Air Quality Permit

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

Permit #1821-13
Application Complete: 12/19/05
Preliminary Determination Issued: 01/27/06
Department Decision Issued: 03/10/06
Permit Final: 03/28/06
AFS #: 111-0012

An air quality permit, 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 S½ 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:

1. A hydrodesulfurization (HDS) complex to desulfurize fluidized catalytic cracking unit feedstocks operated and controlled by CHS. A sulfur recovery unit (SRU) and tail gas treatment unit (TGTU) shall together utilize up to 70.7 long tons per day of equivalent sulfur obtained from the equipment installations to manufacture elemental sulfur.

   The general associated processes for the HDS complex at the CHS Laurel Refinery are listed below:

   a. Hydrogen Plant Reformer Heater (H-101), 175-foot stack

   b. Gas-Oil HDS Unit

      i. Reactor Charge Heater (H-201), 100-foot stack
      ii. Fractionator Feed Heater (H-202), 100-foot stack
      iii. Compressor Gas Engine (C-201B), 93.5-foot stack

   c. Amine Unit

   d. Sour Water Stripper (SWS) Unit

   e. SRU (Claus)

      i. Sulfur Reaction Furnace
      ii. Waste Heat Boiler
      iii. Reheater Furnace (E-407)
      iv. SRU Incinerator (INC-401), 150-foot stack
      v. the Zone D FCC Feed Hydrotreater

   f. TGTU

2. Boiler #10 - Natural gas/Refinery fuel gas fired, 99.9 million British thermal units per hour (MMBtu/hr).

3. Truck Loading Rack and Vapor Combustion Unit (VCU) - The product loading rack is used to transfer refinery products from tank storage to trucks, which transport the gasoline, diesel, or burner fuels to retail outlets.

4. No. 1 Crude Unit

5. Ultra Low Sulfur Diesel (ULSD) Unit and Hydrogen Plant

6. TGTU for Zone A's SRU #1 and SRU #2 trains

7. Naphtha Hydrotreater (NHT) Unit, including the NHT Charge Heater

8. Delayed Coker Unit

   a. Coker Charge Heater
   b. Coker Unit Flare
   c. Coker Unit SRU through Tail Gas Incinerator (TGI)
   d. Coker Solids Processing Operations
   e. Coker Unit Oily Water Sewer
   f. Coker Unit Cooling Tower

9. Replacement Boiler No. 11

10. Railcar Loading Rack

    a. Product Loading VCU
    b. Product Loading Fugitives

11. Fluidized Catalytic Cracking Unit (FCCU)

12. The CHS facility as a whole (as it relates to Plant-wide Applicability Limits (PALs). The refinery flare is not included.

B. Current Permit Action

On December 19, 2005, the Department of Environmental Quality (Department) received a complete application from CHS to build a new 15,000-barrel per day (BPD) delayed coker unit and associated equipment. The new delayed coker unit would allow 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 will be 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 would also produce 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 are subject to the requirements of 75-2-215, MCA and ARM 17.8.770, Additional Requirements for Incinerators. The analysis for those requirements is included in this permit action.

Section II: Limitations and Conditions for the HDS Complex

A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 Code of Federal Regulations (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 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 GGG - Standards of Performance for Equipment leaks of Volatile Organic Compounds (VOC) in Petroleum Refineries applies to the HDS unit.

4. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the HDS unit.

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 six consecutive minutes. This applies to the sources in the HDS complex (ARM 17.8.304 (2)).

C. Limitations on Individual Sources

1. <u>Old SWS</u>

The burning of old sour water stripper overhead (SWSOH) in the CO Boiler and the Main Crude Heater is prohibited (CHS Consent Decree Paragraphs 43 and 50, and Appendix A).

2. <u>Zone D SRU Incinerator Stack (E-407 & INC-401)</u>

a. SO_2 emissions from the Zone D SRU incinerator stack shall not exceed:

i. 33.0 tons/rolling 12-calendar month total,
ii. 125 ppm_{vd}, rolling 12-month average corrected to 0% oxygen, on a dry basis.
iii. 341.04 lb/day,
iv. 14.21 lb/hr, and
v. 250 ppm_{vd}, rolling 12-hour average corrected to 0% oxygen, on a dry basis.

b. CHS shall operate and maintain the TGTU on the Zone D SRU to limit SO_2 emissions from the Zone D SRU Incinerator stack (E-407 & INC-401) to no more than 125 ppm_{vd} on a rolling 12-month average corrected to 0% oxygen on a dry basis (ARM 17.8.752).

c. NO_x emissions from the Zone D SRU incinerator stack shall not exceed:

i. 3.5 tons/rolling 12-calendar month total,
ii. 19.2 lb/day, and
iii. 0.8 lb/hr.

d. Refinery fuel gas burned in the Zone D SRU reheater (E-407) and incinerator (INC-401) shall not exceed 0.10 grains of hydrogen sulfide (H_2S) per dry standard cubic foot per rolling three-hour average. Refinery fuel gas burned in E-407 and INC-401 shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average. CHS shall not fire fuel oil in this unit.

3. <u>Compressor Gas Engine Stack (C-201B)</u>

a. NO_x emissions from C-201B shall not exceed:

i. 30.43 tons/rolling 12-calendar month total, and
ii. 7.14 lb/hr.

b. CO emissions from C-201B shall not exceed:

i. 68.59 tons/rolling 12-calendar month total,
ii. 6.40 lb/hr when firing natural gas, and
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.

d. CHS shall only combust natural gas or propane in C-201B.

4. <u>Fractionator Feed Heater Stack (H-202)</u>

a. SO_2 emissions from H-202 shall not exceed (ARM 17.8.749):

i. 2.71 tons/rolling 12 calendar-month total, and
ii. 1.24 lb/hr.

b. NO_x emissions from H-202 shall not exceed (ARM 17.8.749):

i. 7.19 tons/rolling 12 calendar-month total, and
ii. 2.09 lb/hr.

c. CO emissions from H-202 shall not exceed (ARM 17.8.749):

i. 5.55 tons/rolling 12-calendar month total, and
ii. 1.61 lb/hr.

d. VOC emissions from H-202 shall not exceed 0.04 tons/rolling 12-calendar month total (ARM 17.8.749).

e. Refinery fuel gas burned in H-202 shall not exceed 0.10 grains of H_2S per dry standard cubic foot per rolling three-hour average. Refinery fuel gas burned in H-202 shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average. CHS shall not fire fuel oil in this unit (ARM 17.7.749).

f. The heat input for H-202 shall not exceed 205,860 MMBtu-HHV on a rolling 12-calendar month total (ARM 17.8.749).

5. Reactor Charge Heater Stack (H-201)

a. SO_2 emissions from H-201 shall not exceed (ARM 17.8.749):

i. 2.54 tons/rolling 12-calendar month total, and
ii. 1.16 lb/hr.

b. NO_x emissions from H-201 shall not exceed (ARM 17.8.749):

i. 6.73 tons/rolling 12-calendar month total, and
ii. 2.90 lb/hr.

c. CO emissions from H-201 shall not exceed (ARM 17.8.749):

i. 5.19 tons/rolling 12-calendar month total, and
ii. 2.23 lb/hr.

d. VOC Emissions from H-201 shall not exceed 0.16 tons/rolling 12-calendar month total (ARM 17.8.749).

e. Refinery fuel gas burned in H-201 shall not exceed 0.10 grains of H_2S per dry standard cubic foot per rolling three-hour average. Refinery fuel gas burned in H-201 shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average. CHS shall not fire fuel oil in this unit (ARM 17.8.749).

f. The heat input for H-201 shall not exceed 191,844 MMBtu-HHV on a rolling 12-calendar month total (ARM 17.8.749).

6. Reformer Heater Stack (H-101)

a. SO_2 emissions from H-101 shall not exceed:

i. 1.68 tons/rolling 12-calendar month total, and
ii. 2.15 lb/hr.

b. NO_x emissions from H-101 shall not exceed:

i. 27.16 tons/rolling 12-calendar month total, and
ii. 6.78 lb/hr.

c. CO emissions from H-101 shall not exceed:

   i. 13.93 tons/rolling 12-calendar month total, and
   ii. 4.51 lb/hr.

d. VOC emissions from H-101 shall not exceed 0.35 tons/rolling 12-calendar month total.

e. Refinery fuel gas burned in H-101 shall not exceed 0.10 grains of H_2S per dry standard cubic foot per rolling three-hour average. Refinery fuel gas burned in H-101 shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average. CHS shall not combust fuel oil in this unit.

D. Monitoring Requirements

1. CHS shall install and operate the following CEMS/continuous emission rate monitors (CERMS):

   a. <u>SRU Incinerator Stack (E-407/INC-401)</u>

      i. SO_2
      ii. O_2
      iii. Volumetric Flow Rate

   b. <u>Fuel Gas Monitoring</u>

      Continuous concentration (dry basis) monitoring of H_2S in refinery fuel gas burned in the combustion devices listed in Section II.C with the exception of refinery fuel gas streams with approved Alternative Monitoring Plans (AMP).

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 7 and Appendix F; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors.

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.

E. 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_2 and NO_x, and the results submitted to the Department in order to demonstrate compliance with the SO_2 and NO_x emission limits contained in Section II.C.2.a and b (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_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section II.C.3.a and b (ARM 17.8.105 and ARM 17.8.749).

3. The Fractionator Feed Heater Stack (H-202) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section II.C.4.b and c (ARM 17.8.105 and ARM 17.8.749).

4. The Reactor Charge Heater Stack (H-201) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section II.C.5.b and c (ARM 17.8.105 and ARM 17.8.749).

5. 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_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.C.6.b and c (ARM 17.8.105 and ARM 17.8.749).

6. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

7. The Department may require additional testing (ARM 17.8.105).

F. Compliance Determinations

1. In addition to the testing required in Section II.E, compliance determinations for hourly, 24-hour, and annual SO_2 limits for the SRU Incinerator stack shall be based upon CEMS data utilized for SO_2 as required in Section II.D.1.a.

2. Compliance determinations for SO_2 limits for the fuel gas fired units within the HDS shall be based upon monitor data for H_2S, as required in Section II.D.1.b 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_2 limits.

3. In addition to the testing required in Section II.E, compliance determinations for the emission limits applicable to the HDS complex sources listed in Sections II.C.1 through 6 shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test. 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 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).

4. Compliance with the opacity limitation listed in Section II.B shall be determined using EPA reference method 9 testing by a qualified observer.

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

1. CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for SO_2 from the emission rate monitor shall consist of a daily 24-hour average (ppm SO_2, corrected to 0% oxygen (O_2) 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:

   a. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates and 24-hour (daily) average concentration of H_2S in the refinery fuel gas burned at the permitted facilities.

   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 Sections II.C.2 through 6.

   d. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Sections II.C.2 through 6 (ARM 17.8.749).

   e. Reasons for any emissions in excess of those specifically allowed in Sections II.C.2 through 6 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

2. CHS shall document, by month, the total heat input (based on HHV) for H-201 and H-202. Within 30 days following the end of each month, CHS shall calculate the total heat input for the previous month on those unit. The monthly information will be used to verify compliance with the rolling 12-month limitations in Sections II.C.4.f and II.C.5.f. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

3. 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 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).

4. 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 emissions 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 information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

5. All records compiled in accordance with this permit must be maintained by CHS as a permanent business record for at least five 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).

H. 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 four hours (ARM 17.8.110).

Section III: Limitations and Conditions for #10 Boiler

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 #10 Boiler. 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 Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

3. Subpart J - Standards of Performance for Petroleum Refineries. The requirements of this Subpart will apply to the #10 Boiler as of November 1, 1997.

4. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the refinery fuel gas supply lines to the #10 Boiler.

B. Emission Limitations for #10 Boiler

1. H_2S concentration in the refinery fuel gas burned in the #10 Boiler shall not exceed 0.10 grains per dry standard cubic foot (gr/dscf) per rolling 3-hr average. Refinery fuel gas burned in the #10 Boiler shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average. Fuel oil burning is not allowed in this unit (ARM 17.8.340,ARM 17.8.749, and ARM 17.8.752).

2. SO_2 emissions shall not exceed 3.83 lb/hr (ARM 17.8.752).

3. NO_x emissions shall not exceed 0.058 pounds per million British thermal units (lb/MMBtu) fired and 5.79 lb/hr (ARM 17.8.752).

4. CO emissions shall not exceed 0.10 lb/MMBtu fired and 9.99 lb/hr (ARM 17.8.752).

5. VOC emissions shall not exceed 0.015 lb/MMBtu fired and 1.50 lb/hr (ARM 17.8.752).

6. Opacity shall not exceed 20%, averaged over any six consecutive minutes (ARM 17.8.304).

7. The #10 Boiler shall not exceed 99.90 MMBtu/hour of heat input. The boiler shall be fitted with low NO_x burners with flue gas recirculation (FGR) and have a minimum stack height of 75 feet above ground level (ARM 17.8.340 and ARM 17.8.749).

C. Monitoring Requirements

1. CHS shall install, operate, and maintain a continuous H_2S concentration monitor, including a data acquisition system, to monitor and record the H_2S concentration of all refinery fuel gas burned in the #10 Boiler (ARM 17.8.340).

2. CHS shall install, operate, and maintain a continuous fuel gas flow rate meter, including a data acquisition system, to monitor and record the fuel flow rate of all fuel gas burned in the #10 Boiler (ARM 17.8.749).

3. The continuous H_2S concentration monitor shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, Appendix B, Performance Specifications 6 and 7, and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.340).

4. The continuous fuel gas flow rate meter shall meet the following specifications (ARM 17.8.749):

   a. For each hour when the unit is combusting fuel, measure and record the flow of fuel combusted by the unit. Measure the flow of fuel with an in-line fuel flow meter and automatically record the data with a data acquisition and handling system.

b. Each fuel flow meter used shall meet a flow meter accuracy of 2.0% of the upper range value (i.e., maximum calibrated fuel flow rate), either by design or as calibrated and as measured under laboratory conditions by the manufacturer, by an independent laboratory, or by the owner or operator.

c. The fuel gas flow rate meter shall meet the Fuel Gas Flow meter Calibration and Quality Assurance Procedures outlined in Attachment C.

D. Testing Requirements

1. The #10 Boiler shall be tested for NO_x, CO, and VOC concurrently and the results submitted to the Department in order to demonstrate compliance with the NO_x, CO, and VOC limits contained in Section III.B within 60 days after achieving the maximum production rate at which the unit will be operated, but not later than 180 days after start up of the #10 Boiler (ARM 17.8.105 and ARM 17.8.106).

2. The #10 Boiler shall be tested for NO_x, CO, and VOC concurrently and the results submitted to the Department in order to demonstrate compliance with the NO_x, CO, and VOC limits contained in Section III.B within 60 days after start up of the boiler on refinery fuel gas (ARM 17.8.105 and ARM 17.8.106).

3. The #10 Boiler shall be tested for NO_x, CO, and VOC concurrently at a minimum of every five 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).

4. 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 of Section III.E (ARM 17.8.749).

5. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

6. The Department may require additional testing (ARM 17.8.105).

E. Compliance Determinations

1. Compliance determinations for SO_2 and H_2S limits for the #10 Boiler shall be based upon continuous H_2S concentration monitor data and fuel gas flow meter data as required in Section III.C. This compliance method, using H_2S concentration monitors data and fuel gas flow meter data, will apply to the #10 Boiler as of November 1, 1997 (ARM 17.8.749).

2. In addition to the testing required in Section III.D, compliance determinations for NO_x, CO, and VOC emission limits for the #10 Boiler shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test of each fuel being combusted. New emission factors shall

become effective within 60 days after the completion of a source test. Firing Boiler #10 solely on natural gas shall demonstrate compliance with the applicable VOC limits (ARM 17.8.749).

3. 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).

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

1. CHS shall provide quarterly emission reports using data from continuous H_2S concentration monitors and fuel gas flow meters. Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by the Department (ARM 17.8.340). The quarterly report shall also include the following:

   a. SO_2 emission data from the refinery fuel gas system continuous H_2S concentration monitor and continuous fuel gas flow rate meter required by Section III.C.2 and 3. The SO_2 emission rates shall be reported for the following averaging periods:

      i. Average lb/hr per calendar day,
      ii. Total lb per calendar day, and
      iii. Total tons per month.

   b. NO_x emission data from the continuous fuel gas flow rate meter and the emission factors developed from the most recent compliance source test required by Section III.C.2 and D.1 and 3. The NO_x emission rates shall be reported for the following averaging periods:

      i. Average lb/hr per calendar day,
      ii. Total lb per calendar day, and
      iii. Total tons per month.

   c. The daily and monthly total fuel gas consumption used to calculate the emission rates for boiler #10 shall be reported.

   d. Source or unit operating time during the reporting period and quarterly refinery fuel gas and natural gas consumption rates and 24-hour (daily) average concentration of H_2S in the refinery fuel gas burned at the permitted facility.

   e. Monitoring downtime that occurred during the reporting period.

   f. An excess emission summary, which shall include excess emissions (lb/hr) for each pollutant and excess H_2S concentrations (gr/dscf) identified in Section III.B.

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

2. CHS shall submit quarterly emission reports within 30 days of the end of each calendar quarter.

3. Copies of quarterly emission reports, excess emissions, emission testing reports and other reports required by Sections III.D and III.F.1 shall be submitted to both the Billings regional office and the Helena office of the Department.

4. CHS shall comply with the reporting and recordkeeping requirements in 40 CFR 60.7 and 40 CFR 60.48c (a, g, and i). The maximum design heat input capacity shall be based on the highest gross calorific value (GCV) of each fuel to be combusted in boiler #10. CHS shall submit certification from the boiler manufacturer of the maximum design heat input capacity for the installed boiler. This certification shall include all design criteria used in determining the maximum design heat input capacity and provide reasons why this rate could not be exceeded. The Department may require recordkeeping and reporting requirements that may be necessary to demonstrate, on a continuing basis, that this maximum heat input capacity value is not being exceeded at any time.

5. 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).

6. All records compiled in accordance with this permit must be maintained by CHS as a permanent business record for at least five 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).

7. 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 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 17.8.340 and ARM 17.8.749):

1. Date of commencement of construction of the #10 Boiler within 30 days after commencement of construction.

2. Anticipated date of start up of the #10 Boiler, 30 to 60 days prior to the anticipated start-up date.

3. Actual date of start up of the #10 Boiler within 15 days after the actual start-up date.

4. Actual date of start up of the #10 Boiler on refinery fuel gas within 15 days after the actual start-up date on refinery fuel gas.

5. Complete and submit Section 5.0 (Emitting Unit/Process Information) of the Montana Department of Environmental Quality Permit Application for Sources of Air Pollution. This information shall be submitted upon CHS's selection decision of a boiler model, but before commencement of construction. This in no way eliminates the need for a permit alteration if the specifications for the selected boiler are different from the information submitted with the permit application.

6. 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 IV: Limitations and Conditions for the Product Loading Rack 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, National Emission Standards for Hazardous Air Pollutants (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 - NESHAP from Petroleum Refineries shall apply to, but not be limited to, the product loading rack and VCU.

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).

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, 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 two 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 three 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 VCU stack shall be 35 feet above grade (ARM 17.8.749).

B. Emission Limitations for the 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_x 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 enclosed VCU any visible emissions that exhibit an opacity of 20% or greater over any six consecutive minutes (ARM 17.8.304(2)).

C. 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 flare tip, 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 60.482-1 through 60.482-10.

D. 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 initially tested for VOCs, and compliance

demonstrated with the emission limitation contained in Section IV.B.1 within 180 days of initial startup and continue on an every five-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 initially tested for CO and NO_x, concurrently, and compliance demonstrated with the CO and NO_x emission limitations contained in Section IV.B.2 and 3 within 180 days of initial start up (ARM 17.8.105).

4. Fuel flow rates, production information, and any other data the Department believes is necessary shall be recorded during the performance of source tests (ARM 17.8.749).

5. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

6. The Department may require additional testing (ARM 17.8.105).

E. Operational and Emission Inventory Reporting Requirements

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

   a. 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.

   b. Subpart CC - CHS shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63.654.

2. 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 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).

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 emissions 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 information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

F. Notification Requirements

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

1. Date of commencement of construction of the product loading rack VCU within 30 days after the commencement of construction.

2. Anticipated start-up date of the product loading rack VCU within 30 to 60 days prior to the actual start-up date.

3. Actual start-up date of the product loading rack VCU within 15 days after the actual start-up date.

4. All compliance source tests as required by the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

5. 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 limitations or can be expected to last for a period greater than four hours (ARM 17.8.110).

Section V: 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 the Petroleum Refineries applies to the various new pumps, valves, flanges, and other equipment in Hazardous Air Pollutant (HAP) service within the No. 1 Crude Unit (40 CFR 63, Subpart CC: Maximum Achievable Control Technology (MACT) Standards for Petroleum Refineries).

B. Emission Control Requirements for No. 1 Crude Unit (ARM 17.8.752):

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.

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 two years.

C. Testing Requirements

1. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

2. The Department may require testing (ARM 17.8.105).

D. 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 five years following the date of the measurement, must be available at the plant site for inspection by the Department, 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).

E. 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 17.8.340 and ARM 17.8.749):

1. Date of commencement of the No. 1 Crude Unit Enhancement Project within 30 days after commencement of construction.

2. Actual date of start up of the No. 1 Crude Unit within 15 days after the actual start-up date.

3. 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 VI: 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 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.

4. 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 brought into gasoline service.

3. Subpart DDDDD – Industrial Boilers and Process Heaters shall apply to, as applicable, but not be limited to, the Reactor Charge Heater (H-901), the Fractionation Heater (H-902), and the Hydrogen Reformer Heater (H-1001).

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 six consecutive minutes. This applies to the sources in the ULSD Unit and Hydrogen Plant (ARM 17.8.304 (2)).

E. Limitations on Individual Sources (ARM 17.8.752)

1. Reactor Charge Heater H-901

a. SO_2 emissions from H-901 shall not exceed:

i. 1.96 tons/rolling 12-calendar month total, and
ii. 0.90 lb/hr.

b. NO_x emissions from H-901 shall not exceed:

i. 2.19 tons/rolling 12-calendar month total, and
ii. 0.50 lb/hr.

c. CO emissions from H-901 shall not exceed:

i. 9.00 tons/rolling 12-calendar month total, and
ii. 2.05 lb/hr.

d. VOC Emissions from H-901 shall not exceed 0.59 tons/rolling 12-calendar month total.

e. Refinery fuel gas burned in H-901 shall not exceed 0.10 grains of H_2S per dry standard cubic foot per rolling three-hour average. Refinery fuel gas burned in H-901 shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average. CHS shall not fire fuel oil in this unit (ARM 17.8.749).

2. Fractionator Reboiler H-902

a. SO_2 emissions from H-902 shall not exceed:

i. 3.95 tons/rolling 12-calendar month total, and
ii. 1.80 lb/hr.

b. NO_x emissions from H-902 shall not exceed:

i. 4.40 tons/rolling 12-calendar month total, and
ii. 1.00 lb/hr.

c. CO emissions from H-902 shall not exceed:

i. 8.50 tons/rolling 12-calendar month total, and
ii. 1.94 lb/hr.

d. VOC Emissions from H-902 shall not exceed 1.19 tons/rolling 12-calendar month total.

f. Refinery fuel gas burned in H-902 shall not exceed 0.10 grains of H_2S per dry standard cubic foot per rolling three-hour average. Refinery fuel gas burned in H-902 shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average. CHS shall not fire fuel oil in this unit (ARM 17.8.749).

3. Reformer Heater H-1001

a. SO_2 emissions from H-1001 shall not exceed:

i. 12.69 tons/rolling 12-calendar month total, and
ii. 5.80 lb/hr.

b. NO_x emissions from H-1001 shall not exceed:

i. 28.31 tons/rolling 12-calendar month total, and
ii. 6.46 lb/hr.

c. CO emissions from H-1001 shall not exceed:

i. 14.15 tons/rolling 12-calendar month total, and
ii. 3.23 lb/hr.

d. VOC Emissions from H-1001 shall not exceed 3.82 tons/rolling 12-calendar month total.

e. Refinery fuel gas burned in H-1001 shall not exceed 0.10 grains of H_2S per dry standard cubic foot per rolling three-hour average. Refinery fuel gas burned in H-1001 shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average. CHS shall not fire fuel oil in this unit. (ARM 17.8.749).

F. Monitoring Requirements (ARM 17.8.340).

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

a. Fuel Gas Monitoring

CHS shall conduct continuous concentration (dry basis) monitoring of H_2S in refinery fuel gas burned in the combustion devices listed in Sections VI.E.1, 2, and 3, or the requirements of 40 CFR 60.105(3), or another method as approved by the Department.

b. Pressure Swing Absorption (PSA) Tail Gas Monitoring

CHS shall conduct continuous concentration (dry basis) monitoring of H_2S in the PSA tail gas line upstream of the combustion device listed in Section VI.E.3. In place of a continuous monitor, an Alternative Monitoring Plan, as approved by the Department, or the requirements of 40 CFR 60.105(3), may be implemented.

2. 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 a feed stream from the existing MDU process feeds including, raw diesel from #1 and #2 Crude Units, hydrotreated diesel from the Gas Oil Hydrotreater, light cycle oil from the Fluidized Catalytic Cracking Unit, and burner fuel from the #1 and #2 Crude units, is first introduced into the ULSD Unit and Hydrogen Plant. 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

1. The Reactor Charge Heater (H-901) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section VI.E.1.b and c (ARM 17.8.105 and ARM 17.8.749).

2. The Fractionator Reboiler (H-902) shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section VI.E.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_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section VI.E.3.b and c (ARM 17.8.105 and ARM 17.8.749).

4. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

5. The Department may require additional testing (ARM 17.8.105).

H. Compliance Determinations (ARM 17.8.749).

1. Compliance determinations for the SO_2 limits for the fuel gas fired units within the ULSD Unit and the Hydrogen Plant shall be based upon fuel firing rates and the H_2S monitor data as required in Section VI.F.1.a, if these units are fired on refinery fuel gas. Firing these units solely on natural gas shall demonstrate compliance with the applicable SO_2 limits.

2. In addition to the testing required in Section VI.G, compliance determinations for the emission limits applicable to the ULSD Unit and Hydrogen Plant sources listed in Sections VI.E.1 through 3 shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test. 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 (ARM 17.8.749).

3. Compliance with the opacity limitation listed in Section VI.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)

1. 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:

   a. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates and 24-hour (daily) average concentration of H_2S in the refinery fuel gas and PSA tail gas burned at the permitted facilities and SO_2 in the H-1001 stack.

   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 VI.E.1 through 3.

   d. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in VI.E.1 through 3.

   e. Reasons for any emissions in excess of those specifically allowed in VI.E.1 through 3 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

2. 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 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).

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 emissions 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 information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

4. All records compiled in accordance with this permit must be maintained by CHS as a permanent business record for at least five years following the date of the

measurement, must be available at the plant site for inspection by the Department, the EPA, and the Yellowstone County Air Pollution Control Agency, and must be submitted to the Department upon request (ARM 17.8.749).

J. 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 17.8.340 and ARM 17.8.749):

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 four hours (ARM 17.8.110).

Section VII: 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 GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the TGTU fugitive piping equipment in VOC service.

4. 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 61, NESHAP. The following subparts, at a minimum, are applicable (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 FF – National Emission Standard for Benzene Waste Operations applies to the TGTU process wastewater streams. CHS will quantify the annual benzene quantity at the point of generation.

C. 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.

D. 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 six consecutive minutes. This applies to the sources in the TGTU (ARM 17.8.304 (2).

E. 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.

F. Limitations on Individual Sources

1. SO_2 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,
   b. 200 ppm, rolling 12-month average corrected to 0% oxygen, on a dry basis,
   b. 40.66 tons/rolling 12-month total,
   c. 11.60 lb/hr, and
   d. 278.40 lb/day.

2. CHS shall operate and maintain the TGTU on the Zone A SRU to limit SO_2 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_x emissions from the SRU-AUX-4 stack shall not exceed:

   a. 4.8 tons/rolling 12-calendar month total, and
   b. 1.09 lb/hr.

4. Refinery fuel gas burned in the Zone A SRU Incinerator (not to include the tail gas produced in the SRU/TGTU) shall not exceed 0.10 grains of hydrogen sulfide (H_2S) per dry standard cubic foot per rolling three-hour average. Refinery fuel gas burned in the Zone A SRU Incinerator (not to include the tail gas produced in the SRU/TGTU) shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average. CHS shall not fire fuel oil in this unit.

G. Monitoring Requirements

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

   a. <u>Zone A</u> <u>SRU-AUX-4 Stack</u> (CHS Inc, Consent Decree)

      i. SO_2
      ii. O_2
      iii. Volumetric Flow Rate

   b. <u>Fuel Gas Monitoring</u>

Continuous concentration (dry basis) monitoring of H_2S in refinery fuel gas burned in the combustion devices listed in Section VII.F.

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 7 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.

H. Testing Requirements

1. Initial testing shall be performed within 60 days of the date the TGTU achieves maximum production but not later than 180 days after start-up of the ULSD project 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_2, and shall be tested on an every five-year basis, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x. The results shall be submitted to the Department in order to demonstrate compliance with the SO_2 and NO_x emission limits contained in Sections VII.F.1, 2, and 3 (ARM 17.8.105 and ARM 17.8.749).

2. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

3. The Department may require additional testing (ARM 17.8.105).

I. Compliance Determinations (ARM 17.8.749)

1. In addition to the testing required in Section VII.H, compliance determinations for ppm concentration, hourly, 3-hour, 24-hour, rolling 12-month, and annual SO_2 limits for the SRU-AUX-4 Stack shall be based upon CEMS data utilized for SO_2 as required in Section VII.G.1.a.

2. Compliance determinations for SO_2 limits for the fuel gas fired units within Zone A shall be based upon monitor data for H_2S, as required in Section VII.G.1.b 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_2 limits.

3. Compliance with the opacity limitation listed in Section VII.D shall be determined using EPA reference method 9 testing by a qualified observer.

4. Compliance determinations for hourly, 24-hour, and annual SO_2 limits for the Zone A Sulfur Recovery Plants shall be based upon CEMS data utilized for SO_2 as

required in Section VII.G.1.c.

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

1. Emission reporting for SO_2 from the emission rate monitors shall consist of a daily 24-hour average concentration (ppm SO_2, corrected to 0% O_2) 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:

   a. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates and 24-hour (daily) average concentration of H_2S in the refinery fuel gas burned at the permitted facility.

   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 Section VII.F.

   d. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section VII.F.

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

2. 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 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).

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 emissions 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

information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

4. All records compiled in accordance with this permit must be maintained by CHS as a permanent business record for at least five years following the date of the measurement, must be available at the plant site for inspection by the Department, the EPA, and the Yellowstone County Air Pollution Control Agency, and must be submitted to the Department upon request (ARM 17.8.749).

K. 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 17.8.340 and ARM 17.8.749):

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 four hours (ARM 17.8.110).

Section VIII: 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_2 and CO. Subpart J requirements for PM and opacity will become applicable when the third air-blower in the FCCU starts up, or as required under the CHS Consent Decree (CHS Consent Decree paragraphs 55, 57, and Appendix F).

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

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_2 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. Starting December 31, 2006, CO emissions from the FCCU Regenerator Stack shall not exceed 150 ppm at 0% O_2 per rolling 365-day time period (CHS Consent Decree paragraph 41).

c. The 7-day rolling average SO_2 emissions from the FCCU Regenerator Stack shall not exceed 50 ppm by volume (corrected to 0% O_2) or the 7-day rolling average FCCU fresh feed total sulfur content shall not exceed 0.30 percent by weight. Starting December 31, 2007, CHS shall also comply with an SO_2 concentration limit of 25 ppm_{vd} at 0% O_2 on a 365-day rolling average basis (CHS Consent Decree paragraphs 32-33).

d. PM emissions from the FCCU shall be controlled with a third stage separator (if approved by EPA under the CHS Consent Decree), an ESP, or a wet gas scrubber. Following the startup of the third air blower in the FCCU, PM emissions from the FCCU shall not exceed 1.0 lb PM/1000 lb of coke burned (ARM 17.8.752).

e. NO_x emissions from the FCCU shall not exceed 161.1 tons per 12-month rolling average (limit is based on 90 ppm_{vd} at 0% oxygen on a 12-month rolling average) (ARM 17.8.752).

2. FCC Charge Heater

a. NO_x emissions from the FCC Charge Heater shall not exceed (ARM 17.8.749):

i. 22.87 tons/rolling 12-calendar month total, and
ii. 6.27 lb/hr.

b. CO emissions from the FCC Charge Heater shall not exceed (ARM 17.8.749):

i. 19.21tons/rolling 12-calendar month total, and
ii. 5.26 lb/hr.

E. Monitoring Requirements

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

a. Fuel Gas Monitoring

Continuous concentration (dry basis) monitoring of H_2S in refinery fuel gas burned in the combustion device listed in Section VIII.D.2.

b. FCCU Regenerator Stack (CHS Consent Decree)

i. CO
ii. NO_x
iii. SO_2
iv. O_2
v. Opacity (40 CFR 63, Subpart UUU)

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 7 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.

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. Following the startup of the third blower in the FCCU, the FCC Charge Heater shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section VIII.D.2.a and b (ARM 17.8.105 and ARM 17.8.749).

3. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

4. The Department may require additional testing (ARM 17.8.105).

G. Compliance Determinations

1. Compliance with the opacity limitation listed in Section VIII.B shall be determined using EPA reference method 9 observations by a qualified observer or a certified continuous opacity monitor system (COMS).

2. Compliance determinations for CO limits for the FCCU Regenerator Stack shall be based upon CEMS data utilized for CO as required in Section VIII. C.

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

1. CHS shall submit quarterly emission reports to the Department based on data from the installed CEMS/CERMS. Emission reporting for CO from the emission monitor 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:

   a. Source or unit operating time during the reporting period and either the 7-day rolling average SO_2 concentration (ppmv) or the 7-day rolling average sulfur content (% by weight) in the FCCU feed.

   b. The daily average lb PM per 1000 lb of coke burned and the daily and monthly NO_x totals in lbs.

   c. Monitoring downtime that occurred during the reporting period.

   d. A summary of excess emissions or applicable concentrations for each pollutant and the averaging period identified in Section VIII.C.

   e. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section VIII.C (ARM 17.8.749).

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

2. 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 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).

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 emissions 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 information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

4. All records compiled in accordance with this permit must be maintained by CHS as a permanent business record for at least five 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).

I. 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 IX: Limitations and Conditions for Fuel Gas 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, 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 as applicable, with the exception of the existing refinery flare. The flare will be subject to Subpart J once EPA has approved all proposed Alternative Monitoring Plans (CHS Consent Decree paragraphs 55 and 57).

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 six consecutive minutes (ARM 17.8.304 (2)).

C. Limitations on Fuel Gas Combustion Devices

1. Prior to the startup of any of the following units: Coker Charge Heater, Coker SRU/TGTU/TGI, or Boiler #11 or the completion of the Zone D SRU debottleneck, SO_2 emissions from the combustion of alkylation unit polymer and fuel oil in all combustion devices is limited to 300 tons per rolling 365-day time period. Following the startup of any of the following units: Coker Charge Heater, Coker SRU/TGTU/TGI, or Boiler #11 or the completion of the Zone D SRU debottleneck, SO_2 emissions from the combustion of alkylation unit polymer and fuel oil in all combustion devices is limited to 137.3 tons per rolling 365-day time period. During documented periods of natural gas curtailment, SO_2

emissions from the burning of any liquid fuels in heaters shall not be included in the 365-day average (CHS Consent Decree paragraph 59 and ARM 17.8.749).

2. Refinery fuel gas burned in fuel combustion devices shall not exceed 0.10 grains of H_2S per dry standard cubic foot per rolling three-hour average. Refinery fuel gas burned in fuel combustion devices shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average (ARM 17.8.749).

D. Monitoring Requirements

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

<u>Fuel Gas Monitoring</u>

Continuous concentration (dry basis) monitoring of H_2S 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 Consent Decree required AMP's 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, Subparts J, 60.100-108 and Appendix B, Performance Specifications 2, 3, 6, and 7 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.

E. Testing Requirements

1. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

2. The Department may require additional testing (ARM 17.8.105).

F. Compliance Determinations

1. Compliance determinations for SO_2 limits for the fuel gas fired units within the refinery shall be based upon monitor data for H_2S, as required in Section VIII.D.1.a 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_2 limits.

2. Compliance determinations for the SO_2 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_2 SIP and Appendix G of the CHS Consent Decree.

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

1. CHS shall submit quarterly emission reports to the Department. Emission reporting for SO_2 generated from the combustion of fuel oil and alkylation unit polymer shall consist of a daily 365-day rolling average (tons/year) 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:

a. Source or unit operating time during the reporting period (Alkylation Unit and boilers burning fuel oil and 24-hour (daily) average concentration of H_2S in the refinery fuel gas burned at the permitted facilities.

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 Section IX.C.

d. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section IX.C (ARM 17.8.749).

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

f. For those refinery fuel gas streams covered by AMPs, the report should identify instances where AMP conditions were not met.

2. 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 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).

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 emissions 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 information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

4. All records compiled in accordance with this permit must be maintained by CHS as a permanent business record for at least five 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).

H. 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 X: Limitations and Conditions for the Delayed Coker 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 NHT Charge Heater, the Coker Charge Heater, and the Coker Unit SRU/TGTU/TGI.

3. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to 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 new Coker Unit SRU/TGTU/TGI.

4. Subpart DDDDD – Industrial Boilers and Process Heaters shall apply to, but not be limited to, the NHT Charge Heater, and the Coker Charge Heater.

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 six 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

a. SO_2 emissions from the NHT Charge Heater shall not exceed (ARM 17.8.752):

i. 0.6 tons/rolling 12-calendar month total, and
ii. 0.27 lb/hr.

b. NO_x emissions from the NHT Charge Heater shall not exceed (ARM 17.8.752):

i. 2.5 tons/rolling 12-calendar month total, and
ii. 0.57 lb/hr.

c. CO emissions from the NHT Charge Heater shall not exceed 400 ppm_{vd} at 3% oxygen on a three-hour basis (ARM 17.8.752, ARM 17.8.342, and 40 CFR 63, Subpart DDDDD).

d. VOC Emissions from the NHT Charge Heater shall not exceed 0.3 tons/rolling 12-calendar month total (ARM 17.8.752).

e. Refinery fuel gas burned in the NHT Charge Heater shall not exceed 0.10 grains of H_2S per dry standard cubic foot per rolling three-hour average. Refinery fuel gas burned in the NHT Charge Heater shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average. 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

a. SO_2 emissions from the Coker Charge Heater shall not exceed (ARM 17.8.752):

i. 5.8 tons/rolling 12-calendar month total, and
ii. 2.67 lb/hr.

b. NO_x emissions from the Coker Charge Heater shall not exceed (ARM 17.8.752):

i. 24.4 tons/rolling 12-calendar month total, and
ii. 5.6 lb/hr.

c. CO emissions from the Coker Charge Heater shall not exceed (ARM 17.8.752):

i. 400 ppm_{vd} at 3% oxygen on a 30-day rolling average (ARM 17.8.342, and 40 CFR 63, Subpart DDDDD),
ii. 31.2 tons/rolling 12-calendar month total, and

iii. 7.12 lb/hr.

d. VOC Emissions from the Coker Charge Heater shall not exceed 1.3 tons/rolling 12-calendar month total (ARM 17.8.752).

e. Refinery fuel gas burned in the Coker Charge Heater shall not exceed 0.10 grains of H_2S per dry standard cubic foot per rolling three-hour average. Refinery fuel gas burned in the Coker Charge Heater shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average. 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 (ARM 17.8.752).

a. With respect to the Coker unit flare, 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 four hours (ARM 17.8.110).

4. VOC emissions from the Sour Water Storage Tank 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 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. CHS shall maintain a clearance between the top of the coke pile and the enclosure walls at all times (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 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).

7. Coker Unit SRU/TGTU/TGI

   a. SO_2 emissions from the Coker Unit 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), and
      ii. 14.1 lb/hr (based on 250 ppm, rolling 3-hour average corrected to 0% oxygen, on a dry basis).

   b. CHS shall operate and maintain the TGTU on the Coker Unit to limit SO_2 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_x emissions from the Coker Unit SRU/TGTU/TGI shall not exceed (ARM 17.8.749):

      i. 4.16 tons/rolling 12-calendar month total, and
      ii. 0.95 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); and
      ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO_2 (ARM 17.8.752).

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

E. Monitoring requirements

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

   a. <u>Fuel Gas Monitoring</u>

      CHS shall conduct continuous concentration (dry basis) monitoring of H_2S in refinery fuel gas burned in the NHT Charge Heater and the Coker Charge Heater, or the requirements of 40 CFR 60.105(3), or another method as approved by the Department.

   b. <u>Coker Unit SRU/TGTU/TGI (Billings/Laurel SO_2 SIP)</u>

      i. SO_2 (40 CFR 60, Subpart J)
      ii. O_2 (40 CFR 60, Subpart J)
      iii. Volumetric Flow Rate (Billings/Laurel SO_2 SIP)

   c. <u>Coker Charge Heater (40 CFR 63, Subpart DDDDD)</u>

i. CO

ii. O_2

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 7 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. CEMS required by 40 CFR 63, Subpart DDDDD shall comply with all applicable site specific monitoring plans, performance testing and reporting provisions.

3. The Delayed Coker Unit SO_2 CEMS, stack gas volumetric flow rate CEMS, H_2S refinery fuel gas CEMS and fuel gas flow rate meters shall comply with all applicable requirements of the Billings/Laurel SO_2 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.

F. Testing Requirements

1. The NHT Charge Heater shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section X.D.1.b and c (ARM 17.8.105 and ARM 17.8.749).

2. The Coker Charge Heater shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Section X.D.2.b and c (ARM 17.8.105 and ARM 17.8.749).

3. Initial SO_2 testing shall be performed within 60 days of the date the Coker Unit SRU/TGTU/TGI achieves maximum production. The Coker Unit SRU/TGTU/TGI stack shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department for SO_2, 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_x. The results shall be submitted to the Department in order to demonstrate compliance with the SO_2 and NO_x emission limits contained in Section X.D.7.a and b, respectively (ARM 17.8.105 and ARM 17.8.749).

4. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

5. The Department may require additional testing (ARM 17.8.105).

G. Compliance Determinations (ARM 17.8.749).

1. Compliance determinations for the SO_2 limits for the fuel gas fired units within the Delayed Coker Unit and related projects shall be based upon fuel firing rates and the H_2S monitor data as required in Section X.E.1.a, if these units are fired on refinery fuel gas. Firing these units solely on natural gas shall demonstrate compliance with the applicable SO_2 limits.

2. In addition to the testing required in Section X.F, compliance determinations for the emission limits applicable to the NHT Charge Heater and the Coker Charge Heater listed in Sections X.D.1 through 2 shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test. 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 (ARM 17.8.749).

3. In addition to the testing required in Section X.F, compliance determinations for ppm concentration, hourly, and rolling 12-month SO_2 limits for the Coker Unit SRU/TGTU/TGI shall be based upon CEMS data utilized for SO_2 as required in Section X.E.1.c. (ARM 17.8.749).

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

1. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each calendar quarter. Emission reporting for SO_2 from the emission rate monitors shall consist of a daily 24-hour average concentration (ppm SO_2, corrected to 0% O_2) 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 and 24-hour (daily) average concentration of H_2S in the refinery fuel gas burned at the permitted facilities.

   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 X.D.1 through 3 and 8.

   d. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section X.G.

   e. Reasons for any emissions in excess of those specifically allowed in Section X.D.1 through 3 and 8 with mitigative measures utilized and corrective actions taken to prevent a recurrence of the situation.

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 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 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).

4. 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 emissions 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 information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

5. All records compiled in accordance with this permit must be maintained by CHS as a permanent business record for at least five years following the date of the measurement, must be available at the plant site for inspection by the Department, the EPA, and the Yellowstone County Air Pollution Control Agency, and must be submitted to the Department upon request (ARM 17.8.749).

I. 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 17.8.340 and ARM 17.8.749):

1. Date of commencement of construction of the Delayed Coker Unit within 30 days after the commencement of construction.

2. Anticipated start-up date of the Delayed Coker Unit within 30 to 60 days prior to the actual start-up date.

3. Actual start-up date of the Delayed Coker Unit within 15 days after the actual start-up date.

4. All compliance source tests as required by the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

5. 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 four hours (ARM 17.8.110).

Section XI: Limitations and Conditions for the Replacement 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 the Replacement Boiler #11.

3. Subpart Db – Standards of Performance for Steam Generating Units applies to the Replacement Boiler #11.

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 DDDDD – Industrial Boilers and Process Heaters shall apply to, but not be limited to the Replacement Boiler #11.

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 six consecutive minutes. This applies to the sources in the Replacement Boiler #11 (ARM 17.8.304 (2)).

D. Limitations on Replacement Boiler #11

1. SO_2 emissions from Replacement Boiler #11 shall not exceed (ARM 17.8.752):

   a. 8.0 tons/rolling 12-calendar month total, and
   b. 3.63 lb/hr.

2. NO_x emissions from Replacement Boiler #11 shall not exceed (ARM 17.8.752):

   a. 16.6 tons/rolling 12-calendar month total, and
   b. 3.79 lb/hr.

3. CO emissions from Replacement Boiler #11 shall not exceed (ARM 17.8.752):

   a. 400 ppm_{vd} at 3% oxygen on a 30-day rolling average (ARM 17.8.342, and 40 CFR 63, Subpart DDDDD),
   b. 56.3 tons/rolling 12-calendar month total; and
   c. 12.85 lb/hr.

4. VOC Emissions from the Replacement Boiler #11 shall not exceed 4.5 tons/rolling 12-calendar month total (ARM 17.8.752).

5. Refinery fuel gas burned in Replacement Boiler #11 shall not exceed 0.10 grains of H_2S per dry standard cubic foot per rolling 3-hr average. Refinery fuel gas burned in the Replacement Boiler #11 shall not exceed 0.05 grains of H_2S per dry standard cubic foot per 12-month average. CHS shall not fire fuel oil in this unit. (ARM 17.8.340; 40 CFR 60, Subpart J; and ARM 17.8.752).

E. Monitoring requirements

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

a. <u>Fuel Gas Monitoring</u>

CHS shall conduct continuous concentration (dry basis) monitoring of H_2S in refinery fuel gas burned in the Replacement Boiler #11, or the requirements of 40 CFR 60.105(3), or another method as approved by the Department.

b. <u>Replacement Boiler #11</u>

i. NO_x (40 CFR 60, Subpart Db)
ii. O_2 (40 CFR 60, Subpart Db and 40 CFR 63, Subpart DDDDD)
iii. CO (40 CFR 60, Subpart DDDDD)

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 7 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. CEMS required by 40 CFR 63, Subpart DDDDD shall comply with all applicable site specific monitoring plans, performance testing and reporting provisions.

3. Stack gas volumetric flow rate CEMS, H_2S refinery fuel gas CEMS, and fuel gas flow rate meters shall comply with all applicable requirements of the Billings/Laurel SO_2 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.

F. Testing Requirements

1. The Replacement Boiler #11 shall be tested annually, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the NO_x and CO emission limits contained in Sections X.D.2 and 3 (ARM 17.8.105 and ARM 17.8.749).

2. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

3. The Department may require additional testing (ARM 17.8.105).

G. Compliance Determinations (ARM 17.8.749).

1. Compliance determinations for the SO_2 limits for the Replacement Boiler #11 shall be based upon fuel firing rates and the H_2S monitor data as required in Section X.E.1.a, if this unit is fired on refinery fuel gas. Firing this unit solely on natural gas shall demonstrate compliance with the applicable SO_2 limits.

2. In addition to the testing required in Section X.F, compliance determinations for the emission limits applicable to the Replacement Boiler #11 listed in Sections X.D.1 through 5 shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test. 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 (ARM 17.8.749).

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

1. 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:

   a. Source or unit operating time during the reporting period and quarterly fuel gas consumption rates and 24-hour (daily) average concentration of H_2S in the refinery fuel gas burned at the permitted facilities.

   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 X.D.1 through 3 and 8.

   d. Compliance determinations for hourly, 24-hour, and annual limits specifically allowed in Section X.G.

   e. 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.

2. 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 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).

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 emissions 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 information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

4. All records compiled in accordance with this permit must be maintained by CHS as a permanent business record for at least five years following the date of the measurement, must be available at the plant site for inspection by the Department, the EPA, and the Yellowstone County Air Pollution Control Agency, and must be submitted to the Department upon request (ARM 17.8.749).

I. 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 17.8.340 and ARM 17.8.749):

1. Actual start-up date of the Replacement Boiler #11 within 15 days after the actual start-up date.

2. All compliance source tests as required by the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

3. 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 four hours (ARM 17.8.110).

Section XII: 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, National Emission Standards for Hazardous Air Pollutants (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 – 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, 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_x 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_2 (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 XI.C.1 within 180 days of initial startup and continue on an every five-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).

4. The VCU shall be initially tested for CO and NO_x, concurrently, and compliance demonstrated with the CO and NO_x emission limitations contained in Section XI.C.2 and 3 within 180 days of initial start up (ARM 17.8.105).

5. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

6. The Department may require additional testing (ARM 17.8.105).

E. Operational and Emission Inventory Reporting Requirements

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 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. 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 emissions 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 information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

F. Notification Requirements

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

1. Date of commencement of construction of the railcar light product loading rack and VCU within 30 days after the commencement of construction.

2. Anticipated start-up date of the railcar light product loading rack and VCU within

30 to 60 days prior to the actual start-up date.

3. Actual start-up date of the railcar light product loading rack VCU within 15 days after the actual start-up date.

4. All compliance source tests as required by the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

5. 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 limitations or can be expected to last for a period greater than 4 hours (ARM 17.8.110).

Section XIII: Plant-wide Refinery Limitations and Conditions

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

1.	SO_2 emissions shall not exceed	2980.3 tons per year (TPY)
2.	NO_x emissions shall not exceed	999.4 TPY
3.	CO emissions shall not exceed	678.2 TPY
4.	VOC emissions shall not exceed	1967.5 TPY
5.	PM_{10} emissions shall not exceed	152.2 TPY
6.	PM emissions shall not exceed	162.2 TPY

B. Compliance Determination (ARM 17.8.749):

CHS shall determine the CO, NO_x, and VOC emissions for combustion sources by utilizing the 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_x, and VOC emissions in CHS's Permit #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.

1. Gas fired external combustion

a. SO_2

i. Calculation Basis: AP-42 Section 1-4 (7/98 revision) and complete conversion of fuel gas H_2S to SO_2
Key Parameters: Monthly fuel use (scf) per combustion unit and refinery fuel gas H_2S content from CEMS.

b. NO_x, CO, PM_{10}/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_2

      i. Calculation Basis: Methodology required in the Billings-Laurel SO_2 SIP and Appendix G of the CHS Consent Decree.
      ii. Key Parameters: Monthly fuel oil use (lb) per combustion unit, test for fuel oil Sulfur content pursuant to Billings-Laurel SO_2 SIP, and sulfur content and specific gravity of alkylation unit polymer pursuant to Appendix G of the CHS Consent Decree.

   b. NO_x, CO, PM_{10}/PM, VOC

      i. Calculation Basis: AP-42 Section 1-3 (9/98 revision including the 4/28/00 Errata)
      ii. Key Parameters: Monthly fuel oil use (lb) per combustion unit

3. Gas fired internal combustion

   a. SO_2

      i. Calculation Basis: AP-42 Section 1-4 (7/98 revision) and complete conversion of fuel gas H_2S to SO_2
      ii. Key Parameters: Monthly fuel use (scf) per combustion unit and fuel gas H_2S and Sulfur content

   b. NO_x, 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_{10}/PM: Not applicable – not a significant source

   d. VOC

      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

4. #10 Boiler

   a. SO_2

      i. Calculation Basis: Complete conversion of fuel gas H_2S to SO_2
      ii. Key Parameters: Monthly fuel use (scf) per combustion unit and refinery fuel gas H_2S content from CEMS

   b. NO_x

      i. Calculation Basis: Emission factors based on stack tests

ii. Key Parameters: NO_x stack tests, monthly fuel use (scf)

c. CO

i. Calculation Basis: Emission factors based on stack tests
ii. Key Parameters: CO stack tests, monthly fuel use (scf)

d. PM_{10}/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)

5. Zone D, ULSD Unit (900 Unit), Hydrogen Plant (1000 Unit), Delayed Coker Unit combustion sources, Replacement Boiler #11, and NHT Charge Heater

a. SO_2: Calculation Basis: CEMS data and methodology required in the Billings/Laurel SO_2 SIP

b. NO_x

i. Calculation Basis: Emission factors based on annual stack tests
ii. Key Parameters: NO_x stack tests, monthly fuel use (scf) per combustion unit

c. CO

i. Calculation Basis: Emission factors based on annual stack tests
ii. Key Parameters: CO stack tests, monthly fuel use (scf) per combustion unit

d. PM_{10}/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

6. Fugitive equipment leaks

   a. SO_2, NO_x, CO, PM_{10}/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

7. FCCU

   a. SO_2

      Calculation Basis: CEMS data and methodology required in CHS Consent Decree, NSPS Subpart J, and the Billings/Laurel SO_2 SIP

   b. NO_x

      Calculation Basis: CEMS data and methodology required in CHS Consent Decree, NSPS Subpart J, and FCCU Regenerator flue gas flow rate determined by the material balance described in the May 18, 2004, Montana DEQ and CHS Meeting Agenda and the May 28, 2004, Permit Application #1821-11

   c. CO

      Calculation Basis: CEMS data and methodology required in CHS Consent Decree and NSPS Subpart J, and FCCU Regenerator flue gas flow rate determined by the material balance described in the May 18, 2004, Montana DEQ and CHS Meeting Agenda and the May 28, 2004, Permit Application #1821-11

   d. PM_{10}/PM

      i. Calculation Basis: Site-specific emission factor from catalyst mass balance studies, stack test results and particle size distribution data
      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_2: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO_2 SIP

   b. NO_x

      i. Calculation Basis: Emission factors based on every five-year stack tests
      ii. Key Parameters: Every five-year NO_x stack test, monthly fuel use (scf)

   c. CO, PM_{10}/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_2: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO_2 SIP

   b. NO_x

      i. Calculation Basis: Emission factors based on annual stack tests
      ii. Key Parameters: Annual NO_x stack test, monthly fuel use (scf)

   c. CO, PM_{10}/PM, VOC: Not applicable – not a significant source

10. Delayed Coker Unit SRU Incinerator

   a. SO_2: Calculation Basis: CEMS data and methodology required in Billings/Laurel SO_2 SIP

   b. NO_x

      i. Calculation Basis: Emission factors based on every five-year stack tests
      ii. Key Parameters: Every five-year NO_x stack test, monthly fuel use (scf)

   c. CO, PM_{10}/PM, VOC: Not applicable – not a significant source

11. Wastewater

   a. SO_2, NO_x, CO, PM_{10}/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_2, NO_x, CO: Not applicable – not a source

    b. PM_{10}/PM: 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_2: Not applicable – not a source

    b. NO_x

        i. Calculation Basis: VCU stack tests for lb NO_x/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_{10}/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_2, NO_x, CO, PM_{10}/PM: Not applicable – not a source

    b. VOC

        i. Calculation Basis: EPA TANKS4.0
        ii. Key Parameters: Monthly volume of material throughput from yield accounting, material property data (VP, MW, etc.)

C. Reporting and Recordkeeping Requirements (ARM 17.8.749):

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

D. Testing Requirements

1. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

2. The Department may require testing (ARM 17.8.105).

E. 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 five years following the date of the measurement, must be available at the plant site for inspection by the Department, 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).

F. Notification Requirements

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 XIV: General Conditions

A. Inspection - The recipient 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 the recipient fails to appeal as indicated below.

C. Compliance with Statutes and Regulations - Nothing in this permit shall be construed as relieving the permittee 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. Construction Commencement - Construction must begin within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall be revoked.

H. Permit Fees - Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, the continuing validity of this permit is conditional upon the payment by the permittee of an annual operation fee, as required by that section and rules adopted thereunder by the Board.

ATTACHMENT C

FUEL GAS FLOWMETER CALIBRATION AND QUALITY ASSURANCE PROCEDURES FOR #10 BOILER

1. Use the procedures in the following standards for flowmeter calibration or flowmeter design, as appropriate to the type of flowmeter:

   ASME MFC-4M-1986 (Reaffirmed 1990), "Measurement of Gas Flow by Turbine Meters."

   American Gas Association Report No. 3, "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 1: General Equations and Uncertainty Guidelines" (October 1990 Edition), Part 2: "Specification and Installation Requirements" (February 1991 Edition) and Part 3: "Natural Gas Applications" (August 1992 edition), (excluding the modified flow-calculation method in Part 3).

   ASME MFC-7M-1987 (Reaffirmed 1992), "Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles."

2. The Department may also approve other procedures that use equipment traceable to National Institute of Standards and Technology (NIST) standards. Document other procedures, the equipment used, and the accuracy of the procedures in the monitoring plan. If the flowmeter accuracy exceeds 2.0 percent of the upper range value, the flowmeter does not qualify for use.

3. Alternatively, a fuel flowmeter used for the purposes of this part may be calibrated or recalibrated at least annually by comparing the measured flow of a flowmeter to the measured flow from another flowmeter that has been calibrated or recalibrated during the previous 365 days using a standard listed in item 1 or 2 of this Attachment. Any secondary elements, such as pressure and temperature transmitters, must be calibrated immediately prior to the comparison. Perform the comparison over a period of no more than seven consecutive unit operating days. Compare the average of three fuel-flow readings for each meter at each of three different flow levels, corresponding to (1) normal full operating load, (2) normal minimum operating load, and (3) a load point approximately equally spaced between the full and minimum operating loads. Calculate the flow meter accuracy at each of the three flow levels using the following equation:

   $$ACC = (R - A)/URV * 100$$

   Where:
   ACC =Flow meter accuracy as a percentage of the upper range value.
   R =Average of the three flow measurements of the reference flow meter.
   A =Average of the three measurements of the flow meter being tested.
   URV =Upper range value of fuel flow meter being tested (i.e., maximum measurable flow).

4. If the flow meter accuracy exceeds 2.0 percent of the upper range value at any of the three flow levels, either recalibrate the flow meter until the accuracy is within the performance specification, or replace the flow meter with another one that is within the performance specification. Notwithstanding the requirement for annual calibration of the reference flowmeter, if a reference flowmeter and the flowmeter being tested are within 1.0 percent of the flow rate of each other during all in-place calibrations in a calendar year, then the reference flowmeter does not need to be calibrated before the next in-place calibration. This exception to calibration requirements for the reference flowmeter may be extended for periods up to five calendar years.

5. Recalibrate each fuel flowmeter to a flowmeter accuracy of 2.0 percent of the upper range value prior to use under this part at least annually, or more frequently if required by manufacturer specifications. Perform the recalibration using the procedures in item 1 of this Attachment.

6. For orifice-, nozzle-, and venturi-type flowmeters, also recalibrate the flowmeter the following calendar quarter using the procedures in item 7 of this Attachment, whenever the fuel flowmeter accuracy during a calibration or test is greater than 1.0 percent of the upper range value, or whenever a visual inspection of the orifice, nozzle, or venturi identifies corrosion since the previous visual inspection.

7. For orifice-, nozzle-, and venturi-type flowmeters that are designed according to the standards in item 1 of this Attachment, satisfies the calibration requirements of this Attachment by calibrating the differential pressure transmitter or transducer, static pressure transmitter or transducer, and temperature transmitter or transducer, as applicable, using equipment that has a current certificate of traceability to NIST standards. In addition, conduct a visual inspection of the orifice, nozzle, or venturi at least annually.

8. Other procedures, standards, or methods may be substituted upon approval from the Department.

Permit Analysis
CHS Inc. – Laurel Refinery
Permit #1821-13

I. Introduction/Process Description

A. Site Location/Description

The CHS Inc. (CHS) Laurel Refinery is a petroleum refinery located in the S½ 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 vacuum heater, #2 crude heater, #2 vacuum heater, Alky hot oil heater, platformer charge heater, platformer debutanizer heater, Fluid Catalytic Cracking (FCC) feed preheater, #1 naphtha unifier (NU) charge heater, NU splitter heater, #1 NU stripper heater, #2 NU heater, #1 road oil/asphalt loading heater, #2 road oil heater, 60 tank heater, #1 fuel can heater, #5 boiler, #9 boiler, carbon monoxide (CO) boiler, Ultra Low Sulfur Diesel (ULSD) Unit Reactor charge heater, H-901, ULSD Unit Fractionation heater, H-902, Hydrogen Plant Reformer heater, H-1001, Naphtha Hydrotreater (NHT) Charge Heater, Coker Charge Heater, and Replacement Boiler #11;

2. Fuel oil fired external combustion source: #5 Boiler;

3. Gas fired internal combustion source: Platformer recycle turbine;

4. #10 Boiler;

5. Zone D combustion sources: H-101, H-201, H-202, C-201B;

6. Fugitive equipment leaks include all equipment, as defined in 40 CFR 60, Subpart VV, in hydrocarbon service;

7. FCC unit (FCCU);

8. Zone A Sulfur Recovery Unit (SRU) Tail Gas Incinerator (TGI, SRU-AUX-4) Stack source type includes: #1 SRU, #2 SRU Tail Gas Treatment Unit (TGTU);

9. Zone D SRU Incinerator;

10. Wastewater source type includes: old American Petroleum Institute (API) separator, Zone D API separator, ULSD Unit Wastewater, TGTU Wastewater;

11. Cooling tower sources: #1 cooling tower (CT), #2 CT, #3 CT, #5 CT, and #6 CT;

13. 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;

14. 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, B-1, B-2, B-7, firetk 2, firetk 3, firetk 4, TGTU-VSSL-6, and coker sludge storage tank; and

15. Delayed Coker Unit: SRU/TGTU/TGI

B. Permit History

On May 11, 1992, Cenex Harvest States Cooperatives (Cenex) was issued **Permit #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_2) emission reductions were 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 for SO_2 and nitrogen oxides (NO_x). The application referred to significant SO_2 emission reductions, which were expected by addition of the HDS project. These anticipated major SO_2 reductions were not committed to by Cenex under federally enforceable permit conditions and limitations. The contemporaneous emissions decrease for SO_2 and NO_x, 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.

Permit #1821-02 was issued on February 1, 1997, to authorize the installation of an additional boiler (#10 Boiler) 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 has 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 Section IV of the permit analysis for Permit #1821-02. Modeling performed has shown that the emission increase will not result in a significant impact to the ambient air quality (see Section VI of the permit analysis).

Cenex has also requested a permit alteration to remove the SO_2 emission limits (Section II.E.2.a of Permit #1821-01) 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_2 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. Permit #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.

This Permit #1821-02 was written to maintain the language from the HDS Complex Permit #1821-01, where possible, and to separate the HDS Complex Permit #1821-01 requirements from the requirements for the current action (boiler #10). The permit requirements from Permit #1821-01 have been included in Permit #1821-02.

On June 4, 1997, Cenex was issued **Permit #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_2	291.36 lb/day	341.04 lb/day
	NO_x	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_x	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_2	0.53 ton/yr	4.93 ton/yr
		0.135 lb/hr	1.24 lb/hr
	NO_x	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_2	0.214 lb/hr	1.716 lb/hr
		0.79 ton/yr	6.83 ton/yr
	NO_x	9.24 ton/yr	11.56 ton/yr
		2.11 lb/hr	2.90 lb/hr
H-201 (cont.)	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_2	0.128 lb/hr	2.15 lb/hr
		0.48 ton/yr	3.35 ton/yr
	NO_x	6.16 lb/hr	6.78 lb/hr
	VOC	0.24 ton/yr	0.35 ton/yr
Old Sour Water Stripper	SO_2	304.2 ton/yr	290.9 ton/yr
	NO_x	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_x and SO_2 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_x and SO_2 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_2 and NO_x 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 PM_{10} 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_{10} 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_2 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 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_2 or NO_x 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 in Section II.D.2 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 of Section II.G.5 and the reporting requirements of Section II.H.1.d were also changed to reflect this requirement.

The CO emission limits for H-201 in Section II.D.6 have been revised; the old limits were inadvertently left in the PD. The table in Section I.B of the analysis has also been changed to reflect this.

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.

Permit #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 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_x 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 Air and Waste Management Bureau (AWMB) identified the following hazardous air pollutants 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 Trimethlypentane
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 hazardous air pollutants identified above, demonstrated compliance with the negligible risk requirement.

Permit #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_2, NO_x, CO, particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), and particulate matter (PM) minus 0.1 ton per year (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_2	April 1998-March 2000	2940.4	40	2980.3
NO_x	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_{10}	April 1998-March 2000	137.3	15	152.2
PM	April 1998-March 2000	137.3	25	162.2

For example, the SO_2 annual emissions cap was calculated as follows:

Average refinery-wide SO_2 emissions in the period of April 1998 through 2000 added to the PSD/NAA significance level for SO_2 minus 0.1 TPY =

2940.4 TPY + 40 TPY – 0.1 TPY = 2980.3 TPY = Annual emissions cap.

Permit #1821-05 replaced Permit #1821-04.

Permit #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_2 below 40 tons. Permit #1821-06 replaced Permit #1821-05.

Permit #1821-07 was issued on August 28, 2001, to change the wording in Section VII.A.2, 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 (ARM 17.8.315), to correct conditions improperly referencing the incinerator rule (ARM 17.8.316), and to update a testing frequency on the product loading rack VCU based on the Title V permit term. Permit #1821-07 replaced Permit #1821-06.

On June 3, 2002, the Department received a request from Cenex to modify Permit #1821-07 to remove all references to 8 temporary, portable electricity generators. The generators were permitted under Permit #1821-06, with further clarification added in Permit #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. **Permit #1821-08** replaced Permit #1821-07.

On March 13, 2003, the Department received a complete Montana Air Quality Permit Application from Cenex to modify Permit #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. **Permit #1821-09** replaced Permit #1821-08.

On July 30, 2003, the Department received a complete Montana Air Quality Permit Application from CHS to modify Permit #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_2 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. **Permit #1821-10** replaced Permit #1821-09.

On June 1, 2004, the Department received two Montana Air Quality Permit Applications from CHS to modify Permit #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 (Permit #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. **Permit #1821-11** replaced Permit #1821-10.

On December 15, 2004, the Department received a letter from CHS to amend Permit #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. **Permit #1821-12** replaced Permit #1821-11.

C. Current Permit Action

On December 19, 2005, the Department received a complete application from CHS to build a new 15,000-barrel per day (BPD) delayed coker unit and associated equipment. The new delayed coker unit would allow 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 will be 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 would also produce 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 are subject to the requirements of 75-2-215, MCA and ARM 17.8.770, Additional Requirements for Incinerators. The analysis for those requirements is included in this permit action. **Permit #1821-13** replaces Permit #1821-12.

D. Process Description

HDS Complex - CHS has constructed a new desulfurization complex within the existing refinery to desulfurize the gas-oil streams from the crude, vacuum, and the propane deasphalting units. 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 project includes other new 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. Flow diagrams for the FCC feed desulfurizer complex and proposed refinery flow scheme were submitted as part of the HDS complex permit application.

CHS filed a petition for declaratory judgement, 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_2), CO, carbon dioxide (CO_2), and methane (CH_4). The CO is converted to CO_2 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 being 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).

The new natural gas-fired compressor engine (C-201B) is utilized by the make-up/recycle gas section of the HDS unit. Two combined compressors operate in parallel at 50% of design duty or at 2/3 of machine design capacity. Each compressor is designed for 75% of the design process duty. The gas-fired engine is a 2000-HP (horsepower) rated unit. For purposes of the application, pollutant emission rates are based on normal operating load of 1060 HP (7918 scf/hr). The compressor engine will not fire refinery fuel gas; instead, natural gas will be burned with propane as a contingency fuel.

Amine Unit - A solution of amine (nitrogen-containing organic compounds) in water removes H_2S 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_2S 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_2S and NH_3 from the water. The stripper overhead gas containing H_2S and NH_3 is sent to the new SRU for sulfur recovery and incineration of NH_3.

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_2S) to SO_2, to form water vapor and elemental sulfur. SO_2 further reacts with H_2S 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_2S-SO_2 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 is designed to process approximately 21,000 bpd 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 will shut down the existing MDU and replace it with the ULSD Unit to produce ultra low sulfur diesel and other fuels. The ULSD Unit will use the existing MDU process feeds 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 will be processed into several product streams; finished diesel, finished #1 burner fuel, and raw naphtha. These products will be stored in existing tanks dedicated to similar products from the MDU. Seven storage tanks will be modified as a result of the ULSD Unit project.

CHS's existing Hydrogen Plant and the proposed Hydrogen Plant will 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 will 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_2S 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_2S and SO_2 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_2S 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_2 in the tail gas to H_2S. After passing through the quench tower, the stream enters an amine absorber where H_2S is selectively absorbed. The off-gas passes to the SRU-AUX-4, where it is incinerated to convert remaining H_2S to SO_2 before venting to atmosphere. The rich amine leaving the absorber is regenerated in the tail gas regenerator, and the H_2S 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_2S 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 139.0 MMBtu-high heating value (HHV)/hr Coker Charge Heater, 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 Coker SRU/TGTU/TGI, which is designed to process 70.6 long tons per day of sulfur.

E. 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 four hours.

5. ARM 17.8.111 Circumvention. No person shall cause or permit the installation or use of any device or any means which, without resulting in reduction in the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant which would otherwise violate an air pollution control regulation. No equipment that may produce emissions shall be operated or maintained in such a manner that a public nuisance is created.

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

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 17.8.221 Ambient Air Quality Standard for Visibility
8. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

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 17.8.322 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.

3. 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 Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units applies to the #10 Boiler.

   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 Heater (H-101), 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 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 Stack (H-101), refinery fuel gas supply lines to the #10 Boiler, the fugitive ULSD Unit and Hydrogen Plant fugitive piping equipment, the Zone A TGTU fugitive piping equipment in VOC service, and any other applicable equipment constructed or modified after January 4, 1983.

   e. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to the HDS Complex, but not be limited to, 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 Stack (H-101), the ULSD Unit and Hydrogen Plant wastewater streams, the Zone A TGTU process drains, and any other applicable equipment. NSPS Subpart QQQ does not apply to boiler #10, since the boiler drains will not contain any oily wastewater.

4. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as listed below:

   a. Subpart A - General Provisions applies to all NESHAP source categories subject to a Subpart as listed below.

   b. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries shall apply to, but not be limited to, the Product Loading Rack and tank 96 when it is brought into gasoline service.

c. Subpart UUU – MACT Standard for Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

d. Subpart DDDDD – Industrial Boilers and Process Heaters shall apply to, (as applicable after promulgation), but not limited to, the Reactor Charge Heater (H-901), the Fractionation Heater (H-902), and the H_2 Reformer Heater (H-1001).

D. ARM 17.8, Subchapter 4 – Stack Height and Dispersion Techniques, including but not limited to:

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. CHS must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP).

E. ARM 17.8, Subchapter 5 – Air Quality Permit Application, Operation, and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. CHS submitted the appropriate permit application fee for the current permit action.

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; and the air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

   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 which 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 alteration to construct, alter, 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_2, NO_x, 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, alteration, or use of a source. CHS submitted the required permit application for the current permit action. (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 October 16, 2005, issue of the *Billings Gazette*, a newspaper of general circulation in the town 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 altered 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_2, NO_x, CO, and VOCs).
   The Delayed Coker project (including the other elements as described in the current permit action) will 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 are as follows:

Constituent	Total Project PTE (ton/yr)	Contemporaneous Emission Changes (ton/yr)	Net Emissions Change (ton/yr)	PSD Significance Level (ton/yr)
NO_x	39.2	-7.5	31.8	40
VOC	-1.5	-53.3	-54.8	40
CO	106.7	-23.2	83.5	100
SO_2	39.7	0.0	39.7	40
PM	7.6	6.6	14.2	25
PM_{10}	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).

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 the increase in emissions is less than significance levels. 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_{10} in a serious PM_{10} 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 Air Quality Permit #1821-13 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_{10} nonattainment area.

d. This facility is subject to NSPS requirements (40 CFR 60, Subparts A, Dc, J, GGG, and QQQ).

e. This facility is subject to current NESHAP standards (40 CFR 61, Subpart FF and 40 CFR 63, Subparts R, CC, UUU, and DDDDD).

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. CHS' Title V Operating Permit was issued final and effective on November 11, 2001. Further, the current permit action constitutes a significant modification to the existing Title V Operating Permit; therefore, in accordance with ARM 17.8.1227, CHS Inc. submitted a Title V permit application for this project concurrent with the Montana Air Quality permit application.

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.

For Permit #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, Permit #1821-04

Chemical Compound	Hourly Conc µg/m3	Cancer ELCR Chronic	Non-Cancer Hazard Quotient 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 µg/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 $3.9*10^{-7}$. Therefore, the Department determined that the health risk assessment model demonstrated negligible risk to public health in this case.

For Permit #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, Permit #1821-13

Chemical Compound	Modeled Conc. µg/m^3	Table 1* Conc.1 µg/m^3	Table 2* Conc. µg/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 x 10^{-6}. The RBC concentration for benzene is listed as 2.3 x 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.

Also for Permit #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, Permit #1821-13

Chemical Compound	Modeled Conc. µg/m^3	Table 1* Conc.1 µg/m^3	Table 2* Conc. µg/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. Therefore, the Department determined that the health risk assessment model demonstrated negligible risk to public health in this case.

III. BACT Determination

A BACT determination is required for each new or altered source. CHS shall install on the new or altered source the maximum air pollution control capability, which is technically practicable and economically feasible, except that BACT shall be utilized. A BACT analysis was submitted by CHS in Permit Application #1821-13 for the following operations (that include individual emitting units) subject to BACT: combustion units, tanks, wastewater emissions, fugitive emissions, coke processing, Coker Unit SRU/TGTU/TGI system, railcar light product loading and VCU, FCC, and cooling tower. The Department reviewed CHS' analysis as well as previous BACT determinations.

A. Combustion units (including the NHT Charge Heater, Coker Charge Heater, Replacement Boiler No. 11)

1. NO_x emissions

Currently, the most prevalent combustion control techniques used to reduce NO_x emissions from gas-fired boilers are flue gas recirculation (FGR), low NO_x burners (LNB) and ultra low NO_x burners (ULNB), selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR), some of which can be used in combination with each other.

SNCR is considered technically infeasible because of the temperature zone requirements for SNCR to be effective (in general 1,600-1,900 °F). The heater and boiler exhaust temperatures will be below the acceptable range. Therefore, exhaust heating systems and large energy expenditures would be necessary to allow proper abatement system operation. Therefore, SNCR will not be analyzed further. The other options are all technically feasible for the NHT Charge Heater, Coker Charge Heater, and Replacement Boiler No. 11.

Control Technology	Nominal NO_x Performance (lb/MMBtu-HHV)
ULNB + SCR	0.005
ULNB + FGR	0.02
ULNB	0.04
LNB	0.08
Conventional Burner	0.20

ULNB technology for certain applications can achieve NO_x performance less than 0.04 lb/MMBtu-HHV. However, because of many variables, including high operating temperatures, fuel quality, and heater configuration, ULNB vendors are not willing to guarantee NO_x performance less than 0.04 lb/MMBtu-HHV for these three refinery fuel gas (RFG)-fired applications. The specific reason for each application is discussed below.

FGR in conjunction with ULNB can lower NO_x emissions down to 0.02 lb/MMBtu-HHV. However, the ULNB + FGR option is only technically feasible on the Replacement Boiler No. 11. The mechanical configuration and other design aspects of the two heaters (natural draft) make the ULNB + FGR option technically infeasible for these units.

NO_x BACT for the Replacement Boiler No. 11

The top technology, SCR, was shown to have an incremental cost-effectiveness of going from ULNB + FGR to SCR of $45,577 per ton of NO_x removed (an additional 11.6 tons of NO_x removed with SCR). The Department determined that SCR was not economically feasible and, therefore, did not constitute, BACT.

Burner manufacturers indicate that a NO_x performance level of 0.04 lb NO_x/MMBtu-HHV from ULNB alone is technically achievable for the Replacement Boiler No. 11. A lower NO_x performance level from ULNB alone is not technically achievable primarily as a result of fuel quality. Also, the use of FGR in conjunction with ULNB is technically feasible because the boiler includes a forced draft fan. This combined technology can achieve an overall NO_x performance level of 0.02 lb/MMBtu-HHV.

The Department has determined that ULNB + FGR with a NO_x emissions limitation of 3.79 lb/hr (based on 0.02 lb/MMBtu-HHV) constitutes NO_x BACT for the Replacement Boiler No. 11.

NO_x BACT for the Retrofit NHT Charge Heater

Burner manufacturers indicate than a NO_x performance level of 0.04 lb NO_x/MMBtu-HHV is technically achievable for the retrofitted NHT Charge Heater. A lower NO_x performance level is not technically achievable for this heater for two primary reasons, specifically refinery fuel gas quality and reduced efficiency as a result of heater age. The heater will combust Zone A refinery fuel gas. This fuel contains a significant amount of hydrogen (20-30%). This high level of hydrogen results in a higher flame temperature and an increase in thermal NO_x production. Additionally, this heater was recently shutdown as part of the ULSD project and will be retrofit and restarted as the NHT Charge Heater. The heater was originally constructed in 1970. To achieve optimum NO_x emission rates it is important that the excess oxygen in the heater be controlled. The higher the excess oxygen, the higher the NO_x emissions will be. It should be noted, however, that there are safety issues associated with not maintaining a high enough excess oxygen level. Because of the age of the heater, it is difficult to precisely control the excess oxygen because the heater is not air-tight. For this reason, the heater will be required to operate at an excess oxygen level that has a built in safety factor.

The ULNB option was the proposed NO_x BACT for the NHT Charge Heater. As mentioned above, the ULNB+FGR option is technically infeasible for this natural draft heater and therefore has been eliminated from consideration. The top technology, SCR, was shown to have an incremental cost-effectiveness of going from ULNB to SCR of $79,428 per ton of NO_x removed (an additional 2 tons of NO_x removed with SCR). The Department determined that SCR was not economically feasible and, therefore, did not constitute, BACT. The Department has determined that ULNB with a NO_x emissions limitation of 0.57 lb/hr (based on 0.04 lb/MMBtu-HHV) constitutes NO_x BACT for the NHT Charge Heater.

NO_x BACT for the Coker Charge Heater

Burner manufacturers indicate than a NO_x performance level of 0.04 lb NO_x/MMBtu is technically achievable for the new Coker Charge Heater. A lower NO_x performance level is not technically achievable for this heater for two primary reasons, specifically refinery fuel gas quality and elevated bridge temperatures. The heater will combust refinery fuel gas from the coker unit. This fuel is expected to be similar to Zone A refinery fuel gas and contain a significant amount of hydrogen (20-30%). This high level of hydrogen results in a higher flame temperature and an increase in thermal NO_x production. Additionally, the design of the coker unit requires that this heater operate with high bridgewall temperatures. For optimum emissions control, the ideal bridge wall temperature is between 1,200 and 1,400°F. If the temperature is below this range, CO emissions can increase as a result of incomplete combustion. Above 1,400°F, the increase in production thermal NO_x becomes a factor. The bridgewall temperature of the new coker heater is expected to be between 1,500 and 1,600°F.

The ULNB option was the proposed NO_x BACT for the Coker Charge Heater. As mentioned above, the ULNB+FGR option is technically infeasible for this natural draft heater and therefore has been eliminated from consideration. The top technology, SCR, was shown to have an incremental cost-effectiveness of going from ULNB to SCR of $53,949 per ton of NO_x removed (an additional 8.5 tons of NO_x removed with SCR). The Department determined that SCR was not economically feasible and, therefore, did not constitute, BACT. The Department has determined that ULNB with a NO_x emissions limitation of 5.6 lb/hr (based on 0.04 lb/MMBtu-HHV) constitutes NO_x BACT for the Coker Charge Heater.

2. CO Emissions

   In an ideal combustion process, all of the carbon and hydrogen contained within the fuel are oxidized to carbon dioxide (CO_2) and water (H_2O). The emission of CO in a combustion process is the result of incomplete organic fuel combustion. Generally accepted CO controls for heaters are good combustion techniques. Since NO_x emissions typically increase as CO decreases, there is a balance to be maintained if add-on controls are used. The Industrial Boilers and Process Heaters MACT rule (40 CFR 63, Subpart DDDDD) states that for new liquid fuel-fired and new gas-fired boiler/heaters, the CO content should be equal to of less than 400 ppmv. The CO emissions estimates for the Replacement Boiler No. 11 and the NHT Charge Heater are based on AP-42 factors (which in turn were developed based on firing natural gas with a flue gas CO concentration of 100 ppm_{vd} @ 3% O_2). Reduction of CO can be accomplished by controlling the combustion temperature, residence time, and available oxygen. Normal combustion practice at the CHS Inc. facility 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 formation. Based on this information, CHS proposed and the Department concurs that proper design and good combustion techniques constitute CO BACT for all three RFG-fired sources.

3. VOC emissions

   VOC emissions closely track CO emissions, since an increase in CO generally indicates incomplete combustion and an increase in VOC emissions. As is consistent with similar recently permitted sources, CHS proposed and the Department concurs that proper design and good combustion techniques constitute VOC BACT for all three RFG-fired sources.

4. SO_2 emissions

   BACT emissions estimates in this permit action for SO_2 are based on an annual average H_2S content of 80.9 ppmv, which is half of the 40 CFR 60, Subpart J limit for RFG. CHS will be using relatively sweet refinery fuel gas that will have an annual average sulfur content of 80.9 ppmv. An alternative to firing the available refinery fuel gas is to fire purchased natural gas. The calculated cost of natural gas per ton of SO_2 reduced as a result is approximately $2 million per ton, based on a natural gas price of approximately $10 per MMBtu, which is economically infeasible. CHS proposed and the Department concurs that use of refinery fuel gas constitutes SO_2 BACT for all three RFG-fired sources.

5. PM/PM_{10} emissions

   Because of the relatively small amount of PM emissions produced by the Replacement Boiler No. 11, the NHT Charge Heater, and the Coker Charge Heaters, add-on control would be cost prohibitive. Thus, the Department determined that no additional control would constitute BACT for PM. The control options selected have control and control costs similar to other recently permitted similar sources and are capable of achieving the appropriate emissions standards.

B. Coker unit flare

The new coker unit flare will be used exclusively as a safety flare to control emissions during start-up, shut-down, and malfunctions (no continuous or routine vents will be flared). To meet BACT, the Department has determined this unit will have a continuous flare pilot flame and a continuous flare pilot flame monitoring device. The coker unit flare will be subject to reporting requirements under ARM 17.8.110 – the Malfunction Rule as well as reporting requirements that currently exist in the 1998 CHS Stipulation.

C. Tanks

Two new storage tanks will be added as a result of this project. The first tank will be a 50,000-barrel (bbl) Sour Water Storage Tank and the second tank will be a 40,000-gallon (gal) Coker Sludge Storage Tank. The VOC vapor pressures in both of these tanks will be less than 0.1 pounds per square inch (psia), which is much lower than any vapor pressure applicability threshold in the 40 CFR 60, Subpart K series. Therefore, NSPS does not apply to these tanks.

CHS proposed an internal floating roof (IFR) design and a submerged fill pipe for VOC control on the Sour Water Storage Tank. The IFR would limit H_2S emissions from the sour water, and a diesel-type layer would float on top of the sour water. CHS proposed a fixed roof design, a submerged fill pipe, and a conservation vent for VOC control on the Coker Sludge Storage Tank. Coker sludge has a vapor pressure less than No. 6 oil. The VOC emissions from these tanks would be less than 0.5 tons per year with the controls CHS proposed. The Department concurs that an IFR and submerged fill pipe for the Sour Water Storage Tank and a fixed roof design, submerged fill pipe, and conservation vent for the Coker Sludge Storage Tank constitutes BACT for these emitting sources and is consistent with other similar, recently permitted sources.

D. Wastewater emissions

The delayed coker unit and the other capital projects associated with this permit action will include new process drains and junction boxes in a new Coker Oily Water Sewer. This will also add additional 30 gallons per minute (gpm) of loading to the existing Wastewater Treatment Plant. Currently, CHS has two separate process sewer systems, on which is deemed compliant with 40 CFR 60, Subpart QQQ and another which is not subject to 40 CFR 60, Subpart QQQ.

CHS proposed that all of the new or modified drains associated with this permit action would be routed to the sewer systems that is 40 CFR 60, Subpart QQQ compliant, and all such drains will be treated as subject to 40 CFR 60, Subpart QQQ requirements. All new junction boxes constructed as part of the capital projects described in this permit action will be water-sealed and/or equipped with vent pipes that meet the control requirements of the NSPS. The Department concurs with CHS' proposal to route all new or modified drains to the sewer system that is 40 CFR 60, Subpart QQQ compliant and to have all such drains and junction boxes comply with the requirements of 40 CFR 60, Subpart QQQ. The Department determined such measures constitute BACT.

E. Fugitive emissions

As part of the proposed delayed coker project and the other projects described in this permitting action, new pumps, valves, flanges, and other equipment will be placed in service, while other existing equipment in certain process units will be taken out of service. CHS proposed that new equipment in VOC service will be subject to 40 CFR 60, Subpart GGG and will be included in the refinery's existing Leak Detection and Repair (LDAR) program. Under 40 CFR 60, Subpart GGG, affected facilities are required to comply with the LDAR requirements contained in 40 CFR 60, Subpart VV. CHS currently uses an 40 CFR 60, Subpart VV LDAR program for equipment throughout the refinery subject to the Refinery MACT of 40 CFR 60, Subpart GGG. The fugitive equipment in VOC service within the new coker unit and other affect units will be incorporated into the existing LDAR program, including periodic monitoring. The refinery's LDAR program also incorporates requirements contained in the Consent Decree. The Department concurs that any new pumps, valves, flanges, and other applicable equipment would be subject to 40 CFR 60, Subpart GGG and should be included in the refinery's LDAR program. This type of regulation and control constitutes BACT and is similar to requirements for other recently permitted sources.

F. Coke processing operations

For coke storage, available methods of controlling particulate emissions include enclosed storage, walled enclosures, wind fences, and wetting methods. With respect to totally enclosed storage, such as the use of silos or a storage barn, there are technical issues which make this type of operation unattractive for CHS' purposes and operation, if not totally infeasible. Normally such systems are employed when the coke is intentionally handled dry and it is advantageous for the coke to be kept as dry as possible. For example, if coke is used as a boiler fuel, more energy is recovered from the coke if it is fed to the coke boiler in as dry a state as possible. CHS would face a number of serious technical challenges if it attempted to handle the coke in enclosed structures after it is removed from the coking drum with a water cannon. CHS acquired information regarding cost if an enclosed coke storage unit were required. A similar facility for coke storage (for a coke boiler, which would require dry storage) would be between $700,000 and $800,000 without any ancillary equipment for two 1,000-ton storage silos. That would not include any baghouses, steam tracing, etc., would not consider the cost incurred due to expected operational problems that would be caused by storing wet coke in an enclosed structure, and does not include any operating cost, only construction costs. At $750,000, that would equate to approximately $46,875 per ton of PM controlled above the PM controlled with the walled enclosure proposed by CHS. The Department concurs that such a storage method would be economically infeasible and have technical feasibility issues as well. CHS proposed an enclosed coke handling area, built with a concrete floor and walls. The enclosure wall adjacent to the coke drums would be approximately 38 feet (ft) in height. The enclosure wall would then step down to a 20 ft height, which would be the final height of the other walls. An opening adjacent to the railroad track would allow access by heavy equipment such as front-end loaders to transport the coke to the crusher. The enclosed area would be sized to store more than the estimated two-day supply and allow the top of the pile to near the height of the surrounding walls.

While in storage, the coke would be wet from the cutting process and would be kept wet by operators employing hoses or a sprinkler system, as needed. However, because of the limited pile residence time (less than 2 days), it is expected that the coke would remain wetted all the way through the railcar loading process without adding additional water. This pile would be small enough that, if wetting becomes necessary, it would be able to be accomplished with fire hoses or standard sprinkler systems. The biggest technical challenge is not having the pile dry out, but is having the pile or water runoff from the pile freeze prior to or during the railcar loading process. The cold climate in Laurel makes coke freezing a significant technical problem that would be exacerbated should totally enclosed structures be used for coke storage.

Based on information provided by the CHS and other recently permitted similar sources, the Department has determined that for coke storage and processing PM/PM10 BACT is the following: a walled enclosure for coke storage, wet handling of the coke, covered conveyors, covered drop points (with minimal drop heights), covered crushers, and a telescopic loading spout into the railcars. In addition, coke storage will only be allowed in the walled enclosure.

Commenters requested that the rail load-out area be enclosed as well. However, the Department believes the appropriate controls have been required (covered conveyors, drop points, a telescopic loading spout, maintaining wet coke) that should make such an enclosure unnecessary. The system that CHS has proposed and that the Department is requiring is designed to minimize dust emissions from the transfer of coke from the crusher conveyor system into the railcars. Simply put, the coke will not be dropped from a fixed point above the railcar. The loading arm will be lowered into each railcar to begin filling the car. As the level of coke in the railcar increases, the loading arm will rise. This system will minimize dust emissions from the loading process because cross winds will not contact the coke as it is loaded into the railcar.

G. Coker Unit SRU/TGTU/TGI

The new Coker Unit SRU/TGTU/TGI is rated to recover 70.6 long tons per day (LTD) of sulfur. CHS proposed that the short-term (3-hour average) SO_2 emission limit for this unit would be based on the 40 CFR 60, Subpart J limit of 250.0 ppm_{vd} @ 0% O2 and proposed that the annual average stack SO_2 limit would be 200.0 ppm_{vd}, based on design stack flow data. The Department concurs with these SO_2 limits and has determined they will constitute BACT for SO_2. Other criteria pollutants from the supplemental natural gas combustion in this unit will be controlled by good combustion practices.

The TGI constitutes an incinerator as defined under 75-2-103, MCA and subject to 75-2-215, MCA and ARM 17.7.770 – Additional Requirements for Incinerators. BACT for similar, recently permitted incinerators includes an opacity limit of 10% and a condition restricting particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO_2. Therefore, the Department has determined that the TGI will be subject to the above-mentioned BACT conditions.

H. Railcar light product loading

The railcar light product loading unit has two main emissions sources: the Railcar Light Product VCU and the Railcar Light Product Loading Fugitives. To meet BACT requirements, the new Light Products Railcar Loading Facility will be subject to 40 CFR 63, Subpart R - the Gasoline Distribution MACT (GD MACT). The GD MACT has a primary control requirement that gasoline loading must be conducted using a VCU and that VOC emissions from the VDI cannot exceed 10 milligrams per liter (mg/l) of gasoline loaded. In addition any cargo tanks that are loaded with gasoline must be vapor tight tested. This results in an overall system capture efficiency of 99%, as present in Appendix A of the Background Information Document for the GD MACT.

When leak tested cargo vessels are loaded approximately 1% of the estimated VOC emissions are uncaptured and lost as fugitives. The other 99% of locating emissions are routed to the VCU for control, where the VCU is supplementally fired with natural gas. Based on the GD MACT, the Department has determined BACT limitations for the Railcar light product loading unit include: a 99% control system capture efficiency using the VCU, a VCU NO_x limitation of 4 mg/l of gasoline loaded, a VCU VOC limitation of 10 mg/l of gasoline loaded, and a VCU CO limitation of 10 mg/l of gasoline loaded, and a requirement that any cargo tanks must be vapor tight tested.

The VCU constitutes an incinerator as defined under 75-2-103, MCA and subject to 75-2-215, MCA and ARM 17.7.770 – Additional Requirements for Incinerators. BACT for similar, recently permitted incinerators includes an opacity limit of 10% and a condition restricting particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO_2. Therefore, the Department has determined that the TGI will be subject to the above-mentioned BACT conditions.

I. FCCU

CHS proposed the following limits (pursuant to the CHS Consent Decree, unless otherwise noted) as BACT limits:
PM = 1.0 lb PM/ 1000 lb coke burned (40 CFR 60, Subpart J limit)
VOC = 220 lb/ Mbbl of FCC feed processed (emission factor from AP-42)
CO = 150 ppm_{vd} @ 0% O_2 (annual average)
CO = 500 ppm_{vd} @ 0% O_2 (1-hr average)
NO_x = 90 ppm_{vd} @ 0% O_2 (annual average). Note that this concentration is the basis for the annual NO_x mass emission limit, but is not itself an enforceable concentration limit. (limit based on Texas Commission on Environmental Quality Regulatory Guidance document on FCCU BACT guidelines)
SO_2 = 25 ppm_{vd} @ 0% O_2 (annual average)
SO_2 = 50 ppm_{vd} @ 0% O_2 (7-day average)

With the exception of PM, all of the emission limits listed above can be achieved with existing control systems and work practices. The Department concurs with the above listed limitations for VOC, CO, NO_x, and SO_2 BACT for the FCCU.

The expansion of the FCCU capacity triggered 40 CFR 60, Subpart J applicability for PM emission from the FCCU, and the PM emission limit above corresponds to that limit. To achieve the PM emissions limit, an additional control device would have to be added to the FCCU. In addition, the CHS Consent Decree requires that CHS complete installation and begin operation of PM control equipment that is designed to meet an emission limit of 0.50 lb PM per 1000 pounds of coke burned on a 3-hour average basis by December 31, 2009.

Therefore, for PM BACT, CHS provided an analysis of a Third Stage Separator (TSS) as well as Electrostatic Precipitator (ESP). The TSS would remove PM by adding a third stage inertial separator. Wet gas scrubbers were considered briefly, but were eliminated by CHS on the basis technical infeasibility for lack of physical room for such a scrubber near the FCCU and due to concerns over water use by the scrubber.

In the analysis provided by CHS, the TSS is assumed to achieve 1.0 lb PM/ 1000 lb coke burned, which the ESP is assumed to achieve 0.5 lb PM/ 1000 lb coke burned. Based on those limitations, the annualized cost of PM reduction achieved by the TSS would be approximately $5,800 per ton of PM controlled, while the annualized cost of PM reduction achieved by the ESP would be approximately $11,100 per ton of PM controlled. The incremental cost per ton of PM controlled between the TSS and ESP would be approximately $35,930 per ton of PM controlled. The Department has determined that a TSS or another equivalent (in control efficiency) control technology as may be approved by EPA under the CHS Consent Decree with a limit of 1.0 lb PM/ 1000 lb of coke burned constitutes BACT for PM on the FCCU.

J. Cooling Tower

The primary emissions from cooling towers are PM_{10} emissions. PM_{10} emissions are based on the total dissolved solids in the cooling water and the amount of that water that evaporates into the atmosphere. Because the cooling tower will provide direct contact between the cooling water and the air passing through the tower, some of the cooling water may become entrained in the air stream and carried out of the tower as “drift” droplets. When the drift droplets evaporate, dissolved solids can crystallize and become PM_{10} emissions.

Based on other previously permitted, similar sources, the available control technologies are drift/mist eliminators (that reduce the amount of cooling water lost to the atmosphere) and good operating practices (generally including limiting excess water and air flow). Both options are technically feasible for CHS.

The mist eliminator, as proposed by CHS, would be designed to limit mist emissions to no more than 0.002% of circulating water flow. Good operating practices would be less effective. The Department determined that a mist eliminator designed to limit mist emissions to no more than 0.002% of the circulating water flow constitutes BACT for PM_{10} emissions at the cooling tower.

IV. Emission Inventory – Permit #1821-13

Due to the complexity of the projects involved in this permitting action, the emissions are summarized in the following table. The full emission inventory is contained in Permit Application #1821-13. Follwing the emission inventory table, the PSD netting analysis is listed (also in Section II.G of this permit analysis).

Project-affected unit	**New, existing or deleted source**	**NO_x (tons/yr)**	**VOC (tons/yr)**	**CO (tons/yr)**	**SO_2 (tons/yr)**	**PM (tons/yr)**	**PM_{10} (tons/yr)**
SO2 from refinery-wide oil combustion	Existing	-7.78	-0.04	-0.71	-30.86	-1.41	-1.41
No. 2 Naphtha Unifiner Charge Heater and Reboiler	Deleted	-14.85	-0.82	-12.47	-0.04	-1.13	-1.13
Compressors 1, 2, 3, 4	Deleted	-37.58	-0.49	-26.14	-7.29	0.00	0.00
NHT Charge Heater	New	2.49	0.33	5.10	0.59	0.46	0.46
FCC Feed Preheater	Existing	7.52	0.41	6.32	0.62	0.57	0.57
FCC Process	Existing	40.33	3.48	56.96	0.00	0.00	0.00
H-201 Charge Heater	Existing	3.49	0.11	2.69	1.22	1.02	1.02
H-202 Charge Heater	Existing	3.73	0.06	2.88	1.31	1.09	1.09
E-407 and INC-401	Existing	1.04	0.08	1.23	0.01	0.11	0.11
Zone D SRU/TGTU/TGI	Existing				21.40		
PDA Asphalt Heater	Deleted	-7.79	-0.43	-6.55	-0.06	-0.59	-0.59
No. 3 Boiler	Deleted	0.00	-0.72	-10.94	-0.09	-0.99	-0.99
No. 4 Boiler	Deleted	0.00	-0.64	-9.80	-0.09	-0.89	-0.89
Zone A SRU/TGTU/TGI	Existing	0.00	0.00	0.00	-10.17	0.00	0.00
BP2 Pitch Heater	Deleted	-0.85	-0.05	-0.71	-0.01	-0.06	-0.06
Wastewater Treatment Plant	Existing		1.58				
Fugitives (Equipment Leaks)	Existing		-35.02				
Storage Tanks	Existing		2.99				
Coker Charge Heater	New	24.35	1.25	31.17	5.84	2.83	2.83
Coker Unit Flare	New	0.07	0.00	0.06	0.00	0.01	0.01
Coker SRU/TGTU/TGI	New	4.16	0.23	3.49	49.38	0.32	0.32
Coke Solids Processing	New					1.88	1.02
Coker Unit Oily Water Sewer	New		6.13				
Coker Unit Cooling Tower	New		1.1			0.39	0.39
Replacement Boiler #11	New	16.57	4.47	56.25	7.95	3.85	3.85
Railcar Light Products Loading VCU	New	4.35	6.44	7.86	0.01	0.14	0.14
Railcar Light Product Loading Fugitives	New		8.08				
TOTALS		**39.2**	**-1.5**	**106.7**	**39.7**	**7.6**	**6.7**

PSD Netting Analysis

Constituent	Total Project PTE (ton/yr)	Contemporaneous Emission Changes (ton/yr)	Net Emissions Change (ton/yr)	PSD Significance Level (ton/yr)
NO_x	39.2	-7.5	31.8	40
VOC	-1.5	-53.3	-54.8	40
CO	106.7	-23.2	83.5	100
SO_2	39.7	0.0	39.7	40
PM	7.6	6.6	14.2	25
PM_{10}	6.7	6.6	13.3	15

The contemporaneous increases and decreases come from the sum of projects that include: the alky hot oil heater low NOx burners installation (May 2002), the addition of an emergency generator (July 2002), change at the asphalt loading rack (August 2002), a rate increase at the gasoline loading rack (March 2004), and the ULSD project and changes made to the Zone A TGTU/TGI (August 2005). The 1537.1 tons per year (TPY) SO_2 emissions decrease associated with the TGTU project was not included as those emissions were deemed not creditable by the CHS Consent Decree. 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). As previously mentioned, the Delayed Coker project (including the other elements as described in the current permit action) will not cause a net emission increase greater than significant levels and, therefore, does not require an NSR analysis.

V. Existing Air Quality

The area (2.0 km) around the CHS Refinery in Laurel is federally designated as nonattainment for the SO_2 NAAQS (40 CFR 81.327). 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_{10} (respirable) standards. The Billings area is listed as not classified/attainment for the new PM_{10} standard. Ambient air quality monitoring data for SO_2 from 1981 through 1992 recorded SO_2 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_2 SIP for the Billings/Laurel area was inadequate and needed to be revised. The Department, in cooperation with the Billings/Laurel area SO_2 emitting industries, adopted a new control plan to reduce SO_2 emissions by establishing emission limits and requiring continuous emission monitors on most stacks. Area SO_2 emissions have since declined between 1992 and 1999. The decline can be attributed to industrial controls added as part of the SIP requirements, plants operating at less than full capacity, and industrial process changes to meet sulfur in fuel regulations. Ambient air quality monitoring for SO_2, PM_{10}, and CO in the Billings/Laurel area continues.

VI. Air Quality Impacts

The Department did not conduct ambient air modeling for this permit action. The Department believes the current permit action will not cause or contribute to a violation of any ambient air quality standard because emissions from this permit action will not surpass the facility-wide limits that were based on recent historical emissions, which complied with ambient air quality standards.

VII. Taking or Damaging Implication Analysis

As required by 2-10-101 through 105, MCA, the Department conducted a private property taking and damaging assessment and determined there are no taking or damaging implications.

VIII. 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
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FINAL ENVIRONMENTAL ASSESSMENT (EA)

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

Permit Number: 1821-13

Preliminary Determination on Permit Issued: January 27, 2006
Department Decision Issued: March 10, 2006
Permit Final: March 28, 2006

1. Legal Description of Site: South ½, Section 16, Township 2 South, Range 24 East in Yellowstone County.

2. Description of Project: On December 19, 2005, the Department received a complete application from CHS to build a new 15,000-barrel per day (BPD) delayed coker unit and associated equipment. The new delayed coker unit would allow 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 will be 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 would also produce 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 are subject to the requirements of 75-2-215, MCA and ARM 17.8.770, Additional Requirements for Incinerators. The analysis for those requirements is included in this permit action.

3. Objectives of Project: As mentioned above, construction and operation of the delayed coker unit would allow CHS to increase gasoline and diesel production by 10-15%, which are more profitable than the current asphalt production. In addition, the new Railcar Loading Facility would allow CHS more flexibility in transporting their products from the refinery.

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 Montana Air Quality permit 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 a BACT determination, would be contained in Permit #1821-13.

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 would result in increased NO_x, SO_2, CO, and particulate emissions. However, the emissions are within the facility-wide emissions caps established in Permit #1821-05 in 2000, and are well below the applicable State Implementation Plan SO_2 emissions caps. Impacts to terrestrial life and habitats may occur as a result of these increased emissions. Habitat impacts could result in a change of diversity or abundance of terrestrial or aquatic life. However, this area does not appear to contain any critical or unique wildlife habitat or aquatic life and the project would occur in an already disturbed area.

B. Water Quality, Quantity, and Distribution:

The actions addressed in this permit would result in a slight increase in the amount of water discharged to surface water (approximately 30 gallons per minute) following water treatment but would not change the characteristics of the water discharged from the CHS refinery. 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. Therefore, minor impacts to water quality, quantity, and/or distribution are anticipated.

C. Geology and Soil Quality, Stability, and Moisture:

No additional disturbance would be created from this action. Existing structures and equipment would be removed to make room for the new equipment. While deposition of pollutants would occur, the Department determined that any impacts from deposition of pollutants would be minor. This project would not change the soil stability or geologic substructure or result in any increased disruption, displacement, erosion, compaction, or moisture loss, which would reduce productivity or fertility at or near the site. No unique geologic or physical features would be disturbed. Therefore, minor impacts to geology and soil quality, stability, and moisture are anticipated. The issuance of the permit would not result in construction of any structures outside the area already disturbed; therefore, there would be only minor impact on the soil quantity, stability, moisture, or geology.

D. Vegetation Cover, Quantity, and Quality:

This project would be constructed on land already used for industrial activities. The vegetative cover, quantity, and quality would not be disturbed inside the facility boundaries. However, possible increases in actual emissions of NO_x, CO, SO_2, and particulate from historical emission levels may result in minor impacts to the diversity, productivity, or abundance of plant species in the surrounding areas. Issuance of this permit would cause minor if any changes in vegetation cover, quantity, or quality.

E. Aesthetics:

The proposed delayed coker unit and railcar loading facility would be visible and would create additional noise in the area. However, the proposed facilities would be constructed in the area that has previously been disturbed and already has noise associated with its operation. Members of the public have expressed concern regarding the containment of petroleum coke and coke dust associated with the proposed delayed coker unit. The Department has analyzed the particulate emissions associated with coke storage with respect to the application of BACT. The controls applied and the permit conditions that support them should minimize any disturbance from these emissions. Therefore, any additional impacts on aesthetics would be minimal.

F. Air Quality:

The project would include increases in NO_x, SO_2, CO, and particulate emissions above recent historical levels. However, the emissions are within the facility-wide emissions caps established in Permit #1821-05 in 2000, and are well below the applicable State Implementation Plan SO_2 emissions caps. However, previously modeled levels of pollutants (at allowable levels) show compliance with the National Ambient Air Quality Standards (NAAQS) and the Montana Ambient Air Quality Standards (MAAQS). The overall impact on air quality would be expected to be minor.

G. Unique Endangered, Fragile, or Limited Environmental Resources:

This permitting action may result in minor impacts to terrestrial and aquatic life and/or their habitat. However, the Department is not aware of any unique, rare, threatened, or endangered species in the area surrounding the facility. Further, 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:

This project would probably not consume any significant additional energy or water resources. However, minor upgrades of utilities may be required during the construction process. Further, 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. This action did not include an increase in allowable levels. Previous modeling efforts, using allowable levels, showed compliance with the NAAQS and the MAAQS. This project would result in a minor effect on the air resource, but resulting emissions will still comply with ambient air quality standards.

I. Historical and Archaeological Sites:

This project would not disturb a greater land surface than has already been occupied by the refinery. This project would occur within the boundaries of the area already disturbed. Therefore, no impacts to any historical and archaeological sites would be anticipated.

J. Cumulative and Secondary Impacts:

Increases in actual pollutant emissions above historical levels may result in minor cumulative and secondary impacts to terrestrial and aquatic habitats, water quality, and air quality. However, as previously mentioned, the emissions are within the facility-wide emissions caps established in Permit #1821-05 in 2000, and are well below the applicable State Implementation Plan SO_2 emissions caps. Minor cumulative or secondary impacts are expected to result from this project.

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
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 facility would not cause a disruption to any native or traditional lifestyles or communities (social structures or mores) in the area because the project would be constructed at a previously disturbed, industrial site. The proposed project would not change the nature of the site.

B. Cultural Uniqueness and Diversity:

The proposed project 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.

C. Local and State Tax Base and Tax Revenue:

This project would have a minor effect on the local and state tax base and tax revenue because the proposed addition of the delayed coker unit is intended to increase production of products more profitable than asphalt (specifically gasoline and diesel). Several new employees are expected to be added as a result of the proposed project, which may also have a minor impact on local and state tax base and tax revenue. Therefore, tax revenue from the facility might increase slightly.

D. Agricultural or Industrial Production:

The proposed project would not result in a reduction of available acreage or productivity of any agricultural land; therefore, agricultural production would not be affected. Industrial production would change slightly because the asphalt production would be reduced to produce other, higher value products, specifically gasoline and diesel.

E. Human Health:

As described in Section 7.F of the EA, the impacts from this facility on human health would be minor. The project would include increases in NO_x, SO_2, CO, and particulate emissions from recent emissions levels. However, the emissions are within the facility-wide emissions caps established in Permit #1821-05 in 2000, and are well below the applicable State Implementation Plan SO_2 emissions caps. The air quality permit for this facility incorporates 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:

This project would not have an impact on recreational or wilderness activities because the construction site is far removed from recreational and wilderness areas or access routes. This project would not result in any changes in access to and quality of recreational and wilderness activities.

G. Quantity and Distribution of Employment:

This project would result in minor impacts to the quantity and distribution of employment at the facility and surrounding community because CHS is planning on hiring several employees as a result this project. In addition, temporary construction-related positions could result from this project but any impacts to the quantity and distribution of employment would be minor.

H. Distribution of Population:

This project 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 project.

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 (including local building permits, as necessary, and a state air quality permit) and compliance verification with those permits.

J. Industrial and Commercial Activity:

Overall industrial production at the CHS refinery would not change as a result of the project, as the refinery's overall capacity would not change. However, the composition of CHS' production would change because construction and operation of the delayed coker project would potentially increase the production of gasoline and diesel by 10-15%, while reducing the production of asphalt by 75%. In addition, the construction of the rail car loading facility would allow CHS more flexibility in transporting their products, and may reduce some truck traffic to the refinery. Therefore, a minor impact on industrial activity at CHS would be expected. Industrial and commercial activity in the neighboring area is not anticipated to be affected by issuing Permit #1821-13.

K. Locally Adopted Environmental Plans and Goals:

This project would not affect any locally adopted environmental plans or goals, CHS must continue to comply with the State Implementation Plan (SIP) 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 project.

L. Cumulative and Secondary Impacts:

Increases in actual pollutant emissions of NO_x, SO_2, CO, and particulate emissions above recent historical levels may result in minor cumulative and secondary impacts to the human environment. However, the emissions are within the facility-wide emissions caps established in Permit #1821-05 in 2000, and are well below the applicable State Implementation Plan SO_2 emissions caps. Therefore, the cumulative and secondary impacts from the proposed project would be minor.

Recommendation: An 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 construction and operation of the proposed facility 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.

EA Prepared By: Debbie Skibicki
Date: January 19, 2006