water Quality, Quantity, and Distribution:

While deposition of pollutants would occur, the Department determined that any impacts from deposition of pollutants would be minor. Furthermore, this action would not result in a change in the quality or quantity of ground water. There also would not be any changes in drainage patterns or new discharges associated with these projects. Therefore, minor impacts to water quality, quantity, and/or distribution are anticipated.

C. Geology and Soil Quality, Stability, and Moisture:

The proposed projects constitute of installation of emission sources on the same existing industrial site. Therefore, no additional disturbance would be created as a result of the proposed projects. While deposition of pollutants would occur, the Department

determined that any impacts from deposition of pollutants would be minor. Additionally, no unique geologic or physical features would be disturbed. Overall, the Department believes that any impact to the geology and soil quality, stability, and moisture would be minor.

D. Vegetation Cover, Quantity, and Quality:

The proposed projects would affect an existing, industrial property that has already been disturbed. No additional vegetation on the site would be disturbed for the project. However, possible increases in actual emissions of NO<sub>x</sub>, SO<sub>2</sub>, VOCs, Particulate Matter/particulate matter with an aerodynamic diameter of 10 microns or less ( PM/PM<sub>10</sub>/PM<sub>2.5</sub>), and Carbon Monoxide (CO) from historical emission levels may result in minor impacts to the diversity, productivity, or abundance of plant species in the surrounding areas. Overall, any impacts to vegetation cover, quantity, and quality would be minor.

E. Aesthetics:

The proposed modification to the facility would be constructed in areas that have previously been disturbed and would not result in any additional disturbance. Therefore, no impacts to aesthetics are anticipated.

F. Air Quality:

The proposed projects would include increases of NO<sub>x</sub>, SO<sub>2</sub>, VOC, PM/PM<sub>2.5</sub>/PM<sub>10</sub>, and CO emissions. However, the project emissions do not exceed “significance” threshold levels as outlined in the rules associated with PSD. CHS would be required to maintain compliance with the Billings/Laurel SO<sub>2</sub> State Implementation Plan (SIP), current permit conditions, and state and federal ambient air quality standards. Additionally, modeled levels of pollutants for the proposed project show compliance with the NAAQS and the MAAQS. While deposition of pollutants is anticipated, the Department has determined that any air quality impacts as a result of the deposition would be minor.

G. Unique Endangered, Fragile, or Limited Environmental Resources:

The Department, in an effort to assess any potential impacts to any unique endangered, fragile, or limited environmental resources in the initial proposed area of operation (South ½, Section 16, Township 2 South, Range 24 East in Yellowstone County), previously contacted the Natural Resource Information System – Montana Natural Heritage Program. Search results concluded there are seven species of concern within the area. The search area, in this case, is defined by the section, township, and range of the proposed site, with an additional 1-mile buffer. The known specie of concern includes the Yellowstone Cutthroat Trout (Sensitive).

This permitting action may result in minor impacts to unique endangered, fragile, or limited environmental resources. However, as described in Section 7.F. of this EA, pollutant emissions generated from the facility would have minimal impacts on air quality in the immediate and surrounding area because of the relatively small amount of pollution emitted. There would not be any additional impact to these resources because the project would occur at an already disturbed site.

H. Demands on Environmental Resource of Water, Air, and Energy:

As described in Section 7.B of this EA, this permitting action would have little or no effect on the environmental resource of water as there would be no additional discharges to groundwater or surface water associated with this permitting action.

As described in Section 7.F of this EA, the impact on the air resource in the area of the facility would be minor because the facility would be required to maintain compliance with other limitations affecting the overall emissions from the facility.

A minor impact to the energy resource is expected during the construction process involved with the proposed projects; however, this impact is temporary. Additional energy consumption as a result of new equipment installation is expected to be minimal by scale. Overall, the impact to the energy resource would be minor.

I. Historical and Archaeological Sites:

In an effort to identify any historical and archaeological sites near the proposed project area for previous projects, the Department contacted the Montana Historical Society, State Historic Preservation Office (SHPO). According to SHPO records, there have been a few previously recorded sites within the designated search locales. In addition to the sites there have been a few previously conducted cultural resource inventories done in the areas. The projects would occur within the boundaries of a previously disturbed industrial site. There is a low likelihood cultural properties will be impacted; therefore, any impacts to historical and archeological would be considered minor.

J. Cumulative and Secondary Impacts:

The proposed projects would include increases of NO<sub>x</sub>, SO<sub>2</sub>, VOC, PM/PM<sub>2.5</sub>/PM<sub>10</sub>, and CO emissions; however, cumulative and secondary impacts from this action are anticipated to be minor as the emissions do not exceed “significance” threshold levels on a per project basis as outlined in the rules associated with PSD. Additionally, as described in Section 7.F of this EA, the impact on the air resource in the area of the facility would be minor because the facility would be required to maintain compliance with other limitations affecting the overall emissions from the facility. Any cumulative or secondary impacts as a result of these projects are considered to be minor and overall emissions will remain within the facility-wide emissions caps.

8. The following table summarizes the potential economic and social effects of the proposed project on the human environment. The "no action alternative" was discussed previously.

		Major	Moderate	Minor	None	Unknown	Comments
A	Social Structures and Mores				X		Yes
B	Cultural Uniqueness and Diversity				X		Yes
C	Local and State Tax Base and Tax Revenue				X		Yes
D	Agricultural or Industrial Production				X		Yes
E	Human Health			X			Yes
F	Access to and Quality of Recreational and Wilderness Activities				X		Yes
G	Quantity and Distribution of Employment				X		Yes
H	Distribution of Population				X		Yes
I	Demands for Government Services			X			Yes
J	Industrial and Commercial Activity				X		Yes

		Major	Moderate	Minor	None	Unknown	Comments
K	Locally Adopted Environmental Plans and Goals				X		Yes
L	Cumulative and Secondary Impacts			X			Yes

**SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS:** The following comments have been prepared by the Department:

A. Social Structures and Mores:

The proposed projects would not cause a disruption to any native or traditional lifestyles or communities (social structures or mores) in the area because the projects would be constructed at a previously disturbed industrial site. The proposed projects would not change the nature of the site.

B. Cultural Uniqueness and Diversity:

The proposed projects would not cause a change in the cultural uniqueness and diversity of the area because the land is currently used as a petroleum refinery; therefore, the land use would not be changing. The use of the surrounding area would not change as a result of these projects.

C. Local and State Tax Base and Tax Revenue:

The refinery's overall capacity would not change as a result of the permitting action. In addition, no new employees would be needed for this project. Therefore, no impacts to the local and state tax base and tax revenue are anticipated from these projects.

D. Agricultural or Industrial Production:

The permitting action would not result in a reduction of available acreage or productivity of any agricultural land; therefore, agricultural production would not be affected. The refinery's overall capacity would not change as a result of the proposed projects. Therefore, industrial production would not be affected.

E. Human Health:

As described in Section 7.F of this EA, the impacts from this facility on human health would be minor because the emissions from the facility would increase, but not significantly from prior levels. The air quality permit for this facility would incorporate conditions to ensure that the facility would be operated in compliance with all applicable rules and standards. These rules and standards are designed to be protective of human health.

F. Access to and Quality of Recreational and Wilderness Activities:

The proposed projects would not have an impact on recreational or wilderness activities because the site is far removed from recreational and wilderness areas or access routes. The action would not result in any changes in access to and quality of recreational and wilderness activities.

G. Quantity and Distribution of Employment:

No change in the number of employees currently onsite would be anticipated as a result of the proposed projects. Therefore, the action would not have any impacts to the quantity and distribution of employment at the facility.

H. Distribution of Population:

This permitting action does not involve any significant physical or operational change that would affect the location, distribution, density, or growth rate of the human population. The distribution of population would not change as a result of this action.

I. Demands of Government Services:

The demands on government services would experience a minor impact. The primary demand on government services would be the acquisition of the appropriate permits by the facility and compliance verification with those permits.

J. Industrial and Commercial Activity:

The refinery's overall capacity would not change as a result of the proposed permitting action. Therefore, no impacts on industrial activity at CHS would be expected. Industrial and commercial activity in the neighboring area is not anticipated to be affected by issuing MAQP #1821-27.

K. Locally Adopted Environmental Plans and Goals:

This permitting action would not affect any locally adopted environmental plans or goals. CHS must continue to comply with the SIP and FIP and associated stipulations for the Billings/Laurel area. The Department is not aware of any locally adopted environmental plans and goals that would be impacted by this action.

L. Cumulative and Secondary Impacts:

Overall, any cumulative and secondary impacts from this project on the social and economic aspects of the human environment would be minor. The project is associated with an existing facility and would not change the culture or character of the area. Additionally, overall emissions will remain within the facility-wide emissions caps.

*Recommendation:* An Environmental Impact Statement (EIS) is not required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: All potential effects resulting from this permitting action would be minor; therefore, an EIS is not required. In addition, the source would be applying BACT and the analysis indicates compliance with all applicable air quality rules and regulations.

*Other groups or agencies contacted or which may have overlapping jurisdiction:* None.

*Individuals or groups contributing to this EA:* Department of Environmental Quality, Permitting and Compliance Division - Air Resources Management Bureau.

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