DEQ
Montana Department
of Environmental Quality
Air, Energy & Mining Division

PRELIMINARY DETERMINATION
ON PERMIT APPLICATION MAQP #1821-46

Date of Posting: November 14, 2024

Name of Applicant: CHS Inc.

Source: Petroleum Refinery
Location: Laurel, Montana

Proposed Action: DEQ proposes to issue a permit, with conditions, to the above-named applicant. The application was assigned Montana Air Quality Permit (MAQP) Application Number 1821-46.

Proposed Conditions: See attached Preliminary Determination of MAQP #1821-46.

Public Comment: Any member of the public desiring to comment must submit comments to DEQ-ARMB-Admin@mt.gov or to the address below. Comments may address DEQ's analysis and Preliminary Determination, or the information submitted in the application. All comments are due by November 29, 2024. Copies of the application and DEQ's analysis may be requested at https://deq.mt.gov (at the bottom of the home page, select *Request Public Records*). For more information, you may contact DEQ at (406) 444-3490, or DEQ-ARMB-Admin@mt.gov.

Departmental Action: DEQ intends to make a Decision on the application following the Public Comment period. A copy of the Decision will be available on DEQ's website, https://deq.mt.gov/public/publicnotice (select *AIR*). The permit shall become final on the date stated in the Decision, unless the Board of Environmental Review (Board) orders a stay on the permit.

Procedures for Appeal: Any person who is directly and adversely affected by DEQ's Decision may request a hearing before the Board. The appeal must be filed by the date that will be stated in the Decision. The request for a hearing must contain an affidavit setting forth the grounds for the request. The hearing will be held under the provisions of the Montana Administrative Procedures Act. Submit requests for a hearing to: Chairman, Board of Environmental Review, P.O. Box 200901, Helena, MT 59620, or the Board Secretary: DEQBERSecretary@mt.gov.

For DEQ,

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MONTANA AIR QUALITY PERMIT

Issued to:	CHS Inc. Laurel Refinery P.O. Box 909 Laurel, MT 59044-0909	MAQP: #1821-46 Application Complete: 10/07/2024 Preliminary Determination (PD) Issued: 11/14/2024 Department Decision (DD) Issued: Permit Final:

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to CHS Inc. (CHS) pursuant to Sections 75-2-204, 211, 213, and 215, Montana Code Annotated (MCA), as amended, and the Administrative Rules of Montana (ARM) 17.8.740, *et seq*., as amended, for the following:

Section I: Permitted Facilities

A. Plant Location/Description

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

- Refinery Limitations and Conditions associated with MAQP #1821-05 (Section II)
- Fuel Gas Combustion Devices (Section III)
- Mild Hydrocracker with associated Zone D sulfur recovery unit (SRU) and tail gas treatment unit (TGTU) (Section IV)
- Boiler #10 (Section V)
- Truck Loading Rack and Vapor Combustion Unit (VCU) (Section VI)
- No. 1 Crude Unit (Section VII)
- Ultra-Low Sulfur Diesel (ULSD) Unit and Hydrogen Plant (Section VIII)
- TGTU for Zone A's SRU #1 and SRU #2 trains (Section IX)
- Fluidized Catalytic Cracking Unit (FCCU) (Section X)
- Naphtha Hydrotreater (NHT) Unit, Delayed Coker Unit, and Zone E SRU/TGTU and Tail Gas Incinerator (TGI) (Section XI)
- Boiler #11 (Section XII)
- Railcar Light Product Loading Rack and VCU and Railcar Gasoline Component Unloading (Section XIII)

- Boiler #12 (Section XIV)
- Benzene Reduction Unit (Section XV)
- Product Storage Tanks (Section XVI)
- Product Storage Tank 133 (Section XVII)
- Wastewater Facilities (Section XVIII)
- Intermediate Storage Tanks 146 and 147 (Section XIX)
- Replacement Refinery Flare / Waste Gas Control System (Section XX)
- Sour Water Stripper Ammonia Combustor (Section XXI)
- Crude Blending Project (Section XXII)
- Hydrogen Plant #3 Project (Section XXIII)
- Asphalt Storage Tanks (Section XXIV)
- Multi-Unit Expansion Project (Section XXV)
- General Conditions (Section XXVI)

B. Current Permit Action

On September 11, 2024, DEQ received an application from CHS for modification of MAQP #1821-45. In the application, CHS is proposing revisions to the Multi-Unit Expansion Project (MUE), previously approved under MAQP #1821-43. The earlier permitting action authorized changes to the existing #2 Crude Unit, Mild Hydrocracker, Delayed Coker, and Naphtha Stabilizer. Revisions within the new application propose removal of a previously proposed process heater and steam boiler, as well as the addition of modifications to the Zone A and Zone D sulfur recovery plants (SRPs). Additionally, and unrelated to the MUE original project scope or the revised MUE project scope, the new application proposes modifications for the Routine Molten Sulfur Trucking Project.

DEQ will refer to this application, proposing changes to the original MUE project, as the Revised Multi-Unit Expansion Project (RMUEP). With the scope changes, the RMUEP is no longer subject to PSD preconstruction requirements as emission increases no longer exceed applicable PSD thresholds. Previously, the MUE was subject to PSD for significant emission increases of NO_x, PM_{10} and $PM_{2.5}$. The RMUEP revisions remove the addition of the new Coker Charge Heater (H-7502), removes the addition of the proposed new Boiler 13, and no longer proposes shuttering the existing Boiler 9. The Routine Molten Sulfur Trucking Project would add the ability for permanent molten sulfur truck loading from Sulfur Recovery Plants (SRPs) in Zone D and E, and also evaluates the use of molten sulfur truck loading in Zone A as a change in the method of operation. The Routine Molten Sulfur Trucking Project is not a major modification and not subject to PSD preconstruction requirements for any pollutant.

Section II: Refinery Limitations and Conditions associated with MAQP #1821-05

With the issuance of MAQP #1821-05, CHS requested to place enforceable limits on future site-wide emissions for the collective units that were in operation at the facility. Although modifications (including removal and addition of various emitting units) have occurred at the facility since these limitations were put in place, the following units identified at the time of issuance of MAQP #1821-05 continue to be subject to the limitations and conditions within this Section:

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

    a. #1 Crude heater

    b. Crude Preheater

    c. #1 Crude Vacuum Heater

    d. #2 Crude Heater

    e. #2 Crude Vacuum Heater

    f. Alkylation Unit Hot Oil Belt Heater

    g. Platformer Heater (P-HTR-1)

    h. Platformer Debutanizer Heater

    i. FCC Feed Preheater (this heater was shut down as part of the MHC project MAQP 1821-23). A replacement heater has been permitted and constructed but is not included as part of these site-wide limits

    j. #1 Naphtha Unifiner charge heater (renamed NHT Reboiler Heater #2 – H-8303 for new service as part of coker project in 1821-13)

    k. #2 NU heater (shutdown as part of coker project – MAQP 1821-09)

    l. MDU Charge Heater (H-8301) (Shutdown as part of ULSD project = MAQP 1821-09) [Now not part of PAL]

    m. MDU Stripper Heater (Shutdown as part of ULSD project – MAQP 1821-09)

    n. PDA Heater (shutdown as part of coker project, MAQP #1821-13)

    o. #1 Road Oil/Asphalt Loading heater (asphalt loading heater #1)

    p. #2 road oil heater (removed from service and now not part of the

PAL)

q. BP2 Heater (the heater has been removed but the BP2 tank is still present)

r. 60 Tank Heater

s. #1 Fuel Can Heater (#1 fuel oil heater)

t. #3 Boiler (permanently shut down as Consent Decree project; MAQP #1821-15. Has been removed.)

u. #4 Boiler (permanently shut down as Consent Decree project; MAQP 1821-22. Has been removed.)

v. #5 Boiler (permanently shut down as Consent Decree project; MAQP 1821-22. Has been removed.)

w. #9 Boiler

x. CO Boiler (permanently shut down as Consent Decree project; MAQP 1821-15. Has been removed.)

y. #10 Boiler

z. H-101 Zone D Hydrogen Plant Reformer Heater

aa. H-201 Reactor Charge Heater

bb. H-202 Fractionator Feed Heater

cc. C-201B (Permanently shut down and replaced with electric)

dd. NU Splitter Heater (renamed NHT Splitter Reboiler H-8304, MAQP #1821-13)

ee. #1 NU Stripper Heater (renamed NHT Reboiler Heater #1 H-8302, MAQP #1821-13)

2. Fuel oil-fired external combustion sources, includes:

a. #3 Boiler (permanently shut down as Consent Decree Project; MAQP #1821-15. Has been removed.)

b. #4 Boiler (permanently shut down as Consent Decree Project; MAQP #1821-22. Has been removed.)

c. #5 Boiler (permanently shut down as Consent Decree Project: MAQP #1821-22. Has been removed.)

d. #1 crude heater (ceased burning oil)

3. Gas-fired internal combustion source, includes:

    a. Platformer recycle turbine (permanently shut down in 2018)

    b. #1-4 unifier compressors (shutdown with ULSD and coker projects)

4. FCC unit (FCCU) Regenerator

5. Zone A Sulfur Recovery Unit (SRU) Tail Gas Incinerator (TGI, SRU-INC-22)
6. Zone D SRU Incinerator

7. Fugitive equipment leaks include all equipment, as defined in 40 Code of Federal Regulations (CFR) 60, Subpart VV, in hydrocarbon service

8. Wastewater sewers, separation, and treatment facilities

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

10. Loading facilities:

    a. light product truck rack and vapor combustion unit (VCU) [excludes new facility permitted with 1821-27]

    b. heavy oil truck rack, and

    c. heavy oil rail rack.

11. Storage tanks: Tank numbers 2, 6 (demo'd), 7, 9 (Replaced with Tank 127), 12, 28 (Replaced with Tank 126), 41, 47, 56, 60, 61, 62, 63, 64 (demo'd), 65 (Replaced with Tank 144), 66, 67 (Replaced with Tank 145), 68, 70, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 85, 86, 88, 91, 92, 93, 94, 95, 96, 100, 101, 102, 103, 104, 108, 109, 110, 111, 112, 113, 114, 117, 118, 120, 121, 122, 123, B-1, B-2, B-7, BP-2, firetk 2, firetk 3, and firetk 4.

A. National Emission Standards for Hazardous Air Pollutants

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

B. Annual Emission Limitations (ARM 17.8.749):

1. SO_2 emissions shall not exceed 2,980.3 tons per year (TPY)

2. NO_x emissions shall not exceed 999.4 TPY

3. CO emissions shall not exceed 678.2 TPY

4. Volatile organic compounds (VOC) emissions shall not exceed 1,967.5 TPY

5. Particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) emissions shall not exceed 152.2 TPY

6. Particulate matter (PM) emissions shall not exceed 162.2 TPY

C. Compliance Determination (ARM 17.8.749):

CHS shall determine the CO, NO_x, and VOC emissions for combustion sources by utilizing the Plant Information (PI) system information and normalize that PI system information to the refinery yield report. CHS shall also provide the Department with the amount of fuel consumed annually in the refinery as documented in the refinery yield report. This methodology was used to determine the CO, NO_x, and VOC emissions in CHS's MAQP #1821-05 application and again in the August 12, 2004, letter from CHS to the Department.

CHS will track compliance with the emission caps based on source type, pollutant, calculation basis (emission factors, estimated yield and conversion), and key parameters (fuel oil use, fuel gas use, process gas use, and CEMS data). The units included in each source type are listed in Section I.A of the permit analysis. The calculation basis for each unit is listed in Attachment A (Refinery Limitations and Conditions associated with MAQP #1821-05 Compliance Determination).

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

D. Testing Requirements

1. Fuel flow rates, fuel heating value, production information and other data, as needed, shall be recorded during the performance of source tests in order to develop emission factors for use in the compliance determinations (ARM 17.8.749).

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

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

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. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

3. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service (or equivalent service). The report shall also include the following:

   Summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

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

5. 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

CHS shall provide the Department 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 or email whenever a malfunction occurs that can be expected to create emissions in excess of

any applicable emission limitation, or to continue for a period greater than 4 hours (ARM 17.8.110).

Section III: Limitations and Conditions for Fuel Gas Combustion Devices

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart J - Standards of Performance for Petroleum Refineries applies to all fuel gas combustion devices with the exception to those subject to NSPS Subpart Ja. Applicability of NSPS Subpart Ja to fuel gas combustion devices is identified on a source-by-source basis within the permit.

3. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.

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

C. Limitations on Fuel Gas Devices

1. For fuel gas combustion devices where construction, reconstruction, or modification commenced prior to May 14, 2007, refinery fuel gas burned in fuel combustion devices shall not exceed 0.10 grains of H_2S per dry standard cubic foot (162 parts per million, volumetric dry (ppm_{vd}) H_2S) per rolling 3-hour average. This does not apply to the Sour Water Stripper Ammonia Combustor (ARM 17.8.340, ARM 17.8.749, 40 CFR 60, Subpart J).

2. Refinery fuel gas burned in fuel combustion devices shall not exceed 0.05 grains of H_2S per dry standard cubic foot (81 ppm_{vd} H_2S) per 12-month average (ARM 17.8.340 and ARM 17.8.749).

3. For fuel gas combustion devices where construction, reconstruction, or modification commenced after May 14, 2007, CHS shall not burn any fuel gas that contains H_2S in excess of 162 ppm_{vd} determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppm_{vd} determined daily on a 365-successive calendar day rolling average basis. This does not apply to the Sour Water Stripper Ammonia Combustor (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Ja).

D. Monitoring Requirements

1. CHS shall install and operate the following Continuous Emissions Monitoring System (CEMS) / Continuous Emission Rate Monitor System (CERMS): Continuous concentration (dry basis) monitoring of H_2S in

refinery fuel gas burned in all refinery fuel gas combustion devices. This does not apply to the Sour Water Stripper Ammonia Combustor.

2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subpart J, 60.100-108, Subpart Ja, 60.100a-108a and Appendix B, Performance Specification 7 and Appendix F (Quality Assurance/Quality Control) provisions.

3. H_2S refinery fuel gas CEMS and fuel gas flow rate meters shall comply with all applicable requirements of the Billings/Laurel SO_2 State Implementation Plan (SIP) Emission Control Plan, including Exhibit A and Attachments, adopted by the Board of Environmental Review, June 12, 1998, and stipulated to by Cenex Harvest States Cooperative and its successor CHS.

4. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.

E. Compliance Determinations

1. Compliance determinations for SO_2 and H_2S limits for the fuel gas-fired units within the refinery shall be based upon CEMs data utilized for H_2S, as required in Section III.D.1 and fuel firing rates, if these units are fired on refinery fuel gas. Firing these units solely on natural gas shall demonstrate compliance with the applicable SO_2 limits. This does not apply to the Sour Water Stripper Ammonia Combustor.

2. In addition to the testing required in each section, compliance determinations for the emission limits applicable to the fuel gas shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test, and/or available CEM data. Fuel flow rates, fuel heating value, production information and other data, as needed, shall be recorded for each emitting unit during the performance of the source tests in order to develop emission factors for use in the compliance determinations. New emission factors (subject to review and approval by the Department) shall become effective within 60 days after the completion of a source test. Firing these units solely on natural gas shall demonstrate compliance with the applicable VOC limits (ARM 17.8.749).

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

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File

Transfer Service (or equivalent service). The report shall include the following:

a. summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

b. a summary report for all CEMS required by this section.

Section IV: Limitations and Conditions for the Mild Hydrocracker

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart J - Standards of Performance for Petroleum Refineries applies to the Fractionator Feed Heater Stack (H-202), the Reactor Charge Heater Stack (H-201), and the Hydrogen Reformer Heater (H-101).

3. Subpart Ja - Standards of Performance for Petroleum Refineries applies to the Hydrogen Reformer Heater (H-102) and SRU Incinerator Stack (INC-401).

4. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to the Mild Hydrocracker Unit.

5. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the Mild Hydrocracker unit.

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 - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. Applies to the Zone D SRP.

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

D. Limitations on Individual Sources

1. Zone D SRU Incinerator Stack (INC-401)

   a. CHS shall operate and maintain the TGTU on the Zone D SRU to limit SO_2 emissions from the Zone D SRU incinerator stack (INC-401) by following the below requirements:

      i. CHS shall not exceed 53.17 tons/rolling 12-calendar month total, applicable at all times except malfunction (ARM 17.8.749).

      ii. CHS shall not exceed 14.21 lb/hr (ARM 17.8.749).

      iii. CHS shall not exceed 250 ppmvd at 0% excess O_2 on an hourly rolling 12-hour average, except during periods of startup, shutdown, and malfunction (ARM 17.8.752 and 40 CFR 60, Subpart Ja).

      iv. CHS shall minimize the frequency and duration of startups and shutdowns of the Zone D SRP by operating at all times in accordance with an operation, maintenance and monitoring plan meeting the requirements of 40 CFR 63.1574(f) (ARM 17.8.752).

      v. CHS shall comply with 40 CFR 63 subpart UUU (Refinery MACT II) operating limits at 63.1568(a)(4) during periods of startup and shutdown (ARM 17.8.752).

      vi. For the purposes of startup and shutdown, shutdown means the cessation of operation of an affected source or portion of an affected source for any purpose. Startup means the setting in operation of an affected source or portion of an affected source for any purpose (40 CFR 63.2.). CHS shall document these events to define periods of startup and shutdown for the purpose of compliance demonstration (ARM 17.8.749).

   b. NO_x emissions from the Zone D SRU incinerator stack shall not exceed (ARM 17.8.749):

      i. 3.5 tons/rolling 12-calendar month total,

      ii. 19.2 lb/day, and

      iii. 0.8 lb/hr.

2. Reformer Heater Stack (H-101)

   a. SO_2 emissions from H-101 shall not exceed (ARM 17.8.749):

    i. 1.68 tons/rolling 12-calendar month total

    ii. 2.15 lb/hr

  b. NO_x emissions from H-101 shall not exceed (ARM 17.8.749):

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

  c. CO emissions from H-101 shall not exceed (ARM 17.8.749):

    i. 13.93 tons/rolling 12-calendar month total

    ii. 4.51 lb/hr

  d. VOC emissions from H-101 shall not exceed 0.35 tons/rolling 12-calendar month total (ARM 17.8.749).

3. <u>Reformer Heater Stack (H-102)</u>

  a. All available 100 Unit PSA tailgas shall be fired in the 100 Unit Hydrogen Plant reformer heaters, except during periods of startup, shutdown or process upset (ARM 17.8.752).

  b. CHS shall not burn in the H-102 Reformer Heater any fuel gas that contains H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja).

  c. NO_X emissions from H-102 shall not exceed:

    i. 40 ppmv (dry basis, corrected to 0 percent excess air) on a 30-day rolling average basis (40 CFR 60, Subpart Ja)

    ii. 3.02 lb/hr (24-hr rolling average) (ARM 17.8.752)

    iii. 11.3 tons/rolling 12-calendar month total (ARM 17.8.749)

  d. CO emissions from H-102 shall not exceed:

    i. 5.7 lb/hr (ARM 17.8.752)

    ii. 25.1 tons/rolling 12-calendar month total (ARM 17.8.749)

  e. H-102 shall be fitted with Ultra Low NOx Burners (ULNBs) (ARM 17.8.752).

  f. CHS shall implement proper design and good combustion techniques to minimize CO, VOC, and $PM/PM_{10}/PM_{2.5}$ emissions (ARM 17.8.752).

4. Reactor Charge Heater Stack (H-201)

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

      i. 4.35 tons/rolling 12-calendar month total

      ii. 1.99 lb/hr

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

      i. 11.56 tons/rolling 12-calendar month total

      ii. 2.90 lb/hr

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

      i. 8.92 tons/rolling 12-calendar month total

      ii. 2.23 lb/hr

   d. VOC Emissions from H-201 shall not exceed 0.91 tons/rolling 12-calendar month total (ARM 17.8.749).

5. Fractionator Feed Heater Stack (H-202)

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

      i. 3.14 tons/rolling 12 calendar-month total

      ii. 1.43 lb/hr

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

      i. 8.34 tons/rolling 12 calendar-month total

      ii. 2.09 lb/hr

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

      i. 6.43 tons/rolling 12-calendar month total

      ii. 1.61 lb/hr

   d. VOC emissions from H-202 shall not exceed 0.65 tons/rolling 12-calendar month total (ARM 17.8.749).

6. Molten Sulfur Truck Loading and Transport: CHS shall meet the following requirements for Zone D Molten Sulfur Truck Loading:

   a. CHS shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter. CHS shall treat unpaved molten sulfur trucking transport roads with water and/or chemical dust suppressant as necessary to control emissions while molten sulfur is being transported on roads on the refinery property (ARM 17.8.308 and ARM 17.8.752).

b. CHS shall clean the paved sections of molten sulfur transport roads, as necessary, for reasonable precautions specific to truck hauling of molten sulfur on refinery property (ARM 17.8.308 and ARM 17.8.752).

c. CHS is subject to ARM 17.8.304(2) for visible opacity limits of 20 percent for molten sulfur truck loading (ARM 17.8.304 and ARM 17.8.749).

E. Monitoring Requirements

1. CHS shall install and operate the following CEMS/CERMS for the SRU Incinerator Stack (INC-401):

   a. SO_2 (SO_2 SIP, 40 CFR 60 Subpart Ja)

   b. O_2 (40 CFR 60, Subpart Ja)

   c. Volumetric Flow Rate (SO_2 SIP)

2. CHS shall install, operate, calibrate, and maintain the following CEMS/CERMS for H-102 Reformer Heater Stack (H-102):

   a. NO_X (40 CFR 60, Subpart Ja)

   b. O_2 (40 CFR 60, Subpart Ja)

   c. Stack Flow Rate (ARM 17.8.749)

3. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, 60.100-108, Subparts Ja, 60.100a-60.108a, and Appendix B, Performance Specifications 2, 3, 6, and Appendix F; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).

4. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, and breakdowns and repairs of CEMS related equipment. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated (ARM 17.8.749).

F. Testing Requirements

1. The SRU Incinerator Stack (INC-401) shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department for SO_2 and shall be tested on an every 6-year basis, or according to another testing/monitoring schedule

as may be approved by the Department, for NOx. The results submitted to the Department in order to demonstrate compliance with the SO_2 and NO_x emission limits contained in Section IV.C.1.a, b, and c (ARM 17.8.105 and ARM 17.8.749).

2. The Reformer Heater Stack (H-101) shall be tested every three years from the date of the last source test, 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 IV.C.2.b and c (ARM 17.8.105 and ARM 17.8.749).

3. The Reformer Heater Stack (H-102) shall be tested every three years from the date of the last source test, in conjunction with annual CEMS/CERMS RATA performance testing in accordance with Appendix F (40 CFR Part 60) requirements, or according to another testing/ monitoring schedule as may be approved by the Department, for NO_x/O_2 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 IV.C.3.c and d (ARM 17.8.105 and ARM 17.8.749, 40 CFR 60, Subpart Ja).

4. The Reactor Charge Heater Stack (H-201) shall be tested every three years from the date of the last source test, 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 IV.C.4.b and c (ARM 17.8.105 and ARM 17.8.749).

5. The Fractionator Feed Heater Stack (H-202) shall be tested every three years from the date of the last source test, 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 IV.C.5.b and c (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations

1. In addition to the testing required in Section IV.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 IV.D.1.

2. Compliance with the opacity limitation listed in Section IV.C shall be determined using EPA Reference Method 9 testing by a qualified observer.

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

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall prepare and submit a quarterly emission report

within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service (or equivalent service). The report shall include the following:

a. summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

b. a summary report for all CEMS required by this section.

Section V: Limitations and Conditions for Boiler #10

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

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

3. Subpart J - Standards of Performance for Petroleum Refineries. The requirements of this Subpart apply to Boiler #10.

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

B. Emission Limitations for Boiler #10

1. SO_2 emissions shall not exceed:

a. 60 ppmv H_2S in refinery fuel gas, 365-day rolling average (ARM 17.8.752)

b. 4.14 tons/rolling 12-calendar month total (ARM 17.8.749)

c. 2.53 lb/hr (ARM 17.8.752)

2. NO_x emissions shall not exceed:

a. 0.03 pounds per million British thermal units – Higher Heating Value (lb/MMBtu-HHV), 365-day rolling average (ARM 17.8.752)

b. 13.13 tons/rolling 12-calendar month total (ARM 17.8.749)

c. 3.5 lb/hr (ARM 17.8.749)

3. During periods of startup or shutdown, CO emissions shall not exceed 10.0 lb/hr, 24-hour rolling average (ARM 17.8.752). Otherwise, CO emissions shall not exceed:

    a. 0.05 lb/MMBtu-HHV, 365-day rolling average (ARM 17.8.752)

    b. 21.88 tons/rolling 12-calendar month total (ARM 17.8.749)

    c. 5.0 lb/hr (ARM 17.8.749)

4. VOC emissions shall not exceed 2.24 tons/rolling 12-calendar month total (ARM 17.8.752).

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

6. Boiler #10 shall be fitted with ULNBs, flue gas recirculation (FGR) and steam injection to the flame zone (ARM 17.8.752), and have a minimum stack height of 75 feet above ground level (ARM 17.8.749).

C. Monitoring Requirements

1. CHS shall install, operate, and maintain a CEMS/CERMS on Boiler #10, to monitor and record the NO_x and O_2 for demonstration of compliance with the limits in Sections V.B, for each day when the boiler is combusting fuel gas (40 CFR 60, Subpart Db).

2. Boiler #10's continuous NO_x and O_2 concentration monitors shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts Db, Appendix B (Performance Specifications 2 and 3), and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.340, ARM 17.8.105 and ARM 17.8.749).

3. CHS shall install, operate, and maintain a CEMS/CERMS on Boiler #10, to monitor and record the CO for demonstration of compliance with the limits in V.B, for each day when the boiler is combusting fuel gas. The CO CEMS shall comply with all applicable provisions of 40 CFR 60, Appendix B (Performance Specification 4) and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.749).

4. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated (ARM 17.8.749).

5. CHS shall install and operate a volumetric stack flow rate monitor on Boiler #10 that shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Appendix B, Performance Specifications 6; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).

D. Testing Requirements

Boiler #10 shall be tested for NO_x and CO, concurrently at a minimum of every 5 years or according to another testing/monitoring schedule as may be approved by the Department. Boiler #10 shall be tested for VOC as requested by the Department. (ARM 17.8.105 and ARM 17.8.106).

E. Compliance Determinations

1. Compliance with the opacity limitations shall be determined according to 40 CFR, Part 60, Appendix A, Method 9 Visual Determination of Opacity of Emissions from Stationary Sources (ARM 17.8.749).

2. With exception to the initial performance test period, compliance with the lb/MMBtu limit(s) will be demonstrated using statistically significant F-factor values. The factor will be updated on a regular basis using data from all valid fuel gas samples representative of the fuel gas burned in Boiler #10. The method of compliance demonstration involving F-factor statistical significance is subject to change upon agreement with the Department and CHS (40 CFR 60, Appendix A, Reference Method 19).

3. Compliance with the NO_x lb/hr limit shall be determined using the NO_x CEM and the volumetric stack flow rate monitor (ARM 17.8.749).

4. Compliance with the CO lb/hr limit in Section V.B shall be determined using the CO CEM and the volumetric stack flow rate monitor (ARM 17.8.749).

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

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer (or equivalent service). The report shall include the following:

   a. summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

   b. a summary report for all CEMS required by this section.

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

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

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart CC - National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries.

3. The product loading rack and vapor combustion unit shall be operated and maintained as follows:

   a. CHS's product loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from cargo tanks during gasoline product loading (ARM 17.8.342 and ARM 17.8.752).

   b. CHS's collected vapors shall be routed to the VCU at all times. In the event the VCU is inoperable, CHS may continue to load distillates with a Reid vapor pressure of less than 27.6 kilopascals, provided the Department is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.749).

   c. The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline cargo tank from exceeding 4,500 Pascals (Pa) (450 millimeters (mm) of water) during product loading. This level shall not be exceeded when measured by the procedures specified in the test methods and procedures in 40 CFR 60.503(d) (ARM 17.8.342).

   d. No pressure-vacuum vent in the permitted terminal's vapor collection system shall begin to open at a system pressure less than 4,500 Pa (450 mm of water) (ARM 17.8.342).

   e. The vapor collection system shall be designed to prevent any VOC vapors collected at one loading rack from passing to another loading rack (ARM 17.8.342).

   e. Loadings of liquid products into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using the following procedures (ARM 17.8.342):

      i. CHS shall obtain annual vapor tightness documentation described in the test methods and procedures in 40 CFR 63.425(e) for each gasoline cargo tank that is to be loaded at the product loading rack.

      ii. CHS shall require the cargo tank identification number to be recorded as each gasoline cargo tank is loaded at the terminal.

iii. CHS shall cross-check each tank identification number obtained during product loading with the file of tank vapor tightness documentation within 2 weeks after the corresponding cargo tank is loaded.

iv. CHS shall notify the owner or operator of each non-vapor-tight cargo tank loaded at the product loading rack within 3 weeks after the loading has occurred.

v. CHS shall take the necessary steps to ensure that any non-vapor-tight cargo tank will not be reloaded at the product loading rack until vapor tightness documentation for that cargo tank is obtained, which documents that:

aa. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e) to this permit.

bb. For each gasoline cargo tank failing the test requirements in 40 CFR 63.425(f) or (g), the gasoline cargo tank must either:

1. Before the repair work is performed on the cargo tank, meet the test requirements in 40 CFR 63.425 (g) or (h), or

2. After repair work is performed on the cargo tank before or during the tests in 40 CFR 63.425 (g) or (h), subsequently pass the annual certification test described in 40 CFR 63.425(e).

f. 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 stack for the truck loading rack shall be at least 40 feet above grade (ARM 17.8.749).

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.

3. Subpart XX - Standards of Performance for Bulk Gasoline Terminals.

C. Emission Limitations

1. The total annual VOC emissions from the truck loading rack, VCU and associated equipment (which includes all associated storage tanks (135-139, 142, 143 and Additive Tanks # 1-4)), and any fugitives shall not exceed 39.23 TPY based on a rolling 12-calendar month total. This is total combined VOC emission limit for the applicable units listed in this Section (VI) and Section XVI (ARM 17.8.749).

2. VCU Emission Limitations

   a. The total VOC emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 milligrams per liter (mg/L) of gasoline loaded (ARM 17.8.342, 40 CFR 63, Subpart CC, and ARM 17.8.752).

   b. The total CO emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 mg/L of gasoline loaded, testing as requested by the Department (ARM 17.8.752).

   c. The total NOx 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, testing as requested by the Department (ARM 17.8.752).

   d. CHS shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU any visible emissions that exhibit an opacity of 20% or greater over any 6 consecutive minutes (ARM 17.8.304(2)).

D. Monitoring Requirements

1. CHS shall perform the testing and monitoring procedures specified in 40 CFR §§63.425 and 63.427 of Subpart R, except §63.425(d) or §63.427(c) (ARM 17.8.342).

2. CHS shall install and operate a continuous parameter monitoring system capable of measuring temperature in the firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs (ARM 17.8.342 and 40 CFR 63, Subpart CC).

3. CHS shall monitor and maintain all pumps, shutoff valves, relief valves and other piping and valves associated with the gasoline loading rack as described in 40 CFR Parts 60.482-1 through 60.482-10 (ARM 17.8.340).

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

E. Testing Requirements

1. CHS shall comply with all test methods and procedures as specified by Subpart R §63.425 (a) through (c), and §63.425 (e) through (h). This shall apply to, but not be limited to, the product loading rack, the vapor processing system, and all gasoline equipment located at the product loading rack.

2. The product loading rack VCU shall be tested for VOCs, and compliance demonstrated with the emission limitation contained in Section VI.C.1 and C.2 on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department. CHS shall perform the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).

3. The product loading rack VCU shall be tested for CO and NO_x, concurrently, and compliance demonstrated with the CO and NO_X emission limitations contained in Section VI.B.2.b and c. Testing shall be conducted as requested by the Department (ARM 17.8.105).

F. Operational and Emission Inventory Reporting Requirements

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

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

2. Subpart CC - CHS shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63.655 of Subpart R.

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

A. CHS shall comply with all applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR Part 60 for the No. 1 Crude Unit. The following subparts, at a minimum, are applicable (ARM 17.8.340):

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to the No. 1 Crude Unit fugitive piping equipment in VOC service as appropriate.

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

1. Subpart A - General Provisions applies to all equipment or facilities subject

to a NESHAP for source categories subpart as listed below.

2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (Refinery MACT I).

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

1. The No. 1 Crude Unit shall be maintained and operated as per the Leak Detection and Repair (LDAR) Program. The LDAR program would apply to new equipment in both HAP and non-HAP VOC service in the No. 1 Crude Unit. The LDAR program would not apply to existing equipment in non-HAP service undergoing retrofit measures.

2. CHS shall monitor and maintain all pumps, shutoff valves, relief valves and other piping and valves associated (as defined above) with the No. 1 Crude Unit as described in 40 CFR 60.482-1 through 60.482-10. Records of monitoring and maintenance shall be maintained on site for a minimum of 2 years.

D. Monitoring Requirements

CHS shall monitor with the LDAR database the type and number of new fugitive VOC components added (ARM 17.8.749).

E. Operational and Emission Inventory Reporting Requirements

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

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

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart J - Standards of Performance for Petroleum Refineries applies to the two ULSD Unit heaters (H-901 and H-902).

3. Subpart Ja - Standards of Performance for Petroleum Refineries applies to the H-1001 Reformer Heater.

4. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the ULSD Unit and the Hydrogen Plant fugitive piping equipment in VOC service.

5. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the ULSD Unit and

Hydrogen Plant process drains.

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart CC - NESHAP from Petroleum Refineries shall apply to, but not be limited to, Tank 96 when it is utilized in gasoline service.

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

D. Limitations on Individual Sources (ARM 17.8.752)

1. Reactor Charge Heater H-901

    a. SO_2 emissions from H-901 shall not exceed (ARM 17.8.752):

        i. 1.96 tons/rolling 12-calendar month total

        ii. 0.90 lb/hr

    b. NO_x emissions from H-901 shall not exceed (ARM 17.8.752):

        i. 2.86 tons/rolling 12-calendar month total

        ii. 0.65 lb/hr based on a 365-day rolling average (recalculated daily)

    c. CO emissions from H-901 shall not exceed 11.76 tons/rolling 12-calendar month total (ARM 17.8.752).

    d. VOC Emissions from H-901 shall not exceed 0.77 tons/rolling 12-calendar month total (ARM 17.8.752).

2. Fractionator Reboiler H-902

    a. SO_2 emissions from H-902 shall not exceed (ARM 17.8.752):

        i. 3.95 tons/rolling 12-calendar month total

        ii. 1.80 lb/hr

    b. NO_x emissions from H-902 shall not exceed (ARM 17.8.752):

        i. 5.70 tons/rolling 12-calendar month total

        ii. 1.30 lb/hr based on a 365-day rolling average (recalculated daily)

    c. CO emissions from H-902 shall not exceed (ARM 17.8.752):

    11.01 tons/rolling 12-calendar month total

    d. VOC Emissions from H-902 shall not exceed 1.54 tons/rolling 12-calendar month total (ARM 17.8.752).

3. Reformer Heater H-1001

    a. The H-1001 Reformer Heater shall be equipped with ULNBs (ARM 17.8.752).

    b. All available 1000 Unit PSA purge gas (sulfur free) shall be fired in the H-1001 Reformer Heater except during periods of startup, shutdown, operational transition, or process upset (ARM 17.8.752).

    c. CHS shall not burn in the H-1001 Reformer Heater any fuel gas that contains H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja).

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

        i. 40 ppmv (dry basis, corrected to 0 percent excess air) based on a 30-day rolling average (40 CFR 60, Subpart Ja).

        ii. 29.4 tons per rolling 12-calendar month total (ARM 17.8.752).

        iii. 7.7 lb/hr based on a rolling 24-hour average (ARM 17.8.752).

    e. CO emissions from H-1001 shall not exceed (ARM 17.8.752):

        i. 16.8 tons per rolling 12-calendar month total.

        ii. 7.7 lb/hr during periods of startup and shutdown, based on a 24-hour rolling average.

    f. CO, VOC and PM/PM_{10} emissions shall be controlled by proper design and good combustion practices (ARM 17.8.752).

E. Monitoring Requirements

1. CHS shall install and operate the following CEMS/CERMS for the Reactor Charge Heater H-901 and the Fractionator Reboiler H-902 (ARM 17.8.749):

    a. NO_X

    b. Volumetric flowrate monitor

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, 60.100-60.108, and Appendix B, Performance Specifications 2, 3, 6, and Appendix F; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749)

3. CHS shall install and operate the following (CEMS/CERMS) for H-1001:

   a. NO_x/O_2 (40 CFR 60, Subpart Ja)

   b. CO (ARM 17.8.749)

   c. Volumetric flow rate monitor

4. CEMS and CERMS required for H- 1001 shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts Ja, 60.100a-60.108a, and Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).

5. All 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.

6. Compliance with the Reformer Heater H-1001 NO_X and CO emission limits shall be determined using the NO_X/CO CEMs and the volumetric stack flow rate monitor (with appropriate moisture correction, determined from the annual stack test data (RATA)).

7. Compliance with the H-901 and H-902 NO_X emission limits shall be determined using the NO_X CEMs and the volumetric stack flow rate monitor (with appropriate moisture correction, determined from the annual stack test data (RATA)). Compliance with the H-901 and H-902 CO emission limits shall be determined from emissions factors generated from the most recent CO stack test (CO testing, concurrent with NO_X testing, as required by Section VIII.F.1 and VIII.F.2).

F. Testing Requirements

1. The Reactor Charge Heater (H-901) shall be tested every three years from the date of the last source test, 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 of the H-901 process heater (ARM 17.8.105 and ARM 17.8.749).

2. The Fractionator Reboiler (H-902) shall be tested every three years from the date of the last source test, 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 of the H-902 process heater (ARM 17.8.105 and ARM 17.8.749).

3. The Reformer Heater (H-1001) shall be tested every three years from the date of the last source test, 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 of the H-1001 process heater, as applicable (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations (ARM 17.8.749)

1. In addition to stack testing required in Section VIII.F, compliance determinations for the NO_X limit for H-901, H-902, and H-1001 shall also be based upon monitoring data as required in Section VIII.E.

2. Compliance with the opacity limitation listed in Section VIII.C shall be determined using EPA Reference Method 9 testing by a qualified observer.

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

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service (or equivalent service). The report shall include the following:

   a. summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

   b. a summary report for all CEMS required by this section.

Section IX: Limitations and Conditions for the TGTU for Zone A's SRU #1 and SRU #2 trains and Zone A's Sulfur Recovery Plants

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart J - Standards of Performance for Petroleum Refineries applies to Zone A's SRU #1 and #2 tail gas incinerator (SRU-INC-22) stack.

3. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the TGTU process drains as applicable.

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart UUU - MACT Standard for Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.

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

D. The Department determined, based on modeling provided by CHS, that the SRU-INC-22 stack shall be maintained at a height no less than 132 feet.

E. Limitations on Individual Sources

1. SO_2 emissions from the SRU-INC-22 stack shall not exceed:

a. 250 ppmvd at 0% oxygen, on an hourly rolling 12-hour average except during periods of startup, shutdown, and malfunction (ARM 17.8.749, ARM 17.8.752 and 40 CFR Part 60, Subpart Ja)

b. 200 ppm, rolling 12-month average corrected to 0% oxygen, on a dry basis (ARM 17.8.749)

c. 40.66 tons/rolling 12-month total

d. 11.60 lb/hr

e. 278.40 lb/day

f. CHS shall minimize the frequency and duration of startups and shutdowns of the Zone A SRP by operating at all times in accordance with an operation, maintenance, and monitoring plan meeting the requirements of 40 CFR 63.1574(f) (ARM 17.8.749 and ARM 17.8.752).

g. CHS shall comply with 40 CFR 63 subpart UUU (Refinery MACT II) operating limits at 40 CFR 63.1568(a)(4) during periods of startup and shutdown (ARM 17.8.749 and ARM 17.8.752).

2. NO_x emissions from the SRU-INC-22 stack shall not exceed:

   a. 4.8 tons/rolling 12-calendar month total

   b. 1.09 lb/hr

3. Molten Sulfur Truck Loading and Transport:

   CHS shall meet the following requirements for Zone A Molten Sulfur Truck Loading:

   a. CHS shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter. CHS shall treat unpaved molten sulfur trucking transport roads with water and/or chemical dust suppressant as necessary to control emissions while molten sulfur is being transported on roads on the refinery property (ARM 17.8.308 and ARM 17.8.752).

   b. CHS shall clean the paved sections of molten sulfur transport roads, as necessary, for reasonable precautions specific to truck hauling of molten sulfur on refinery property (ARM 17.8.308 and ARM 17.8.752).

   c. CHS is subject to ARM 17.8.304(2) for visible opacity limits of 20 percent for molten sulfur truck loading (ARM 17.8.304 and ARM 17.8.749).

F. Monitoring Requirements

1. CHS shall install and operate the following CEMS/CERMS on the Zone A SRU-INC-22 Stack:

   a. SO_2 (40 CFR 60, Subpart J and Billings SO_2 SIP)

   b. O_2 (40 CFR 60, Subpart J)

   c. Volumetric Flow Rate (Billings SO_2 SIP)

2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, 60.100-108 and Appendix B, Performance Specifications 2, 3, 6, and Appendix F. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.

3. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.

G. Testing Requirements

The SRU-INC-22 Stack shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department for SO_2 and shall be tested on an every 6-year basis, or according to another testing/monitoring schedule as may be approved by the Department, for NOx. 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 IX.E.1, 2, and 3 (ARM 17.8.105 and ARM 17.8.749).

H. Compliance Determinations (ARM 17.8.749)

1. In addition to the testing required in Section IX.G, compliance determinations for ppm concentration, hourly, 3-hour, 24-hour, rolling 12-month, and annual SO_2 limits for the SRU-INC-22 Stack shall be based upon CEMS data utilized for SO_2 as required in Section IX.F.1.

2. Compliance with the opacity limitation listed in Section IX.C shall be determined using EPA reference method 9 testing by a qualified observer.

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

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service (or equivalent service). The report shall include the following:

   a. summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

   b. a summary report for all CEMS required by this section.

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

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart J - Standards of Performance for Petroleum Refineries applies to the

FCCU Regenerator for SO_2, CO, and PM.

3. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (The FCCU Regenerator Stack is subject to NSPS Subpart Ja for CO only, and the FCCU Charge Heater (FCC-Htr-1) is subject to the fuel gas combustion device and process heater requirements).

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart CC - Refinery MACT I shall apply to, but not be limited to, certain parts of the FCCU piping.

3. Subpart UUU - Refinery MACT II shall apply to, but not be limited to, the FCCU.

C. Opacity

1. CHS shall not cause or authorize emissions to be discharged from the FCCU Regenerator Stack into the outdoor atmosphere that exhibit an opacity greater than 30%, except for one six-minute average opacity reading in any one-hour period (ARM 17.8.304, ARM 17.8.340, 40 CFR Part 60, Subpart J).

2. This condition applies to the FCC Charge Heater (FCC-Htr-1). CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304). During the building of new fires, cleaning of grates, or soot blowing, the provisions of ARM 17.8.304(1) and (2) shall apply, except that a maximum average opacity of 60% is permissible for not more than one 4-minute period in any 60 consecutive minutes. Such a 4-minute period means any 4 consecutive minutes (ARM 17.8.304(3)).

D. Limitations on Individual Emitting Units

1. FCCU Regenerator Stack

a. CO emissions from the FCCU Regenerator Stack shall not exceed 500 ppmv, dry basis corrected to 0% excess air, on an hourly average basis (ARM 17.8.340, 40 CFR Part 60, Subpart Ja, and ARM 17.8.752).

b. CO emissions from the FCCU Regenerator Stack shall not exceed 100 ppm_{vd} at 0% O_2, on a 365-day rolling average basis (ARM 17.8.749).

c. CHS shall not exceed 50 ppm SO_2 by volume (corrected to 0% O_2) on a 7-day rolling average and shall also comply with an SO_2 concentration limit of 25 ppm_{vd} at 0% O_2 on a 365-day rolling average basis (ARM 17.8.340, 40 CFR Part 60, Subpart J, and ARM 17.8.752).

d. PM emissions from the FCCU Regenerator Stack shall be controlled with an ESP. PM emissions from the FCCU Regenerator Stack shall not exceed 1.0 lb PM/1,000 lb of coke burned (ARM 17.8.340, 40 CFR Part 60, Subpart J, and ARM 17.8.752).

e. NO_x emissions from the FCCU Regenerator Stack shall not exceed 65.1 ppm_{vd} at 0% oxygen on a 365-day rolling average basis. This long-term limit shall apply at all times (including during startup, shutdown, and malfunction), that the FCCU Regenerator Stack is operating (ARM 17.8.749 and ARM 17.8.752).

f. NO_x emissions from the FCCU Regenerator Stack shall not exceed 102 ppm_{vd} at 0% oxygen on a 7-day rolling average basis. This short-term limit shall exclude periods of startup, shutdown, and malfunction, but shall apply at all other times that the FCCU is operating. For days and hours in which the FCCU Regenerator Stack is not operating, no NOx value shall be used in the average, and those periods shall be skipped in determining compliance with the 7-day and 365-day averages (ARM 17.8.749 and ARM 17.8.752).

g. NO_x emissions from the FCCU Regenerator Stack shall not exceed 117 tons per 12-month rolling average (limit is based on 65.1 ppm_{vd} at 0% oxygen on a 365-day rolling average) (ARM 17.8.749).

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

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

   a. The FCC-Htr-1 shall be equipped with ULNBs (ARM 17.8.752).

   b. NOx emissions from FCC-Htr-1 shall not exceed:

      i. 40 ppmv (dry basis, corrected to 0 percent excess air) based on a 30-day rolling average (40 CFR 60, Subpart Ja and ARM 17.8.752).

      ii. 10.1 tpy based on a 12-calendar month total (ARM 17.8.752).

      iii. 2.6 lb/hr based on a 24-hour rolling average (ARM 17.8.752).

   c. CO emissions from FCC-Htr-1 shall not exceed 100 ppmv at 3% oxygen based on a 24-hour rolling average (ARM 17.8.752).

d. CHS shall not combust any fuel gas that contains H_2S in excess of 60 ppmv determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja).

e. CHS shall implement proper design and good combustion techniques to minimize CO, VOC, and $PM/PM_{10}/PM_{2.5}$ emissions (ARM 17.8.752).

E. Monitoring Requirements

1. CHS shall install and operate the following CEMS/CERMS on the FCCU Regenerator Stack:

    a. CO (40 CFR 60, Subpart Ja)

    b. NO_x (ARM 17.8.749)

    c. SO_2 (40 CFR 60, Subpart J, Billings/Laurel SO_2 SIP)

    d. O_2 (40 CFR 60, Subpart J, Subpart Ja, and Billings/Laurel SO_2 SIP)

    e. Opacity (40 CFR 60, Subpart J, 40 CFR 63, Subpart UUU)

    f. Volumetric stack flow rate monitor (Billings/Laurel SO_2 SIP)

2. CHS shall install and operate the following on the FCC-Htr-1:

    a. NO_X/O_2 CEMS (40 CFR 60, Subpart Ja)

    b. Volumetric stack flow rate monitor (ARM 17.8.749)

3. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts J, 60.100-108, Subparts Ja, 60.100a-108a and Appendix B, Performance Specifications 1, 2, 3, 6, and Appendix F. The volumetric flow rate monitor(s) shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1.

4. The FCCU Regenerator Stack, stack gas volumetric flow rate CEMS shall comply with all applicable requirements of the Billings/Laurel SO2 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.

    The FCC-Htr-1 CEMS shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts Ja, 60.100a-60.108a, and Appendix B, Performance Specifications 2, 3, 6, and Appendix F; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).

5. Compliance with the emission limit in Section X.D.2.b shall be determined using the NO_X/O_2 CEMs and the volumetric stack flow rate monitor (with appropriate moisture correction).

    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 every three years from the date of the last source test or on another testing schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.340, and 40 CFR 60, Subpart J).

2. The FCC Charge Heater (FCC-Htr-1) shall be tested every three years from the date of the last source test in conjunction with annual CEMS/CERMS RATA performance testing in accordance with Appendix F (40 CFR Part 60) requirements, or according to another testing/ monitoring schedule as may be approved by the Department, for NO_x/O_2 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 X.D.2.c (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations

1. Compliance determinations for the FCCU Regenerator Stack emission limits in Section X.D for NO_x, CO, and SO_2 shall be based upon monitor data, as required in Section X.E.1.

2. Compliance determinations for the FCC-Htr-1 emission limits in Section X.D shall be based upon monitor data (for NO_x) or source test results (for NO_x and CO), as required in Section X.E.2 and X.F.2.

3. Compliance with the opacity limitations listed in Section X.C shall be determined using EPA reference method 9 observations by a qualified observer or a certified continuous opacity monitor system (COMS).

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

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall submit a quarterly report within 30 days of the
end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service (or equivalent service). The report shall include the following:

   a. summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

b. a summary report for all CEMS required by this section.

Section XI: Limitations and Conditions for the Naphtha Hydrotreating Unit, Delayed Coker Unit (From MAQP #1821-13) and Zone E SRU/TGTU/TGI

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart J - Standards of Performance for Petroleum Refineries applies to the NHT Charge Heater (H-8301), the Coker Charge Heater (H-7501), and the Zone E SRU/TGTU/TGI.

3. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to the Coker Unit flare.

4. Subpart GGG - Standards of Performance for Equipment leaks of VOC in Petroleum Refineries applies to the Naphtha Hydrotreating Unit and the Delayed Coker Unit fugitive piping equipment in VOC service. Once the MUE Project is complete, the DCU and NHT process units will be required to comply with a program meeting requirements of Subpart GGGa.

5. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to the Delayed Coker Unit process drains.

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart CC - Refinery MACT I shall apply to, but not be limited to, affected sources or the collection of emission points as defined in this subpart.

3. Subpart UUU - Refinery MACT II shall apply to, but not be limited to, the Zone E SRU/TGTU/TGI.

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

D. Limitations on Individual Sources

1. NHT Charge Heater (H-8301)

   a. SO_2 emissions from the NHT Charge Heater (H-8301) shall not exceed (ARM 17.8.752):

      i. 1.54 tons/rolling 12-calendar month total

      ii. 0.70 lb/hr

   b. NO_x emissions from the NHT Charge Heater (H-8301) shall not exceed (ARM 17.8.752):

      i. 6.55 tons/rolling 12-calendar month total

      ii. 1.50 lb/hr

   c. CO emissions from the NHT Charge Heater (H-8301) shall not exceed 400 ppm_{vd} at 3% oxygen on a 30-day rolling average (ARM 17.8.752).

   d. VOC Emissions from the NHT Charge Heater (H-8301) shall not exceed 0.86 tons/rolling 12-calendar month total (ARM 17.8.752).

2. Coker Charge Heater (H-7501)

   a. SO_2 emissions from the Coker Charge Heater (H-7501) shall not exceed (ARM 17.8.752):

      i. 6.61 tons/rolling 12-calendar month total

      ii. 3.02 lb/hr

   b. NO_x emissions from the Coker Charge Heater (H-7501) shall not exceed (ARM 17.8.752):

      i. 28.2 tons/rolling 12-calendar month total

      ii. 6.44 lb/hr

   c. CO emissions from the Coker Charge Heater (H-7501) shall not exceed (ARM 17.8.752):

      i. 400 ppm_{vd} at 3% oxygen on a 30-day rolling average

      ii. 35.2 tons/rolling 12-calendar month total

      iii. 8.05 lb/hr

   d. During periods of startup, shutdown, and spalling (a feed heater coil decoking process completed during operation to avoid complete unit shutdown), CO emissions from the Coker Charge Heater (H-7501) shall not exceed 16.1 lb/hr on a 24-hour rolling average (ARM 17.8.752).

e. VOC Emissions from the Coker Charge Heater (H-7501) shall not exceed 1.41 tons/rolling 12-calendar month total (ARM 17.8.752).

3. The Coker unit flare shall operate with a continuous pilot flame and a continuous pilot flame-operating device and meet applicable control device requirements of 40 CFR 63.670 and 40 CFR 63.671 (40 CFR 63.670, 40 CFR 63.671 and ARM 17.8.752).

4. VOC emissions from the Sour Water Storage Tank (TK-129) shall be controlled by the installation and use of an internal floating roof and a submerged fill pipe (ARM 17.8.752).

5. VOC emissions from the Coker Sludge Storage Tank (TK-7504) shall be controlled by the installation and use of a fixed roof, a submerged fill pipe, and a conservation vent (ARM 17.8.752).

6. Coke processing operations

   a. CHS shall store onsite coke in the walled enclosure for coke storage only. Onsite coke storage shall be limited to a volume that is contained within the walled enclosure. Storage of coke outside of the walled enclosure is prohibited (ARM 17.8.752).

   b. The coke pile shall not exceed the height of the enclosure walls adjacent to the pile at any time (ARM 17.8.752).

   c. CHS shall not cause or authorize emissions to be discharged into the atmosphere from coke handling without taking reasonable precautions to control emissions of airborne particulate matter. CHS shall wet the coke as needed to comply with the reasonable precautions standard (ARM 17.8.308 and ARM 17.8.752).

   d. CHS shall install and maintain enclosures surrounding the coke conveyors, coke transfer drop points (not including the location at which coke is transferred from the front-end loader to the initial coke sizing screen), and crusher (ARM 17.8.752).

   e. CHS shall install and maintain a telescoping loading spout for loading coke into railcars and trucks (ARM 17.8.752).

   f. Alternate Coke Handling Method: In the event the conveyors are inoperable (as described in Section XI.D.6.d and e) due to either planned or unplanned maintenance activities, CHS may transport uncrushed coke only from the coke storage area to the railcar using a front-end loader. The requirements specified in Section XI.D.6.a – c still apply. The alternate coke handling method is limited to 24 batches per year (ARM 17.8.752).

g. CHS shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter. CHS shall treat unpaved coke trucking transport roads with water and/or chemical dust suppressant as necessary to control emissions while coke is being transported from the refinery (ARM 17.8.308 and ARM 17.8.752).

h. CHS shall clean the paved sections of coke transport roads, as necessary, for reasonable precautions specific to truck hauling of coke on refinery property (ARM 17.8.308 and ARM 17.8.752).

i. CHS shall cover the coke during truck transport of the coke from the refinery (ARM 17.8.752).

j. CHS shall load no more than 175,200 tons of coke into trucks per year, as determined monthly on a rolling 12-month period (ARM 17.8.749).

7. Zone E SRU/TGTU/TGI

a. SO_2 emissions from the Zone E SRU/TGTU/TGI shall not exceed (ARM 17.8.752):

i. 49.4 tons/rolling 12-calendar month total (based on 200 ppm, rolling 12-month average corrected to 0% oxygen, on a dry basis)

ii. 14.1 lb/hr (based on 250 ppm, rolling 12-hour rolling average corrected to 0% oxygen, on a dry basis)

b. CHS shall operate and maintain the TGTU on the Coker Unit to limit SO_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 (ARM 17.8.749).

c. NO_x emissions from the Zone E SRU/TGTU/TGI shall not exceed (ARM 17.8.749):

i. 4.62 tons/rolling 12-calendar month total

ii. 1.05 lb/hr

d. CHS shall not cause or authorize to be discharged into the atmosphere from the TGI:

i. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.752)

ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO_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).

9. Coke Drum Steam Vent

   a. VOC emissions from the Coke Drum Steam Vent shall not exceed 18.10 tons/yr as determined on a monthly rolling 12-month total (ARM 17.8.749).

   b. PM_{10} emissions from the Coke Drum Steam Vent shall not exceed 4.52 tons/yr as determined on a monthly rolling 12-month total (ARM 17.8.749).

   c. CHS shall depressure each coke drum to a closed blowdown system until either (ARM 17.8.342 and 40 CFR 63 Subpart C):

      i. The coke drum average pressure is 2 psig or less, determined on a rolling 60-event average or:

      ii. The coke drum average vessel temperature is 220 degrees Fahrenheit or less, determined on a rolling 60-event average.

10. Molten Sulfur Truck Loading and Transport: CHS shall meet the following requirements for Zone E Molten Sulfur Truck Loading:

    a. CHS shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter. CHS shall treat unpaved molten sulfur trucking transport roads with water and/or chemical dust suppressant as necessary to control emissions while molten sulfur is being transported on roads on refinery property (ARM 17.8.308 and ARM 17.8.752).

    b. CHS shall clean the paved sections of molten sulfur transport roads, as necessary, for reasonable precautions specific to truck hauling of molten sulfur on refinery property (ARM 17.8.308 and ARM 17.8.752).

    c. CHS is subject to ARM 17.8.304(2) for visible opacity limits of 20 percent for molten sulfur truck loading (ARM 17.8.304 and ARM 17.8.749).

E. Monitoring requirements

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

   Zone E SRU/TGTU/TGI (Billings/Laurel SO_2 SIP)

   a. SO_2 (40 CFR 60, Subpart J)

   b. O_2 (40 CFR 60, Subpart J)

   c. Volumetric Flow Rate (ARM 17.8.749)

2. CEMS and CERMS required by this permit shall comply with all applicable

provisions of 40 CFR Part 60.5 through 60.13, Subparts J, 60.100-108, and Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F. The volumetric flow rate monitor shall comply with the Billings/Laurel SIP Pollution Control Plan Exhibit A, Attachment 1 Methods A-1 and B-1 (ARM 17.8.749).

3. The Delayed Coker Unit SO_2 CEMS, stack gas volumetric flow rate 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 (ARM 17.8.749).

4. CHS shall install and operate the following (CEMS/CERMS): Zone E SRU/TGTU/TGI a. SO_2 (40 CFR 60, Subpart J) b. O_2 (40 CFR 60, Subpart J) c. Volumetric Flow Rate (ARM 17.8.749).

   CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subparts J, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F; and 40 CFR 52, Appendix E, for Volumetric Flow Rate Monitors (ARM 17.8.749).

5. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated (ARM 17.8.749).

6. CHS shall continuously monitor the pressure in the coke drums such that the pressure at which each drum is depressurized can be determined (40 CFR 63 657 and ARM 17.8.749).

F. Testing Requirements

1. The NHT Charge Heater (H-8301) shall be tested every 2 years from the date of the last source test, 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 XI.D.1.b and c (ARM 17.8.105 and ARM 17.8.749).

2. The Coker Charge Heater (H-7501) shall be tested every three years from the date of the last source test, 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 XI.D.2.b and c (ARM 17.8.105 and ARM 17.8.749).

3. The Zone E SRU/TGTU/TGI stack shall be tested every three years from the date of the last source test, or according to another testing/monitoring schedule as may be approved by the Department for SO_2 and shall be tested

on an every 6-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 XI.D.7.a, b, and c, respectively (ARM 17.8.105 and ARM 17.8.749).

G. Compliance Determinations (ARM 17.8.749).

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

2. Compliance with the opacity limitation listed in Section XI.C shall be determined using EPA reference method 9 observations by a qualified observer or a certified COMS.

3. Using the following equations, CHS shall determine the VOC and PM_{10} emissions from the Coke Drum Steam Vent each time a steam vent is opened to the atmosphere (cycle). CHS shall sum emissions from all cycles on a rolling 12-month basis to determine compliance with the emissions limits (ARM 17.8.749).

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

$$VOC, lb/cycle = \left(\frac{15}{2} \Big/ \frac{65}{4}\right)\left(2.6378P^3 - 33.487P^2 + 144.5P - 37.706\right)$$

P = 5-minute rolling average coke drum pressure (psig) as determined just prior to initiating steps to isolate the coke drum prior to venting, draining or deheading.

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

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall submit a quarterly report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer (or equivalent service). The report shall include the following:

   a. summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

   b. a summary report for all CEMS required by this section.

Section XII: Limitations and Conditions for Boiler #11

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart J - Standards of Performance for Petroleum Refineries applies to Boiler #11.

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

4. Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006, applies to Boiler #11.

B. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in Boiler #11 (ARM 17.8.304 (2)).

C. Limitations on Boiler #11

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

   a. 8.59 tons/rolling 12-calendar month total

   b. 3.92 lb/hr

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

   a. 27.5 tons/rolling 12-calendar month total (ARM 17.8.752)

   b. 6.27 lb/hr, rolling 365-day average (ARM 17.8.752)

3. During periods of startup or shutdown, CO emissions from Boiler #11 shall not exceed 23 lb/hr on a 24-hour rolling average (ARM 17.8.752). Otherwise, CO emissions shall not exceed (ARM 17.8.752):

   a. 400 ppm_{vd} at 3% oxygen on a 30-day rolling average

   b. 36.63 tons/rolling 12-calendar month total

   c. 15.26 lb/hr

4. VOC Emissions from the Boiler #11 shall not exceed 4.83 tons/rolling 12-

calendar month total (ARM 17.8.752).

D. Monitoring requirements

1. CHS shall install and operate the following (CEMS/CERMS) for Boiler #11:

    a. NO_x (40 CFR 60, Subpart Db)

    b. O_2 (40 CFR 60, Subpart Db)

2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subpart Db; 60.40b through 60.49b, and Appendix A, Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F.

3. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated.

4. CHS shall install and operate a volumetric stack flow rate monitor on Boiler #11 that shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Appendix B, Performance Specifications 6; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).

E. Testing Requirements

Boiler #11 shall be tested every three years from the date of the last source test, 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 XII.C.2 and 3 (ARM 17.8.105 and ARM 17.8.749).

F. Compliance Determinations (ARM 17.8.749)

1. In addition to stack testing required in Section XII.E, compliance determinations for the NO_x limit in Section XII.C for Boiler #11 shall also be based upon monitoring data as required in Section XII.D.

2. Compliance with the opacity limitation listed in Section XII.B shall be determined using EPA Reference Method 9 observations by a qualified observer or a certified COMS.

3. Compliance with the lb/MMBtu limit(s) will be demonstrated using statistically significant F-factor values. The factor will be updated on a regular basis using data from all valid fuel gas samples representative of the fuel gas burned in Boiler #11. The method of compliance demonstration involving F-factor statistical significance is subject to change upon agreement with the Department and CHS (40 CFR 60, Appendix A, Reference Method 19).

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

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall submit a quarterly report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service (or equivalent service). The report shall include the following:

   a. summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

   b. a summary report for all CEMS required by this section.

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

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart CC - Refinery MACT I shall apply to, but not be limited to, the product loading rack and VCU. The Gasoline Loading Rack provisions in Subpart CC require compliance with certain Subpart R provisions.

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

1. CHS' railcar light product loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from railcars during gasoline product loading (ARM 17.8.342 and ARM 17.8.752).

2. CHS' collected vapors shall be routed to the VCU at all times. In the event the VCU is inoperable, CHS may continue to load distillates with a Reid vapor pressure of less than 27.6 kilopascals, provided the Department is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.749).

3. Loadings of liquid products into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using procedures as listed in 40 CFR 63, Subpart R (ARM 17.8.342 and ARM 17.8.752).

C. Railcar Gasoline Component Unloading

1. CHS shall implement proper design and operating practices while unloading gasoline components via railcars (ARM 17.8.752).

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

D. 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).

E. 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 CC).

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 every 5 years, or according to another testing/monitoring schedule as may be approved by the Department. CHS shall perform the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).

4. The VCU shall be tested for CO and NO_x, concurrently, and compliance demonstrated with the CO and NO_x emission limitations contained in Section XIII.C.2 and 3. Testing shall be conducted as requested by the Department (ARM 17.8.105).

F. Operational and Emission Inventory Reporting Requirements (Railcar Gasoline Component Unloading)

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service (or equivalent service). The report shall also include the following:

   Summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

3. CHS shall comply with the recordkeeping and reporting requirements contained in 40 CFR 60, Subpart VVa (ARM 17.8.749).

Section XIV: Limitations and Conditions for Boiler #12

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units applies to Boiler #12.

3. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to Boiler #12, which meets the NSPS Subpart Ja definition of a "fuel gas combustion device."

4. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 applies to the refinery fuel gas supply lines to Boiler #12.

B. CHS shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. This applies to the sources in Boiler #12 (ARM 17.8.304 (2)).

C. Limitations on Boiler #12

1. SO_2 emissions from Boiler #12 shall not exceed (40 CFR 60, Subpart Ja, ARM 17.8.340, ARM 17.8.752):

    a. 60 ppmvd H_2S refinery fuel gas, on a rolling 365-calendar day average

    b. 5.84 tons/rolling 12-calendar month total

    c. 3.60 lb/hr

2. NO_x emissions from Boiler #12 shall not exceed (ARM 17.8.752):

    b. 27.5 tons/rolling 12-calendar month total (ARM 17.8.752)

    c. 6.27 lb/hr, rolling 365-day average (ARM 17.8.752)

3. During periods of startup or shutdown, CO emissions from Boiler #12 shall not exceed 23 lb/hr on a 24-hour rolling average (ARM 17.8.752). Otherwise, CO emissions shall not exceed (ARM 17.8.752):

    a. 400 ppm_{vd} at 3% oxygen on a 30-day rolling average

    b. 36.63 tons/rolling 12-calendar month total

    c. 15.26 lb/hr

4. VOC Emissions from the Boiler #12 shall not exceed 4.81 tons/rolling 12-calendar month total (ARM 17.8.752).

5. Boiler #12 shall be fitted with ultra-low NO_x burners with FGR (ARM 17.8.752).

D. Monitoring requirements

1. CHS shall install and operate the following (CEMS/CERMS) for Boiler #12:

    a. NO_x (40 CFR 60, Subpart Db)

    b. O_2 (40 CFR 60, Subpart Db)

2. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Part 60.5 through 60.13, Subpart Db 60.40b through 60.49b, Subparts Ja, 60.100a-108a, and Appendix A, Appendix B, Performance Specifications 2, 3, 4 or 4A, 6, and Appendix F (ARM 17.8.749 and ARM 17.8.342).

3. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns, and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated (ARM 17.8.749).

4. With exception to the initial performance test period, compliance with the lb/MMBtu limit(s) will be demonstrated using statistically significant F-factor values. The factor will be updated on a regular basis using data from all valid fuel gas samples representative of the fuel gas burned in Boiler #12. The method of compliance demonstration involving F-factor statistical significance is subject to change upon agreement with the Department and CHS (40 CFR 60, Appendix A, Reference Method 19).

5. CHS shall install and operate a volumetric stack flow rate monitor on Boiler #12. The volumetric flow rate monitor shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Appendix B, Performance Specifications 6; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).

E. Testing Requirements

Boiler #12 shall be tested every three years from the date of the last source test, 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 XIV.C.2 and 3 (ARM 17.8.105 and ARM 17.8.749).

F. Compliance Determinations (ARM 17.8.749).

1. Compliance with the opacity limitation listed in Section XIV.B shall be determined using EPA Reference Method 9 observations by a qualified observer or a certified COMS.

2. Compliance with the limit in Section XIV.C.2.c. shall be determined using the NO_x CEM required in Section XIV.D.1 and the volumetric stack flow rate monitor required in Section XIV.D.5.

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

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service (or equivalent service). The report shall include the following:

   a. summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

   b. a summary report for all CEMS required by this section.

Section XV: Benzene Reduction Unit (BRU)

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 applies to the Platformer Splitter Reboiler. The process heater NOx requirements do not apply to the Platformer Splitter Reboiler because its rated capacity is less than 40 MMBtu/hr.

3. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to all of the fugitive VOC emitting components added in the affected facility.

4. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to, but not be limited to, any new, modified, or reconstructed affected facility associated with the benzene reduction project.

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (Refinery MACT I) applies to certain parts of the Benzene Reduction Unit.

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

D. Limitations on Platformer Splitter Reboiler

1. SO_2 emissions from the Platformer Splitter Reboiler shall not exceed:
   a. 60 ppm_v H_2S in refinery fuel gas, 365-day rolling average for the Platformer Splitter Reboiler (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60, Subpart Ja)
   b. 1.18 tons/ rolling 12-calendar month total (ARM 17.8.749)
   c. 0.72 lb/hr (ARM 17.8.749)
2. NO_x emissions from the Platformer Splitter Reboiler shall not exceed:
   a. 6.99 tons/ rolling 12-calendar month total (ARM 17.8.749)
   b. 1.60 lb/hr (ARM 17.8.752)
3. CO emissions from the Platformer Splitter Reboiler shall not exceed:
   a. 13.62 tons/ rolling 12-calendar month total (ARM 17.8.749)
   b. 3.11 lb/hr (ARM 17.8.752)
4. PM/PM_{10} emissions from the Platformer Splitter Reboiler shall not exceed:
   a. 1.31 tons/ rolling 12-calendar month total (ARM 17.8.749)
   b. 0.30 lb/hr (ARM 17.8.752)
5. VOC emissions from the Platformer Splitter Reboiler shall not exceed 0.64 tons/rolling 12-calendar month total (ARM 17.8.752).
6. The Platformer Splitter Reboiler shall be fitted with ULNBs (ARM 17.8.752).
7. The heat input rate for the Platformer Splitter Reboiler shall not exceed 39.9 MMBtu-HHV/hr (ARM 17.8.749).

E. Limitations on Wastewater System Components

1. All new drains associated with the benzene reduction project will be routed to the sewer system that is NSPS Subpart QQQ compliant and all such drains will be treated as subject to NSPS Subpart QQQ requirements (ARM 17.8.752).
2. All new junction boxes/vessels constructed as part of the benzene reduction

project will be either water sealed, equipped with vent pipes meeting NSPS Subpart QQQ standards (applicable to new junction boxes), or equipped with closed vent systems and control devices that are designed and operated to meet the control requirements of NSPS Subpart QQQ (ARM 17.8.752).

F. Testing Requirements

The Platformer Splitter Reboiler (P-HTR-3) shall be tested every 5 years, 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 XV.D.2 and 3 (ARM 17.8.105 and ARM 17.8.749).

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

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service (or equivalent service). The report shall include the following:

   Summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

Section XVI: Limitations and Conditions for Storage Tanks (Tanks 135-139, 142, 143 and Additive Tanks 1-4)

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984. This applies to Tanks 135-138, 142 and 143.

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tanks 135, 136, 137, 138, 142, and 143, which are classified as Group 1 storage vessels.

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

C. Limitations for Storage Tanks

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

2. Storage Tanks 135 and 136 shall each be equipped with an external floating roof and submerged fill piping (ARM 17.8.752).

3. VOC emissions from Storage Tanks 137, 138, 142, and 143 shall be controlled by the installation and use of an internal floating roof and submerged fill piping (ARM 17.8.340, 40 CFR 60, Subpart Kb, and ARM 17.8.752).

4. Storage Tank 139 shall only store #1 or #2 diesel fuel and the VOC emissions from Storage Tank 139 shall be controlled by the installation and use of a fixed roof with pressure/vacuum vents and a submerged fill piping (ARM 17.8.749).

5. The total annual VOC emissions from the truck loading rack, VCU and associated equipment (which includes all associated storage tanks (135-139, 142, 143 and Additive Tanks # 1-4)), and any associated fugitives shall not exceed 39.23 TPY based on a rolling 12-calendar month total. This is total combined VOC emission limit for the applicable units listed in Section (XVI) and Section VI (ARM 17.8.749).

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

D. Monitoring Requirements

1. Combined VOC emissions from Storage Tanks 135-139, 142-143, and Additive tanks 1-4 shall be calculated and monitored utilizing AP42 calculation methods with key parameters of throughput and material properties. Tank emissions during periods the tank roofs are landed on its legs shall be calculated using appropriate AP-42 emissions equations (ARM 17.8.749).

2. CHS shall document, by month, the total VOC emissions from Storage Tanks 135-139, 142, 143; and Additive Tanks 1-4 and all associated fugitive sources. This must also include emissions while the roofs of the internal floating and external floating tanks are floating and emissions during time periods that the tank roofs are landed on the legs. This monthly information and the emissions relating to the operation of the new truck loading rack, VCU and all associated fugitive sources shall be used to verify compliance with the rolling 12-month limitations in Section(s) XVI.C.5 and VI.C.1.

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

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service (or equivalent service). The report shall include the following:

Summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

Section XVII: Limitations and Conditions for Storage Tank 133

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart UU - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture.

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tank 133, which is classified as a Group 2 storage vessel.

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

D. Limitations for Storage Tank 133

1. VOC emissions from Storage Tank 133 shall not exceed 12.3 tons/rolling 12-calendar month total (ARM 17.8.749).

2. Storage Tank 133 shall be a fixed roof tank with a pressure/vacuum vent and submerged fill piping. While in asphalt and gas oil service, the tank may be heated and may be operated without the pressure/vacuum vent (ARM 17.8.752).

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

E. Monitoring Requirements

VOC emissions from Storage Tank 133 shall be calculated and monitored utilizing AP42 calculation methods with key parameters of throughput and material properties (ARM 17.8.749).

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

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service (or equivalent service). The report shall include the following:

Summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

Section XVIII: Wastewater Facilities

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater System, shall apply to, but not be limited to:

   - API Separator(s)

B. Limitations for Wastewater Facilities

1. CHS shall equip, operate, and maintain the API Separators (TK-3437 and TK-3447) with a vapor collection system to collect and route emissions from the enclosed vapor space to a carbon adsorption system or thermal combustor to comply with 40 CFR 60 Subpart QQQ (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart QQQ).

2. CHS shall equip, operate, and maintain the Dissolved Gas Flotation (DGF) Units (TK-3448 and TK-3458) with a vapor collection system to collect and route emissions from the enclosed vapor space to a carbon adsorption system or thermal combustor that meets the requirements of 40 CFR 60 Subpart QQQ. These two units are not subject to 40 CFR 60 Subpart QQQ (ARM 17.8.752).

C. Monitoring Requirements

1. Whether a carbon adsorber is used for VOC emissions reduction or whether a thermal incinerator is used for VOC control, CHS shall comply with the appropriate monitoring as required by 40 CFR 60.695 (ARM 17.8.749 and 40 CFR Subpart QQQ).

2. CHS shall implement a Leak Detection and Repair (LDAR) program meeting 40 CFR 60 Subpart GGGa for all new components in VOC service installed as a part of the thermal combustor project system (ARM 17.8.752).

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

1. CHS shall keep records and furnish reports to the Department as required by 40 CFR 60, Subpart QQQ, for requirements not overridden by 40 CFR 63, Subpart CC.

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

Section XIX: Limitations and Conditions for Intermediate Storage Tanks 146 and 147

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tank 146, which is classified as a Group 2 storage vessel.

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

C. Limitations for Storage Tank 146 and Tank 147

1. Storage Tanks 146 and 147 shall be fixed roof tanks with submerged fill piping (ARM 17.8.752).

2. Storage Tanks 146 and 147 shall store only intermediate products with a true vapor pressure less than 0.49 actual pounds per square inch (psia) (ARM 17.8.749).

3. CHS shall comply with 40 CFR 63 Subpart CC as applicable to Tanks 146 and 147 (ARM 17.8.342 and 40 CFR 60 Subpart CC).

D. Monitoring Requirements

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

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

CHS shall calculate annual emissions from the operation of Tank 146 and Tank 147 and report these emissions with the annual emission inventory (ARM 17.8.749).

Section XX: Replacement Refinery Flare / Flare Gas Control System (Upon startup of the Replacement Refinery Flare)

A. Limitations and Standards:

1. CHS shall comply with all applicable requirements of 40 CFR 63.670 and 40 CFR 63.671, including flare design, operation, and monitoring requirements (ARM 17.8.752; 40 CFR 63.670, 40 CFR 63.671, ARM 17.8.342). The Replacement Refinery Flare shall be steam assisted (ARM 17.8.749).

2. CHS shall not flare in the Replacement Refinery Flare any gas exceeding 162 ppmv H_2S determined hourly on a 3-hour average basis. The combustion of process upset gases, as defined in 40 CFR 60 Subpart Ja, or fuel gas as defined in 40 CFR 60 Subpart Ja that is released to the flare as a result of relief valve leakage or other emergency malfunctions, is exempt from this limit (ARM 17.8.752).

3. CHS shall comply with all applicable requirements of 40 CFR 60 Subpart Ja, including requirements for a flare management plan, root cause analysis program, flow monitoring, and total reduced sulfur or H_2S monitoring (ARM

17.8.340 and 40 CFR 60 Subpart Ja). The flare management plan shall specifically discuss the operation and monitoring of the flare water seal and identify the associated backpressure it provides, and discuss maximizing use of the flare gas treatment and recovery system during planned maintenance events on the flare gas recovery system (ARM 17.8.749 and ARM 17.8.752).

4. CHS shall install and operate a Flare Gas Treatment and Recovery System which shall include three (3) GARO AB 1500 compressors or equivalent, and amine treatment capacity to ensure treatment of captured vent gases to meet NSPS Ja requirements (ARM 17.8.749, ARM 17.8.752).

5. CHS shall implement a Leak Detection and Repair (LDAR) program meeting 40 CFR 60 Subpart GGGa for all new components in VOC service installed as a part of the Replacement Refinery Flare project, including components added to recover and treat flare gas from the Zone E flare (Coker flare) system (ARM 17.8.752).

B. Monitoring and Recordkeeping:

1. CHS shall maintain onsite, and available at all times, the as-built design specifications of the flare and flare gas treatment and recovery system, such that a demonstration of compliance with design standards of 40 CFR 63.670 and 40 CFR 63.671, the Flare Gas Treatment and Recovery System design requirements, and the stack height requirement can be made. The records shall include manufacturer/vendor data as applicable (ARM 17.8.749).

2. CHS shall comply with applicable recordkeeping requirements of 40 CFR 63.670 and 40 CFR 63.671 (40 CFR 63.670, 40 CFR 63.671 and ARM 17.8.342).

3. CHS shall monitor compliance with the 162 ppmv H_2S flare gas limitation of Section XX.A.6 in accordance with the monitoring requirements provided in 40 CFR 60 Subpart Ja (ARM 17.8.749).

4. CHS shall comply with the monitoring and recordkeeping requirements outlined in 40 CFR 60 Subpart VVa except where specifically exempted in 40 CFR 60 Subpart GGGa (ARM 17.8.749).

C. Reporting:

1. CHS shall comply with the applicable reporting requirements of 40 CFR 60 Subpart Ja (ARM 17.8.340 and 40 CFR 60 Subpart Ja).

2. CHS shall submit reports to the Department as outlined in the 40 CFR 60 Subpart VVa reporting requirements incorporated by reference into 40 CFR 60 Subpart GGGa (ARM 17.8.749).

3. CHS shall comply with applicable reporting requirements of 40 CFR 63.670 and 40 CFR 63.671 (40 CFR 63.670, 40 CFR 63.671 and ARM 17.8.342.)

Section XXI: Sour Water Stripper Ammonia Combustor

A. Limitations and Standards:

1. CHS shall install and operate Selective Catalytic Reduction technology on the Ammonia Combustor to achieve NO_X emissions of no more than 61 ppmv at 3% O_2 on a 365-day rolling average basis, as measured by NO_X CEMS and calculated on each calendar day basis, applicable at all times, including startup and shutdown (ARM 17.8.752).

2. CHS shall not emit more than 1.85 lb/hr of NO_X on a rolling 24-hr average basis from the Ammonia Combustor, as measured by NO_X CEMS and stack flowrate monitor with appropriate moisture correction defined by an initial source test. The initial source test shall be completed within 180 days of startup of the ammonia combustor. This limit shall not apply during startup and shutdown of the unit when the SCR is not at its design operating temperature (ARM 17.8.749).

3. Ammonia emissions from the Ammonia Combustor shall not exceed 10 ppmv at 3% O_2 (ARM 17.8.752).

4. CHS shall not emit from the Ammonia Combustor SO_2 in excess of the following, as measured by SO_2 CEMS (ARM 17.8.752):

   a. 20 ppmv on a dry basis, corrected to 0% excess air, determined hourly on a 3-hour rolling average basis, and;

   b. SO_2 in excess of 8 ppmv on a dry basis, corrected to 0% excess air, determined daily on a 365-successive calendar day rolling average basis.

5. CHS shall not emit from the Ammonia Combustor SO_2 in excess of 0.80 lb/hr (ARM 17.8.749).

6. CHS shall comply with all applicable requirements of 40 CFR 60 Subpart Ja (ARM 17.8.340 and 40 CFR 60 Subpart Ja).

7. The Ammonia Combustor shall be operated with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours as determined by visual survey (ARM 17.8.752).

B. Monitoring and Recordkeeping:

1. CHS shall monitor compliance with the SO_2 emissions limitations of Section XXI.A.4 according to 40 CFR 60.8 and 40 CFR 60.104a, and 40 CFR 60.107a, and as otherwise described in 40 CFR 60 Subpart Ja. CHS shall comply with all applicable monitoring and recordkeeping requirements of 40 CFR 60 Subpart Ja (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

2. CHS shall perform source testing for NH_3 utilizing methodology as agreed in writing by CHS and the Department, on an every four year basis (ARM 17.8.749).

C. Reporting:

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service (or equivalent service). The report shall include the following:

   a. summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

   b. a summary report for all CEMS required by this section.

3. CHS shall report SO_2 emissions in accord with 40 CFR 60 Subpart Ja. CHS shall comply with all applicable reporting requirements of 40 CFR 60 Subpart Ja (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

Section XXII: Crude Oil Blending Project – Tanks 153 and 1821-37B – 260,000 Barrel External Floating Roof Tanks

A. Limitations and Standards:

1. CHS shall meet the equipment design and work practice standards of 40 CFR 60 Subpart Kb, as applicable to Crude Oil Storage Tanks 153 and 1821-37B (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60 Subpart Kb).

2. CHS shall comply with the requirements of 40 CFR 63 Subpart CC and 40 CFR 60 Subpart Kb as applicable to Crude Oil Storage Tanks 153 and 1821-37B (ARM 17.8.340 and 40 CFR 60 Subpart Kb; ARM 17.8.342 and 40 CFR 63 Subpart CC).

3. CHS shall implement an LDAR program equivalent to 40 CFR 60 Subpart GGGa for the refinery equipment associated with Crude Oil Storage Tanks 153 and 1821-37B (ARM 17.8.752).

B. Monitoring, Recordkeeping, and Reporting:

1. CHS shall notify the Department of startup within 30 days of startup of Crude Oil Storage Tank 1821-37B, as determined by the earlier of postmark or email date (ARM 17.8.749).

2. CHS shall comply with all applicable testing, monitoring, recordkeeping, and

reporting requirements of 40 CFR 60 Subpart Kb and 40 CFR 63 Subpart CC as applicable to Crude Oil Storage Tanks 153 and 1821-37B. (ARM 17.8.340 and 40 CFR 60 Subpart Kb, ARM 17.8.342 and 40 CFR 63 Subpart CC).

Section XXIII: Limitations and Conditions for Hydrogen Plant #3. (This equipment originated from MAQP #1821-36 originally titled as the Grassroots Hydrocracker Project since there is a multi-source limit that includes the FCCU regenerator).

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

1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

2. Subpart Ja - Standards of Performance for Petroleum Refineries applies to the Hydrogen Reformer Unit Heater (067HT0001)

3. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to Hydrogen Plant #3. The compressors in Hydrogen Plant #3 are subject to Subpart GGGa when processing Refinery Fuel Gas (RFG) or other process gases. When the unit feed is natural gas, the compressors are not considered to be in VOC service."

4. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems applies to Hydrogen Plant #3.

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, applicable components in Hydrogen Plant #3 with the potential for greater than five percent weight HAP.

3. Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters applies to the Hydrogen Reformer Unit Heater (067HT0001.)

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

D. CHS shall not exceed 879,697 tons per year total CO_2e (rolling 12-month total) from the Hydrogen Reformer Heater (067HT0001), and the FCCU (ARM 17.8.479 and

17.8.752).

E. Limitations on Individual Sources (ARM 17.8.752)

1. Hydrogen Reformer Heater (067HT0001)

   a. SO_2 emissions from 067HT0001 shall not exceed (ARM 17.8.749 and 17.8.752):

      i. 9.76 tons/12-month rolling total;

      ii. 6.0 lb/hr based on a 3-hr rolling average.

   b. CHS shall not burn any fuel gas that contains H_2S in excess of 162 ppmvd determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmvd determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Ja).

   c. The Hydrogen Reformer Heater (067HT0001) shall be equipped with low NOx burners and selective catalytic reduction; and ammonia slip shall not exceed 10 ppm average ammonia demonstrated for performance tests (ARM 17.8.749 and 17.8.752).

   d. NO_x emissions from the Hydrogen Reformer Heater (067HT0001) shall not exceed:

      i. 25.16 tons/rolling 12-calendar month total (ARM 17.8.749);

      ii. 5.62 lb/hr 365-day rolling average including startup and shutdown based on NOx CEMS (ARM 17.8.749 and 17.8.752);

      iii. 22.5 lb/hr during periods of startup, on an hourly rolling 24-hour average basis. Startup begins when fuel is first fired and startup ends when the SCR inlet reaches its required temperature and ammonia injection has been established (ARM 17.8.749 and 17.8.752).

   e. CHS shall maintain documentation of the necessary catalyst operating temperature on-site for each type of catalyst used in the SCR (ARM 17.8.749).

   f. CO emissions from the Hydrogen Reformer Heater (067HT0001) shall not exceed:

      i. 91.08 tons/rolling 12-calendar month total (ARM 17.8.749);

      ii. 20.8 lb/hr 365-day rolling average based on CO CEMS (ARM 17.8.749 and 17.8.752);

      iii. 41.6 lb/hr during periods of startup, on an hourly rolling 36-hr average basis (ARM 17.8.749 and 17.8.752).

g. VOC emissions from the Hydrogen Reformer Heater (067HT0001) shall not exceed 1.26 lb/hr based on EPA Reference Methods 18 and 25, or another methodology as agreed in writing between CHS and the Department (ARM 17.8.749 and ARM 17.8.752).

h. $PM_{10}/PM_{2.5}$ emissions from the Hydrogen Reformer Heater (067HT0001) shall not exceed 4.2 lb/hr based on EPA Reference Methods 5 or 201 and 202 (ARM 17.8.749 and 17.8.752).

i. CO_2e emissions from the Hydrogen Reformer Heater (067HT0001) shall be minimized by:

    i. Firing only PSA tailgas, RFG or pipeline quality natural gas (ARM 17.8.749 and 17.8.752);

    ii. Preventive tune-ups per 40 CFR 63 Subpart DDDDD (ARM 17.8.749, ARM 17.8.752 and 40 CFR 63 Subpart DDDDD).

j. CO, VOC and PM/PM_{10} emissions shall be controlled by proper design and good combustion practices (ARM 17.8.749 and 17.8.752).

F. Monitoring/Testing Requirements

1. CHS shall install, operate, calibrate, and maintain the following CEMS/CERMS on the Hydrogen Reformer Heater (067HT0001)

    a. NO_X (40 CFR 60, Subpart Ja)

    b. O_2 (40 CFR 60, Subpart Ja)

    c. H_2S on fuel gas systems (not individual heaters). This is not required if either natural gas or PSA tailgas are used as these fuels are exempt from Subpart Ja due to their characteristics (40 CFR 60, Subpart Ja).

    d. Stack Flow Rate (ARM 17.8.749)

2. CHS shall install, operate, calibrate, and maintain a CO CEMS/CERMS for the Hydrogen Reformer Heater (067HT0001) (ARM 17.8.749).

3. CHS shall perform source testing and/or demonstrate compliance for the Hydrogen Reformer Heater (067HT0001), for the pollutants listed below with the EPA reference methods and methodologies at the frequencies indicated:

    a. NO_X – Every three years from the date of the last source test using EPA Method 7, in conjunction with annual CEMS/CERMS RATA performance testing in accordance with Appendix F (40 CFR Part 60) requirements, or according to another testing/ monitoring schedule as may be approved by the Department, for NOx/O_2 and CO (EPA Method 10), concurrently, and the results submitted to the Department in order to demonstrate compliance with the NOx and CO emission limits (ARM 17.8.105 and ARM 17.8.749, 40 CFR 60, Subpart Ja).

b. CO – Every three years from the date of the last source test using EPA Method 10. for CO in conjunction with the annual CEMS/CERMS RATA performance testing in accordance with Appendix F (40 CFR Part 60). (ARM 17.8.749).

VOC – EPA Method 18 and 25. EPA Method 18 and 25 or another methodology as agreed between CHS and the Department, as requested by the Department (ARM 7.8.749).

c. $PM_{10}/PM_{2.5}$ – EPA Method 5 or 201 and 202. Once every 6 years or according to another testing/monitoring schedule as may be approved by the Department (ARM 7.8.749).

d. Ammonia Slip – The Hydrogen Reformer Heater shall be tested within two years of the initial source test and thereafter as requested by the Department to demonstrate compliance with the 10-ppm limit. The ammonia testing protocol shall be determined using a methodology as agreed in writing between CHS and the Department (ARM 17.8.749 and 17.8.752).

e. CO_2e Emissions – For the hydrogen reformer heater (067HT0001) compliance shall be demonstrated following the calculation procedures of 40 CFR part 98 subpart P. For the FCCU regenerator compliance shall be demonstrated following the calculation procedures of 40 CFR part 98 subpart Y for catalytic cracking units (ARM 17.8.749 and ARM 17.8.752).

4. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, Subparts Ja, 60.100a-60.108a, and Appendix B, Performance Specifications 2, 3, 6, and Appendix F; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).

5. CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, and breakdowns and repairs of CEMS related equipment. In the event the primary CEMS is unable to meet minimum availability requirements, the recipient shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated (ARM 17.8.749).

6. Compliance with the opacity limitation listed in Section XXIII.C shall be determined using EPA Reference Method 9 testing by a qualified observer (ARM 17.8.749).

G. Recordkeeping and Reporting Requirements (ARM 17.8.749)

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service (or equivalent service). The report shall include the following:

   a. summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

   b. a summary report for all CEMS required by this section.

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

Section XXIV: Asphalt Storage Tank under MAQP #1821-36 (Two tanks were originally approved but within application MAQP #1821-46, Tank B was removed as a decision was made earlier not to install Tank B.

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

   1. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS subpart listed below.

   2. Subpart UU - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture.

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

   1. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.

   2. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries applies to Storage Tank 152 which is classified as a Group 2 storage vessel.

C. Within 60 days after achieving the maximum production rate at which the storage tank will operate but no later than 180 days after initial startup, CHS shall not discharge into the atmosphere from Tank 152 exhaust gases with opacity greater than zero percent opacity except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for cleaning (40 CFR Part 60, Subpart UU, ARM 17.8.749 and ARM 17.8.340).

D. Limitations for Asphalt Storage Tank 152

1. Storage Tank 152 shall be a fixed roof tank, utilize submerged fill piping and are permitted to operate with steam coils (ARM 17.8.752).

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

E. Monitoring and Reporting Requirements

VOC emissions from Storage Tank 152 shall be calculated and monitored utilizing the AP42 calculation methods (ARM 17.8.749).

F. Notification Requirements (ARM 17.8.749)

CHS shall provide the Department written notification of startup of the asphalt tank within 15 days of startup, as determined by the earlier of postmark or email date.

Section XXV: New #2 CU Vacuum Heater (005HT0002) as part of the MUE Project. This section covers the , applicable requirements and permit conditions which were permitted under MAQP #1821-43 and modified under MAQP #1821-46 with the removal of H-7502 and Boiler #13.

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 GGG -Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced after January 4, 1983, and on or Before November 7, 2006. The MUE Project does not result in additional applicability to subpart GGG. The #2 Crude Unit, DCU and NHT were already subject to subpart GGG requirements and is noted here for information purposes.

3. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006. The MUE Project does not result in additional applicability to subpart GGGa. The MHC and RFG piping to the refinery steam generating boilers were already subject to the subpart GGGa requirements and is noted here for information purposes.

4. Subpart Ja - Standards of Performance for Petroleum Refineries applies to the #2 CU Vacuum Heater, as applicable. The #2 CU Vacuum Heater (05H0002) is subject to the fuel gas H_2S requirements and not the NOx requirements.

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 affected sources or the collection of emission points as defined in this subpart.

   3. Subpart DDDDD - National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters applies to the new #2 CU Vacuum 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 6 consecutive minutes (ARM 17.8.304 (2)).

D. CEMS and CERMS required by this permit shall comply with all applicable provisions of 40 CFR Parts 60.5 through 60.13, NSPS Subparts Ja and Db and Appendix B, Performance Specifications 2, 3, 6, and Appendix F; and 40 CFR 52, Appendix E, for certifying Volumetric Flow Rate Monitors (ARM 17.8.749).

E. Limitations on Individual Sources (ARM 17.8.752)

   1. New #2 CU Vacuum Heater (005HT0002)

      a. CHS shall not burn any fuel gas that contains H_2S in excess of 162 ppmvd determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmvd determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Ja).

      b. The #2 CU Vacuum Heater (005HT0002) shall be equipped with ultra-low NOx burners and NOx emissions not exceed 1.05 lb/hr (ARM 17.8.749 and 17.8.752).

      c. CO emissions from the #2 CU Vacuum Heater (005HT0002) shall be minimized by utilizing proper design and good combustion practices, and not exceed 1.05 lb/hr as demonstrated with EPA Federal Reference Method 10 (ARM 17.8.752).

      d. VOC emission from the #2 CU Vacuum Heater (005HT0002) shall be minimized by utilizing proper design and good combustion practices, and shall be demonstrated by compliance with the CO emission limit and completion of the preventive tune-ups required per 40 CFR 63 Subpart DDDDD (ARM 17.8.749, ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).

      e. CHS shall utilize proper design and good combustion practices and complete the preventative tune-ups required by 40 CFR 63 Subpart DDDDD to minimize $PM_{10}/PM_{2.5}$ emissions at the #2 CU Vacuum

Heater (005HT0002). (ARM 17.8.749, ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).

f. CO_2e emissions from the #2 CU Vacuum Heater (005HT0002) shall be minimized by:

   i. Firing only RFG or pipeline quality natural gas (ARM 17.8.749 and 17.8.752);

   ii. Completing preventive tune-ups per 40 CFR 63 Subpart DDDDD (ARM 17.8.749, ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).

g. NOx emissions from the #2 CU Vacuum Heater shall not exceed 4.59 tons per rolling 12-calendar month total;

h. SO_2 emissions from the #2 CU Vacuum Heater shall not exceed 0.84 tons per rolling 12-calendar month total

i. CO emissions from the #2 CU Vacuum Heater shall not exceed 4.59 tons per rolling 12-calendar month total

F. #2 CU Vacuum Heater Monitoring/Testing Requirements

1. Compliance for the #2 CU Vacuum Heater H_2S limit in Section XXV.E.1.a shall be demonstrated using a CEMS on the fuel gas supply unless exempted by 40 CFR 60.107(a)(3) (ARM 17.8.106, ARM 17.8.340 and 40 CFR 60 Subpart Ja).

2. Compliance for the #2 CU Vacuum Heater NOx limit in Section XXV.E.1.b shall be demonstrated using Federal Reference Method 7E. Initial testing shall be conducted within 180 days of startup, concurrently with CO testing, and every 3 years thereafter or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.749 and ARM 17.8.106).

3. Compliance for the #2 CU Vacuum Heater CO limit in Section XXV.E.1.c shall be demonstrated using Federal Reference Method 10. Initial testing shall be conducted within 180 days of startup, concurrently with NOx testing, and every 3 years thereafter using the date of the last source test or according to another testing/monitoring schedule as may be approved by the Department (ARM (ARM 17.8.749 and ARM 17.8.106).

4. Compliance for the #2 CU Vacuum Heater VOC condition in Section XXV.E.1.d shall be demonstrated by compliance with the CO limit and the recordkeeping required by 40 CFR 63 Subpart DDDDD (ARM 17.8.752, ARM 17.8.106 and 40 CFR 63 Subpart DDDDD).

5. Compliance for the #2 CU Vacuum Heater $PM_{10}/PM_{2.5}$ condition in Section XXV.E.1.e shall be demonstrated via the recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.752, ARM 17.8.106, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).

6. Compliance for the #2 CU Vacuum Heater CO_2e condition in Section XXV.E.1.f shall be demonstrated via the recordkeeping requirements of 40 CFR 63 Subpart DDDDD (ARM 17.8.752, ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).

G. LDAR Program for Equipment Leaks - #2 Crude Unit, DCU and NHT

CHS shall develop an effective LDAR program meeting the requirements of NSPS subpart GGGa for the #2 Crude Unit, DCU and NHT process units (ARM 17.8.752).

H. Wastewater Collection VOC for MHC and #2 Crude Unit Modifications

CHS shall develop n effective monitoring program meeting the requirements of NSPS subpart QQQ standard applicable to new and modified individual drain systems for the #2 crude unit, and applicable to individual drain systems in the MHC (ARM 17.8.752).

I. Recordkeeping and Reporting Requirements

1. CHS shall maintain the records required to demonstrate compliance with the limitations and conditions in this section. The records shall be made available upon request by the Department.

2. CHS shall prepare and submit a quarterly emission report within 30 days of the end of each reporting period. The reports shall be submitted electronically to the Helena Air Quality Bureau's Administrative email address, or up-loaded to the State of Montana's File Transfer Service using the Air Quality Bureau's Administrative email address as the recipient (or equivalent service). The report shall include the following:

   a. summary of deviations from permit limits and conditions which occurred during the reporting period. If not previously provided, the report should include the reasons for occurrence, mitigative measures utilized and corrective actions taken to prevent recurrence of the event. If previously provided, the summary shall include the date the report was submitted.

   b. a summary report for all CEMS required by this section.

J. Notification Requirements

CHS shall notify the Department within 30 days of startup of the #2 CU Vacuum Heater as determined by the earlier of the postmark date or email sent date (ARM 17.8.749).

Section XXVI: General Conditions

A. Inspection - CHS shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (Continuous Emissions Monitoring System (CEMS), Continuous Emissions Rate Monitoring System

(CERMS)) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver - The permit and all the terms, conditions, and matters stated herein shall be deemed accepted if CHS fails to appeal as indicated below.

C. Compliance with Statutes and Regulations - Nothing in this permit shall be construed as relieving CHS of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*. (ARM 17.8.756).

D. Enforcement - Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement as specified in Section 75-2-401 *et seq*., MCA.

E. Appeals - Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

F. Permit Inspection - As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by Department personnel at the location of the permitted source.

G. Duration of Permit - Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762).

H. Permit Fees - Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, failure to pay the annual operation fee by CHS may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

ATTACHMENT A

Refinery Limitations and Conditions associated with MAQP #1821-05 Compliance Determination

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.

      ii. 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. CHS is no longer combusting fuel oil so this condition no longer applies but is being left in place as it was established as part of MAQP #1821-05. References to fuel oil combustion were removed from the permit as part of MAQP #1821-41.

   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: Sulfur content and specific gravity of alkylation unit polymer pursuant to Appendix G of the CHS Consent Decree.

3. Gas fired internal combustion

   a. SO_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

Calculation Basis: AP-42 Section 3-2 (10/96 revision)
Key Parameters: Monthly fuel use (scf) per combustion unit and monthly average fuel gas heat content.

4. Zone D (H-101, H-201 and H-202)

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 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 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 stack tests for sources burning refinery fuel gas. For sources firing only natural gas, the most current VOC stack test will be used to develop emission factors.

ii. Key Parameters: VOC stack test.

5. Fugitive equipment leaks

a. SO_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.

6. Boiler #10

   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: NO_x and O_2 CEMS, Volumetric stack flow rate monitor, Emission factors based on stack tests.

      ii. Key Parameters: NO_x and O_2 CEMS, Reference Method 19, NO_x stack tests, monthly fuel use (scf), volumetric stack flow rate.

   c. CO

      i. Calculation Basis: CO and O_2 CEMS, 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).

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.

c. CO

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

d. PM_{10}/PM

   i. Calculation Basis: Results from stack tests.

   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 stack tests.

      ii. Key Parameters: 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 stack tests.

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

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

10. 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).

11. Cooling towers

   a. SO_2, NO_x, CO: Not applicable – not a source

   b. PM_{10}/PM: Cooling tower design (Delayed coker unit cooling tower applicable)

   c. VOC

      i. Calculation Basis: AP-42, Section 5.1 (1/95 rev.).

      ii. Key Parameters: Monthly cooling tower circulation (gal).

12. 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.).

13. Storage tanks

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

b. VOC

   i. Calculation Basis: actual emission, AP-42 calculation methods and other reasonable sources as outlined in the application for MAQP #1821-27.

   ii. Key Parameters: Monthly volume of material throughput from yield accounting, material property data (VP, MW, etc.).

Montana Air Quality Permit (MAQP) Analysis
CHS Inc. – Laurel Refinery
MAQP #1821-46

I. Introduction/Process Description

A. Site Location/Description

The CHS Inc. (CHS) Laurel Refinery is a petroleum refinery located in the South ½ of Section 16, Range 24 East, Township 2 South, in Yellowstone County. A complete list of permitted equipment is available in the permit. The source categories for the refinery limitations and conditions associated with MAQP #1821-05 are listed below.

With the issuance of MAQP #1821-05, CHS requested to place enforceable limits on future 'site-wide' emissions for the collective units that were in operation at the facility at this time. Although modifications (including removal and addition of various emitting units) have occurred at the facility since these limitations were put in place, the following collective units identified at the time of issuance of MAQP #1821-05 continue to be subject to the limitations and conditions within the permit:

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

   a. #1 crude heater, crude preheater, #1 crude vacuum heater

   b. #2 crude heater, #2 crude vacuum heater

   c. Alkylation Unit hot oil belt heater

   d. Platformer Heater (P-HTR-1), platformer debutanizer heater

   e. Fluid Catalytic Cracking (FCC) Charge Heater (FCC-Heater-1) (Replaced with FCC-Charge Heater (FCC-Heater NEW)

   f. NHT Reboiler Heater #1 (H-8302), NHT Reboiler Heater #2 (H-8303), and NHT Splitter Reboiler (H-8304), #2 NU Heater (shutdown as part of MAQP #1821-13), MDU Stripper Heater (Shutdown as a part of MAQP #1821-09 and modified and re-permitted as part of MAQP #1821-13, Currently Naphtha Hydrotreater (NHT) Charge Heater (H-8301)), PDA Heater (Shutdown as a part of MAQP #1821-13)

   g. Zone D Hydrogen Plant Reformer Heater (H-101), Reactor Charge Heater (H-201), Fractionator Feed Heater (H-202)

   h. Asphalt Loading Heater #1

   i. #1 fuel oil heater, #60 tank heater

   j. Boiler #9, Boiler #10, Boiler #11, and Boiler #12 (Boilers #11 and #12 were replacement boilers following shutdown and removal of #3, #4, and #5 boilers)

2. Fuel oil-fired external combustion sources, includes: #3 boiler (Shutdown and removed as part of MAQP #1821-15), #4 boiler (Shutdown and removed as part of MAQP #1821-22), #5 boiler (#5 boiler shutdown and removed as part of MAQP #1821-22), CO Boiler (Shutdown and removed as part of MAQP #1821-15);

3. Gas-fired internal combustion source includes: Platformer recycle turbine, Zone D compressor gas engine (C-201B) (Shutdown as part of MAQP #1821-23), #1-4 unifier compressors (Shutdown with ULSD and coker projects);

4. FCC unit (FCCU) Regenerator;

5. Zone A Sulfur Recovery Unit (SRU) Tail Gas Incinerator (TGI, SRU-INC-22);

6. Zone D SRU Incinerator;

7. Delayed Coker Unit: Zone E SRU/Tail Gas Incinerator Treatment Unit (TGTU)/TGI;

8. Fugitive equipment leaks include all equipment, as defined in 40 Code of Federal Regulations (CFR) 60, Subpart VV, in hydrocarbon service;

9. Wastewater facilities;

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

11. Loading facilities: light product truck rack and vapor combustion unit (VCU), heavy oil truck rack, and heavy oil rail rack; and

12. Storage tanks: tank numbers 2, 7, 9 (Replaced with Tank 127), 12, 28 (Replaced with Tank 126), 41, 47, 56, 60, 61, 62, 63, 65 (Replaced with Tank 144), 66, 67 (Replaced with Tank 145), 68, 70, 73, 74, 75, 76, 77, 78, 79, 80, 81, 82, 83, 85, 86, 88, 91, 92, 93, 94, 95, 96, 100, 101, 102, 103, 104, 108, 109, 110, 111, 112, 113, 114, 117, 118, 120, 121, 122, 123, 126 (Replaced Tank 28), 127 (Replaced Tank 9), B-1, B-2, B-7, firetk 2, firetk 3, and firetk 4.

B. Permit History

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

The hydrodesulfurization (HDS) process is utilized to pretreat Fluid Catalytic Cracking Unit (FCCU) feeds by removing metal, nitrogen, and sulfur compounds from these feeds. The proposed HDS unit also improved the quality of refinery finished products including gasoline, kerosene, and diesel fuel. The HDS project significantly improved the finished product quality by reducing the overall sulfur contents of liquid products from the Cenex Refinery. The HDS unit provided low sulfur gas-oil feedstocks for the FCCU, which resulted in major reductions of sulfur oxide emissions to the atmosphere. However, only a minor quantity of the proposed sulfur dioxide (SO_2) emission reductions was made federally enforceable.

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

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

The basis for the permit application was due to a net contemporaneous emissions increase that was less than the significant level of 40 tons per year (TPY) for SO_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.

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

Cenex has also requested a permit alteration to remove the SO_2 emission limits for the C-201B compressor engine because the permit already limits C-201B to be fired on either natural gas or unodorized propane. Cenex also requested that if the SO_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. MAQP #1821-01 requires that compliance with the hourly (lb/hr) emission limits be determined through annual source testing and that the daily (lb/day), annual (ton/yr), and Administrative Rules of Montana (ARM) 17.8 Subchapter 8 requirements (i.e., PSD significant levels and review) be determined by using actual fuel burning rates and the manufacturer's guaranteed emission factors listed in Attachment B. Cenex has requested to use actual fuel burning rates and fixed emission factors determined from previous source test data in order to determine compliance with the daily (lb/day) and annual (ton/yr) emission limits. The Department agrees that actual stack testing data is preferred to manufacturer's data for the development of emission factors. However, the Department is requiring that the emission factor be developed from the most recent source test and not on an average of previous source tests. The permit has been changed to remove Attachment B and rely on emission factors derived from the most recent source test, along with actual fuel flow rates for compliance determinations. However, in order to determine compliance with ARM 17.8 Subchapter 8, Cenex shall continue to monitor the fuel gas flow rates in both scf/hr and scf/year.

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

The following emission limitations were modified by this permit.

Source	Pollutant	Previous Limit	New Limit
SRU Incinerator stack (E-407 & INC-401)	SO_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
	SO_2	0.214 lb/hr	1.716 lb/hr

Source	Pollutant	Previous Limit	New Limit
Reactor Charge Heater (H-201)		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
	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 particulate matter with an aerodynamic diameter of 10 microns or less (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 Carbon Monoxide (CO) by 4.7 tons per year and 60 tons per year, respectively. Because of the offsets provided by reducing emissions from the old SWS, this permitting action will not increase allowable emissions of SO_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 have been revised to ensure that the required offsets are provided without putting Cenex in a non-compliance situation at issuance of the permit. The compliance determinations and the reporting requirements were also changed to reflect this requirement.

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

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

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

Numbering has been changed in Section III.

MAQP #1821-04 was issued to Cenex on March 6, 1998, in order to comply with the gasoline loading rack provisions of 40 CFR 63, Subpart CC – National Emission Standards for Petroleum Refineries, by August 18, 1998. Cenex proposed to install a gasoline vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAPs) resulting from the loading of gasoline. A vapor combustion unit (VCU) was added to the product loading rack. The gasoline vapors would be collected from the trucks during loading, then routed to an enclosed flare where combustion would occur. The result of this project would be an overall reduction in the amount of VOCs (503.7 TPY) and HAPs emitted, but CO and NO_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 Department identified the following HAPs from the flare, which were used in the health risk assessment. These constituents are typical components of Cenex's gasoline:

1. Benzene
2. Toluene
3. Ethyl Benzene
4. Xylenes
5. Hexane
6. 2,2,4 Trimethlypentane
7. Cumene
8. Naphthalene
9. Biphenyl

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

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

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

The site-wide limits were calculated based on the addition of the PSD/NAA significance level for each particular pollutant to the actual refinery emissions from April 1998, through March 2000, for SO_2, NO_x, CO, PM_{10}, and particulate matter (PM) minus 0.1 TPY to remain below the significance level. A similar methodology was used for the VOC emissions cap, except that baseline data from the time periods 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.
MAQP#1821-05 replaced MAQP #1821-04.

MAQP #1821-06 was issued on April 26, 2001, for the installation and operation of eight temporary, portable Genertek reciprocating engine electricity generators and two accompanying distillate fuel storage tanks. Each generator is capable of generating approximately 2.5 megawatts of power. These generators are necessary because of the high cost of electricity. The operation of the generators will not occur beyond two years and is not expected to last for an extended period of time, but rather only for the length of time necessary for Cenex to acquire a more economical supply of power.

Because these generators would only be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of these generators is minor. In addition, the installation of these generators qualifies as a "temporary source" under the PSD permitting program because the permit will limit the operation of these generators to a time period of less than 2 years. Therefore, Cenex would not need to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, the Department required compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 would be ensured. In addition, Cenex would be responsible for complying with all applicable air quality standards. In order to keep this permitting action below the threshold of nonattainment area permitting requirements, Cenex requested a limitation to keep the project's potential emissions of SO_2 below 40 tons. MAQP #1821-06 replaced MAQP #1821-05.

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

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

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

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

On July 30, 2003, the Department received a complete application from CHS to modify MAQP #1821-09. The application was complete with the addition of modeling information provided to the Department on August 22, 2003. CHS requested to add a new TGTU and associated equipment for Zone A's SRU #1 and SRU #2 trains to control and reduce SO_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. **MAQP #1821-10** replaced MAQP #1821-09.

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

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

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

The net emission changes were as follows:

Pollutant	Total Project PTE (TPY)	Contemporaneous Emission Changes (TPY)	Net Emissions Change (TPY)	PSD Significance Level (TPY)
NO_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). MAQP #1821-13 replaced MAQP #1821-12.

On May 4, 2006, the Department received a complete application from CHS to incorporate the final design of three emission sources associated with the new 15,000 BPD delayed coker unit project permitted under MAQP #1821-13. The final design capacities have increased for the new NHT Charge Heater, the new Coker Charge Heater and the new Boiler No. 11. The application also includes a request to reduce the refinery-wide fuel oil burning SO_2 emission limitation. This reduction allows CHS to stay below the significance threshold for the applicability of the New Source Review-PSD program. The maximum firing rates are proposed to increase with the current permitting action. The following summarizes the originally permitted firing rates (MAQP #1821-13) and the new proposed firing rates for the heaters and the boiler:

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

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

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

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

The Department agreed that the heading to Section X.A.3 can include the "*Naphtha Hydrotreating Unit*"; Section D.1.c is based on a 30-day rolling average; Section X.D.7.a.ii should state that the SO_2 limit is based on a 12-hour average; and that Section XI.E.3 should be revised to remove the requirement for a stack gas volumetric flow rate monitor. The Department made some clarifications to the language in Section X.D.6.b. The Department's intent in permitting the coke pile with enclosures was to ensure that at no time would the coke pile be higher than the top of the enclosure walls at any point on the pile, not only the portion of the pile that is adjacent to the wall.

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

The Department received comments from CHS on the preliminary determination of MAQP #1821-14 on June 21, 2006. The comments were editorial in nature and the changes were made prior to issuance of the Department Determination on MAQP #1821-14. CHS requested corrections to the PM, PM_{10}, NO_x netting values in contained in the permit analysis, and the Department agreed that the edits were needed. CHS also requested further clarification to the requirements of Section X.D.6.b of the permit.

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

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

- Retaining Boiler #4 operations and permanently shutting down the CO Boiler;
- Modifying the FCCU Regenerator CO limit due to the air grid replacement;
- Rescinding the permitted debottleneck project for Zone D SRU/TGTU/TGI and revising the long term SO_2 potential to emit;
- Modifying the Zone E (Delayed Coker) SRU/TGTU/TGI - Incinerator design and NO_x limits;
- Rescinding the firing rate restriction and associated long-term emission limits, and revising VOC emission calculations for H-201 and H-202; and
- Removing the 99.9 MMBtu/hr restriction and reclassifying Boiler #10 as subject to NSPS Subpart Db.

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

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

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

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

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

This change does not impact any of the other design conditions in the original delayed coker permit, including unit throughputs and operating rates. The application also includes a request to reduce the refinery-wide fuel oil burning SO_2 emission limitation. This reduction allows CHS to stay below the significance thresholds for the applicability of the New Source Review-PSD program. CHS also requested some administrative changes to the permit. **MAQP #1821-16** replaced MAQP #1821-15.

On February 25, 2008, the Department received a complete application from CHS to modify MAQP #1821-16 for the completion of two separate projects. For the first project, CHS proposed to construct a new 209.1 MMBtu-HHV/hr steam generating boiler (Boiler #12). This project includes the permanent shutdown of two existing boilers, Boilers #4 and #5, which have a combined capacity of 190 MMBtu-LHV/hr. The two existing boilers are being shut down in part to meet the consent decree NO_x reduction requirements, as well as to generate NO_x offsets for this permitting action.[1] Due to the operational complexity of replacing two existing boilers with one new boiler in the refinery steam system, CHS requested to maintain the ability to operate the #5 Boiler for 1 year after initial start-up of Boiler #12. Combustion of fuel oil in the refinery boilers would also be eliminated primarily to generate NO_x offsets for this permitting action.

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

The application also included a request to reduce the limitation for SO_2 emissions from the combustion of alkylation unit polymer and fuel oil in all combustion devices from 127.6 TPY to 50 TPY (for alkylation unit polymer only since fuel oil combustion in refinery boilers will be eliminated). Although the potential to emit for the combustion of alkylation unit polymer in the Alkylation Unit Hot Oil Heater is estimated to be around 8.3 TPY for SO_2 (based on a specific gravity of 0.7 and a sulfur content of 1 wt%; the exact potential to emit has not been determined due to the variability of specific gravity and sulfur content), the allowable emissions are set at 50 TPY in this permitting action. According to ARM 17.8.801(24)(f), the decrease in actual emissions from the elimination of fuel oil combustion in refinery boilers is creditable for PSD purposes provided the old level of actual emission or the old level of allowable emissions, *whichever is lower*, exceeds the new level of actual emissions and the decrease in emissions is federally enforceable at and after the time that actual construction begins. Since the old level of actual emissions is lower than the old level of allowable emissions for combustion of fuel oil in refinery boilers, CHS requested a creditable reduction based on actual emissions from the boilers. This reduction resulted in a total of 50 TPY SO_2 allowed for the combustion of alkylation unit polymer in the Alkylation Unit Hot Oil Heater, the only unit that is part of the original SO_2 limitation for fuel oil combustion devices that will continue to operate. While it appears that the emissions from the combustion of alkylation unit polymer would be allowed to increase through this permitting action, it is important to note that physical modifications and/or changes in the method of operation would first have to occur for the Alkylation Unit Hot Oil Heater to emit more than its estimated potential of 8.3 TPY (note: the exact potential to emit has not been determined at this time). As acknowledged by CHS, a modification and/or change in method of operation to this unit would require a permit modification.

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[1] This is later clarified in the permit history for MAQP #1821-21. No creditable NOx emissions reductions from the shutdown of Boiler #4 and #5 were used in the permit for construction of new Boiler #12 (MAQP #1821-17).

Therefore, the Department does not anticipate any increase in actual emissions from this unit, even though the allowable has been set at 50 TPY. In addition, should CHS eliminate or reduce the combustion of alkylation unit polymer in future permit actions in order to have a creditable decrease for PSD purposes, only the change in actual emissions would be available since the actual emissions will be lower than the allowable, unless a modification to the unit is made.

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

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

On April 1, 2008, CHS requested that the Department delay issuance of the preliminary determination for this permit application until additional information could be submitted regarding alternative coke handling practices. This additional information was submitted to the Department on April 3, 2008, with follow-up information received by the Department on April 14, 2008. CHS requested that an alternative coke handling process be included in MAQP #1821-17. The coke handling process, originally permitted as part of the delayed coker project, included the use of conveyors to transport coke to a crusher and to a railcar loading system. Because the system is enclosed, it is not possible to transport coke to the crusher and loading system without the use of the conveyors. CHS has since identified the need for an alternate coke handling method to be used when the conveyors are out of operation for either planned or unplanned maintenance. MAQP #1821-17 replaced MAQP #1821-16.

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

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

In this application, CHS also requested to make enforceable the retrofit of the Platformer Heater with low NO_x burners. This modification is being done to achieve Consent Decree required NO_x reductions. This modification is not required by the Benzene Reduction project; however, the retrofit of the Platformer Heater will occur during the construction phase of the Benzene Reduction project.[2]

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

In addition to making the requested changes, the Department has clarified the permit language for the bulk loading rack VCU regarding the products that may be loaded in the event the VCU is inoperable and deleted all references to 40 CFR 63, Subpart DDDDD: NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters, as it was removed from the ARM in October 2008. **MAQP #1821-18** replaced MAQP #1821-17.

On February 27, 2009, the Department received a complete MAQP application from CHS requesting clarification of an existing NO_x emissions limit for Boiler #12. In this application, CHS requested that the averaging period for the NO_x pound per million British thermal unit (lb/MMBtu) limit be specified as a 365-day rolling average. CHS submitted information to support this averaging period as the original basis for the BACT analysis conducted in MAQP #1821-17 for Boiler #12. **MAQP #1821-19** replaced MAQP #1821-18.

On August 13, 2009, the Department received a complete application from CHS requesting a modification to MAQP #1821-19. CHS proposed to retrofit the existing Boiler #10 with a lower NO_x control technology burner and to update the permit limits for this unit accordingly. This project was completed on a voluntary basis by CHS in order to improve environmental performance and boiler reliability.
On September 17, 2009, the Department received a revision to this application addressing the SO_2 BACT analysis for both Boiler #10 and the recently permitted

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[2] The requirement to retrofit the Platformer Heater with low NOx burners was removed in MAQP #1821-21. CHS elected to achieve the Consent Decree required NOx reductions by using projects other than the Platformer Heater retrofit.

Platformer Splitter Reboiler. This application revision was submitted in consultation with the Department and revised the SO_2 BACT analysis to reflect the recently finalized NSPS Subpart Ja requirements. **MAQP #1821-20** replaced MAQP #1821-19.

On March 31, 2010, the Department received an application from CHS requesting a modification to MAQP #1821-20. Additional information was received on April 22, 2010, resulting in a complete application. The application and additional information included requests for several modifications within the permit.
During the issuance of MAQP #1821-17, it became apparent that the Department and CHS had differing interpretations of paragraphs 177 and 180 of the CHS Consent Decree (CD) with EPA and the State of Montana (Consent Decree CV-03-153-BLG-RFC). Based on these differing interpretations, CHS deemed it necessary to retroactively analyze previous permit actions, particularly associated with the Delayed Coker Project, where changes may be necessary as a result of interpreting the CD in an alternative manner. On October 26, 2009, CHS provided an analysis concluding that the Delayed Coker Project was properly permitted as a non-major modification under New Source Review (including both PSD and Non-attainment Area New Source Review (NNSR)). For four pollutants (CO, VOC, TSP, and PM_{10}), project related emissions increases determined under Step 1 of the required applicability analysis were below the applicable significance thresholds. For two pollutants (NOx and SO_2), the net emissions change, including project related emissions increases and contemporaneous emissions changes, were below the applicability significance thresholds. Following review, the Department concurred with CHS' analysis. However, as a result of this re-examination, including updates and changes to the original Delayed Coker Project emissions calculations, the following updates to MAQP #1821-20 were necessary to accurately reflect the refinery's overall process and individual emitting units.

1. Coke Drum Steam Vent

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

2. FCCU Regenerator

   As part of the CD requirements, CHS completed catalyst additive trials at the FCCU in order to reduce NO_x emissions. Upon completion of the trials, CHS proposed short term (7-day rolling average) and long term (365-day rolling average) concentration-based NO_x limits to EPA. CHS proposed a long-term concentration limit of 65.1 parts per million, volumetric dry (ppm_{vd}) on a 365-day rolling average basis and a short-term concentration limit of 102 ppm_{vd} on a 7-day rolling average basis. EPA has agreed to these proposed limitations and these limits have been included within MAQP #1821-21.

3. Boiler 12 and Railcar Light Product Loading Projects

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

4. Shutdown Timing for #4 and #5 Boilers

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

5. Benzene Reduction Unit Project Updates

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

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

The original BACT analyses included in the permit applications associated with Boiler #11 and Boiler #12 did not specifically address CO emissions during startup and shutdown operations. During these operations, the boiler may experience an increase in CO emissions as a result of the ultra-low nitrogen oxide (NOx) burner (ULNB) design. Based on an analysis of data collected during startup and shutdown operations for Boiler #11 and Boiler #12, a short-term CO limit of 23 lb/hr on a 24-hour average basis, was included for periods of boiler startup and shutdown. Additionally, CHS proposed installation and operation of a volumetric stack flow rate monitor on Boiler #11 in order to be consistent with Boilers #10 and #12.

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

On July 27, 2010, the Department received a request to administratively amend MAQP #1821-21. The Department had inadvertently failed to modify all pertinent sections within MAQP #1821-20 to reflect the December 31, 2011, shutdown date for Boiler #4 and Boiler #5. CHS had requested the Department to administratively amend the permit to reflect this shutdown date in all applicable sections within the permit. CHS also requested the Department administratively amend the permit to include a reference to ppm_{vd} units where H_2S limits are expressed in grains per dry standard cubic feet (gr/dscf). The Department made the aforementioned administrative changes. **MAQP #1821-22** replaced MAQP #1821-21.
On November 1, 2010, the Department received an application from CHS requesting a modification to MAQP #1821-22.

“Mild Hydrocracker Project”

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

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

- As a result of a significant increase in hydrogen consumption, modifications to the existing hydrogen supply and recycle system will be required. The existing C-201B gas-fired reciprocating engine and hydrogen recycle compressor will be replaced with an electric driven make-up hydrogen compressor. Additionally, a new electric-driven recycle compressor (C-203) will be added.

- The first two reactors will continue to contain a hydrotreating catalyst. The third reactor will be split from one bed of catalyst to two beds of catalyst, containing both hydrotreating and hydrocracking catalyst.

- Equipment to be added or modified as a result of volume or heat impacts include the following:

- A hydrogen bypass line will be added to allow for hydrogen addition both upstream and downstream of the H-201 Reactor Charge Heater.

- Changes in the separation process downstream of the reactors: Two new drums will be added, Hot and Cold Low-Pressure Separators, along with additional heat exchange, including two sets of process heat exchangers, one cooling water heat exchanger and one fin-fan cooler.

- Trays within the H_2S Stripper will be replaced with higher capacity trays.

- The overhead condenser and pump associated with the H_2S Stripper Overhead Drum will be modified.

- A new "wild" naphtha product draw will be added to the H_2S Stripper Overhead Drum. This stream will be processed in the Crude Unit Naphtha Stabilizer and then routed to the NHT Unit.

- A bypass line for hydrocarbon feed to the Fractionator around the H-202 Fractionator Feed Heater may be added as a result of improved heat integration.

- The trays in the Fractionator will be replaced with higher capacity trays.

- A new flow loop on the Fractionator will be added returning a portion of the diesel draw to the Fractionator. The pump will also feed the Diesel Stripper. The loop will include a new pump, a fin-fan cooler and a steam generator.

- The trays in the existing Diesel Stripper will be replaced with higher capacity trays.

- New larger pump(s) will be added on the loop between the Diesel Stripper and the Diesel Reboiler. These pump(s) may also be used for diesel product.

- The Diesel Product Cooler (fin-fan) will be replaced with a higher capacity cooler.

- New higher capacity packing will be installed in the HP Absorber. Water circulation on the absorber will be eliminated.

Within the SRU, the following physical changes were proposed:

- Replace and upgrade the acid gas burner;

- Replace the reaction furnace and upgrade to higher pressure and temperature capability;

- Replace and upgrade the waste heat boiler for higher pressure steam generation;

- Replace and upgrade the three steam reheaters;

- Upgrade the #1 sulfur condenser; and

- Add new electric boiler feedwater pumps to accommodate the higher pressure steam generation.

Within the TGTU, the following physical changes were proposed:

- The trays in the quench tower and amine absorber will be replaced with higher vapor capacity trays;

- The cooling system will be improved through increased circulation and minor piping modifications to control the maximum temperature of the circulating amine; and

- The methyl diethanolamine amine (MDEA) used in the absorption section of the TGTU will be replaced with a proprietary high performance amine blend.

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

- A new H-102 Reformer Heater will be added to operate in parallel with the existing H-101 Reformer Heater;

- Modification of existing BFW pumps for increased capacity and a new larger condensate cooler;

- Addition of new pumps to circulate water through the steam generation coil on the new reformer heater;

- Modification of the existing steam drum internals to handle higher steam loads;

- Replace end of life trays within the deaerator tower with higher capacity trays;

- Replace the hot and cold condensate drums with upgraded internals and more corrosion resistant metallurgy;

- Replace absorbent and valves on the PSA skid; and

- Remove equipment related to the use of propane as the feed stream to the 100 Unit Hydrogen Plant.

“FCCU Charge Heater-NEW”

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

<u>"ULSD Burner Fuel Project"</u>

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

In addition to the aforementioned projects, CHS requested the Department to incorporate several administrative changes. **MAQP #1821-23** replaced MAQP #1821-22.

On January 10, 2011, the Department received a request to administratively amend MAQP #1821-23. In review of the Department Decision for MAQP #1821-23 issued on December 30, 2010, CHS identified areas within the permit that required further clarification based on their comments submitted on the Preliminary Determination issued for MAQP #1821-23. **MAQP #1821-24** replaced MAQP #1821-23.

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

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

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

Within the April 12, 2011, application, CHS also provided supplemental information to the BACT analysis included in the original permitting application for the Coker Charge Heater (H-7501) originally permitted as a part of the Delayed Coker project (1821-13 with revisions 1821-14 through 1821-16). This supplemental information was submitted with the purpose of laying the foundation for a proposed additional short-term CO emissions limit. **MAQP #1821-25** replaced MAQP #1821-24.

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

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

The application also included the following:

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

<u>#1 Crude Unit Revamp Project</u>

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

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

- Improvements to the preheat exchanger trains to ensure additional heat can be added to the crude oil upstream of the atmospheric column.
- Modifications to the atmospheric column from the diesel draw downward and to the associated condensing systems.
- Existing dry vacuum process will be changed to a wet vacuum system through the addition of steam.

- Redesign and replacement of the existing vacuum column.
- Installation of new equipment to recover a diesel stream from the new vacuum column.
- Addition, replacement and/or redesign of overhead and product cooling systems.

Wastewater Facilities Project

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

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

Product Blending Project

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

Additional Permit Changes

CHS conducted a review of regulatory applicability pertaining to sour water storage tanks 128 and 129, which were permitted as a result of CHS's permit application submitted on October 18, 2005, for the delayed coker project. Based on the review, CHS determined Tanks 128 and 129 to not be subject to 40 CFR 60 (NSPS) and also determined Tanks 128 and 129 to be labeled as Group 2 storage vessels as described within 40 CFR 63, Subpart CC. Therefore, CHS requested the permit, specifically the Title V Operating Permit, be updated to reflect these new determinations of regulatory applicability.

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

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

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

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

CHS also requested several various administrative changes and clarification additions.

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

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

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

Benzene Reduction Unit (BRU) Project Update. This project involved a modification of the H-1001 Reformer Heater to achieve the design hydrogen production rate within the 1000 Unit Hydrogen Plant. Expansion of the 1000 Unit Hydrogen Plant was included in the MAQP #1821-18. However, the 1000 Unit Hydrogen Plant expansion changed the characteristics of the PSA tailgas (e.g., the heat content (British thermal units per standard cubic feet (Btu/scf) declined and the volume produced increased (standard cubic feet per minute (scfm)). According to CHS, the total heat input associated with the PSA tailgas remained nearly the same. As a result, the existing PSA tailgas burners on the H-1001 Reformer Heater could not handle the increased volume of PSA tailgas without excessive pressure drop and the 1000 Unit Hydrogen Plant production rate became limited by the volume of PSA tailgas that could be combusted. The permit modification replaced the PSA tailgas burner tips with tips that have larger ports such that all of the PSA tailgas generated could be combusted in H-1001. CHS proposed replacement of the supplemental fuel (e.g., natural gas, refinery fuel gas) burners in H-1001 to achieve improved NOx emission performance. The previous heater was physically capable of combusting refinery fuel gas but could not meet the existing oxides of nitrogen (NOx) permit limits while doing so. Additionally, the modified heater will have a higher maximum design firing rate (191.8 MMBtu-HHV/hr post project versus 177.7 MMBtu-HHV/hr) and a slight increase in the actual firing rate.

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

In addition to those items mentioned above, this permit action included miscellaneous updates and amendments. CHS requested to discontinue use of the sulfur dioxide (SO_2) Continuous Emissions Monitoring System (CEMs) on the H-1001 stack because H-1001 was subject to 40 Code of Federal Regulations (CFR) 60, Subpart Ja which included exemptions from hydrogen sulfide/sulfur dioxide (H_2S/SO_2) monitoring requirements for fuel gas streams that are inherently low in sulfur content. The primary fuel to H-1001, PSA tailgas is inherently low in sulfur content. CHS already monitors the H_2S content of the refinery fuel gas (RFG) to be combusted in H-1001 as supplemental fuel, which would meet the monitoring requirements of Subpart Ja.

CHS requested that the Department remove condition IV.E.4 which requires the use of statistically significant F-factor values in determining compliance with NOx and carbon monoxide (CO) limits for the H-102 Reformer Heater. Rather, CHS proposed that results of the required performance testing be used to calculate an appropriate emission factor to demonstrate ongoing compliance with NOx and CO limits.

MAQP #1821-27 replaced MAQP #1821-28.

On November 14, 2012, CHS Inc. submitted a request to the Department to amend several items in their permit. The following provides a summary of the items that changed in MAQP #1821-27 as a result of this action:

- In Section IV.A.3, CHS requested to remove 40 CFR 60, Subpart Ja from this section of the permit as the units subject to this New Source Performance Standard (NSPS) are already identified in Section X.

- In Section VI.C.1 and XVI.C.6, CHS requested that the Department remove existing gasoline and distillate loading rack and associated VCU from the VOC limit in these sections. In addition, the Department removed the notification requirement on the existing truck loading rack and associated VCU.

- Section VI.G.1.d, required notification once the existing propane loading rack has been rendered inoperable. As clarification, CHS does intend to permanently shut down the existing propane loading rack but not the existing propane storage facilities as was previously stated in error in the CHS permit application. The Department removed the notification requirement on the existing propane loading rack. The Department understands that the propane storage facilities were not included in this action. Because the propane storage is not listed in the permit, this will not require an administrative change other than to note the clarification.

- In MAQP #1821-27, CHS proposed replacement of the burners in the H-1001 Reformer Heater. The firing rate and associated limits only apply once the heater has restarted after the retrofit. CHS requested that the Department clarify that the limits included in MAQP #1821-26 would apply until such time that the H-1001 Reformer Heater has gone through its shakedown period (CHS requested 180 days after initial startup). The Department clarified this by adding the limitations previously listed in MAQP #1821-26 back into the permit.

- The Department previously noted that there was an error in the CO limit for the H-1001 Reformer heater. As such, CHS requested that the limit in VIII.D.3.e be corrected as follows: 0.02 lb/MMBtu-HHV, or 16.8 tons per rolling 12-calendar month total.

- In Section X.D.2, CHS requested that the last sentence of the introductory paragraph be deleted as it incorrectly indicates that the conditions apply once the new FCC-Charge-Heater begins operation.

- CHS requested that Section X.D.2.a.a. be changed for consistency with the other emission limits in that that section as follows: The FCC-Heater-NEW shall be equipped with ULNB and the firing rate of the heater shall not exceed 66 MMBtu/hr-HHV based on a rolling 30-day average.

- CHS requested that Section X.G.2 and Section X.H be modified to reflect the fact that there isn't a CO CEMs on the new FCC-Heater-NEW.

MAQP #1821-28 replaced MAQP #1821-27.

On January 22, 2013, CHS Inc. submitted an application for a modification to MAQP #1821-28. As a result of the Mild Hydrocracker Project, the quantity of gasoil converted to diesel will generally increase and the quantity converted to gasoline will generally decrease. This will result in a lower rate of gasoline production at the FCCU and the downstream Alkylation Unit. According to CHS, these refinery gasoline component streams have relatively high octane ratings and are typically blended with gasoline component steams that have lower octane ratings to meet product octane specifications. CHS has determined that there may be times following the Mild Hydrocracker Project's startup that the refinery will not be able to produce enough of the higher octane gasoline components necessary to meet the minimum octane product specifications. As a result, CHS proposed to complete the Gasoline Component Unloading Project as included within the January 22, 2013, application. CHS also indicated that the impact from the MHC Project is not the only justification for completing the Gasoline Component Unloading Project. CHS anticipates that there may be other market-driven factors that will require CHS to increase or decrease the octane rating of its gasoline product in the future.

The January 22, 2013, application contained information necessary to incorporate permit changes associated with CHS's proposal to install the facilities necessary to unload various gasoline components from railcars to existing storage tanks such that these components can be blended into refinery products. The Gasoline Component Unloading project is considered an aggregate part of the previously approved Mild Hydrocracker Project and therefore, was evaluated as such for purposes of determining its regulatory applicability with respect to PSD applicability.

In addition to the proposed Gasoline Component Unloading project, CHS also requested the following changes to BACT permit conditions and monitoring requirements associated with the H-1001 Reformer Heater, FCC Charge Heater, and Gasoline and Distillate Truck Loading Rack VCU.

- For H-1001 and the FCC Charge Heater, CHS requested that permit conditions expressed in terms of MMBtu be removed from the permit and that permit limits in terms of mass (i.e., lb/hr and tons per rolling 12-calendar month total) be maintained.

  CHS offered the following explanation for removal of these permit conditions:

  > *The H-1001 Reformer Heater utilizes two fuel sources. The PSA tailgas fuel stream is generated within the 1000 Unit Hydrogen Plant and supplies the majority of the fuel required by the heater during normal operation. The supplemental fuel source is either refinery fuel gas (RFG) or natural gas. The RFG has a relatively consistent BTU content and is monitored through existing systems including an online process GC (i.e. not a CEM) and lab analysis of grab samples such that the composition and subsequently the BTU content of the RFG is characterized on a regular basis. In contrast, the PSA tailgas fuel stream has a BTU content that can vary significantly over the course of a day or week. Additionally, it does not have an online GC or a reliable grab sampling system such that its BTU content can be characterized in a frequent or accurate enough manner to be useful in assuring compliance with limits based on short term measurements of the fuel BTU content. CHS estimates that due to the sampling issues only 20% of the samples collected of the 1000 Unit PSA tailgas are valid samples. In consideration of this issue, CHS proposed in the comments to the Preliminary Determination for MAQP #1821-27 that a stack flue gas flow rate monitor be installed for use along with the existing NOx and CO CEM to demonstrate compliance with mass emission limits in place of the proposed limits expressed in terms of MMBtu. CHS believes this approach is appropriate for the following reasons:*

- *The proposed mass emission limits were derived by simply multiplying the MMBtu-based limits together;*

- *The mass limits better accomplish the goal of restricting the short- and long-term emissions from the H-1001 Reformer Heater through the use of continuous concentration and flow monitors rather than determining an average of a number of grab samples; and*

- *The mass limits are expressed in terms the CHS Operations staff has the ability to monitor in order to ensure continuous and ongoing compliance.*

As requested, the Department removed the permit conditions expressed in terms of MMBtu for the H-1001 Reformer Heater and the FCC Charge Heater.

- As included within the application for MAQP #1821-27, CHS proposed to install a new gasoline and distillate truck loading facility, which included an associated VCU as the control device for vapors displaced from the truck during the loading process. CHS identified BACT for the loading rack as a VCU that controls VOC emissions to a maximum of 10 mg/l of gasoline product loaded. The new loading rack is subject to 40 CFR 63 Subpart CC (NESHAP for Petroleum Refineries) requirements, which requires the loading rack to the meet the requirements of 40 CFR 63 Subpart R. CHS requested that the BACT permit monitoring requirement be updated to more closely reflect the Subpart R requirement. The Department modified the condition as requested.

MAQP #1821-29 replaced MAQP #1821-28.

On April 15, 2013, CHS Inc. submitted an application for a modification to MAQP #1821-29. The application was submitted concurrently with CHS's request for renewal of Operating Permit OP1821-10 and included the following:

- 40 CFR 60, Subpart J applicability updates: Conditions indicating NSPS Subpart J applicability to all CHS Refinery's fuel gas combustion devices were updated to reflect NSPS Subpart Ja requirements, where necessary.

- Clarification of 40 CFR 60, Subpart Ja applicability: Specific to Boiler #12, CHS requested that the MAQP be clarified to reflect that Boiler #12 meets the NSPS Subpart Ja definition of a "fuel gas combustion device" requiring compliance with the SO_2 emission limit or the H_2S in fuel gas limit.

- Railcar Light Product Loading Rack NESHAP applicability: Based on the facility's SIC code, 40 CFR 63, Subpart CC applies to the light product loading racks and 40 CFR 63, Subpart R does not apply. CHS requested clarification of this applicability within the MAQP.

- 40 CFR 60, Subpart GGGa applicability updates: The MAQP identified applicability of NSPS Subpart GGGa to refinery fuel gas supply lines to Boiler #12. However, because Boiler #12 commenced construction after November 7, 2006, it is subject to NSPS Subpart GGGa.

- 40 CFR 60, Subpart VV/VVa applicability updates: NSPS Subpart VV or VVa apply to affected facilities in the Synthetic Organic Chemical Manufacturing Industry (SOCMI). The CHS refinery is not classified as a SOCMI industry. The LDAR rules that apply to the CHS refinery include NSPS Subparts GGG and GGGa and MACT Subpart CC. Each of these rules reference specific conditions in NSPS Subpart VV and VVa, CHS proposed reference only GGG or GGGa.

- Consent Decree reference updates: Several conditions in the MAQP still contained references to the consent decree where obligations have been met. CHS requested to have these references removed.

- References to Billings/Laurel SO_2 Emissions Control Plan, as approved into the SIP: CHS requested corrections be made to the MAQP where the SO_2 SIP was referenced incorrectly.

- "Plant-wide" emissions limits: Since issuance of MAQP #1821-05, inadvertently, changes have been made to the original list of emitting units to be included in these emission caps for each pollutant. Additionally, as a result of the addition and removal of various emitting units since the creation of these emission caps, the term "plant-wide" is no longer appropriate. CHS requested the list be corrected and the term "plant-wide" removed from the permit.

- Administrative Amendments: CHS requested various administrative changes be incorporated into the MAQP.

MAQP #1821-30 replaced #MAQP 1821-29.

On August 13, 2013, the Department received from CHS an application for modification of the MAQP and the associated Title V permit to modify limits for the H-901 and H-902 process heaters.

The H-901 heater is fired on refinery fuel gas, and its function is to heat the feed into the hydrogenation reactor, which serves to remove sulfur from the process stream. The sulfur reducing process occurs through what is called the Ultra Low Sulfur Diesel (ULSD) reactors. Heat is required by the H-901 process heater to assure the Ultra Low Sulfur Diesel reaction occurs with the appropriate sulfur removal efficiency required to make low sulfur fuels specifications.

The H-902 heater is also fired on refinery fuel gas, and this heater heats the sulfur-reduced process stream for fractionation and stripping back into naphtha, #1, and #2 diesel. An increased amount of heat from the H-902 heater provides for increased recovery of #1 diesel by allowing for increased stripping rates.

Due to changes in the quality of crude oil and the ULSD feed, which affects the sulfur removal process, increased market demand for #1 diesel, proposed to increase emissions limits on the H-901 and H-902 heaters. The H-901 and H-902 mass rate-based emission limits were originally determined in MAQP #1821-09. These limits were based on the heat input rate of the heaters, and the emissions rate guarantee of the ultra-low oxides of nitrogen (NO_X) burner design selected as BACT. The design of the burners was based on a NO_X pound per million British Thermal Units (lb/MMBtu) guarantee. In the MAQP #1821-09 application, the maximum rated heat input capacity of the heaters were presented based on the maximum expected process heat input requirements of the heaters at that time. Limitations in the form of tons per rolling twelve (12) month period and pound per hour were accepted by CHS based on the expected needs of the burners.

CHS proposed to increase the heat input component of the emission limit calculation, maintaining the Ultra-Low NO_X Burner performance on a lb/MMBtu basis, and allowing for a higher firing rate in each heater. The proposed increased NO_x, carbon monoxide (CO), and volatile organic compounds (VOC) emission limits are based on an increase in maximum heat rate input from 27.46 million British thermal units per hour (MMBtu/hr) to 32.60 MMBtu/hr on the H-901 heater, and from 55.26 to 65.10 MMBtu/hr on the H-902 heater, on a higher heating value basis. CHS has not requested to increase allowable oxides of sulfur limits.

CHS also proposed to monitor emissions rates from the H-901 and H-902 heaters through use of Continuous Emissions Monitoring Systems (CEMS). This method supports increased compliance monitoring abilities for CHS, allowing for quicker compliance status determinations. At the request of CHS, the Department has incorporated this compliance demonstration method.

Because this action relaxes previously assigned permit limits at a major source, CHS presented a Prevention of Significant Deterioration (PSD) look-back to fulfill the requirements of ARM 17.8.827. This rule requires that if a permit limit is relaxed, it must be demonstrated that PSD was not circumvented during previous permit actions that relied on the more stringent permit limit. Because the heaters' capacities are larger than originally presented in 2003, CHS provided demonstration that if the associated increased capacity had been recognized in the 2003 application, and also in association with other associated projects applied for after 2003, it would not have made the ULSD project or the other associated projects subject to PSD. This analysis is included within the application on file with the Department.

MAQP #1821-31 replaced MAQP# 1821-30

On October 21, 2013, CHS Inc. submitted concurrent applications for a modification to MAQP #1821-30 and OP1821-12. At the time of receival, permit actions were also under way for updates under OP1821-13, OP1821-14 and for MAQP#1821-31.

Under the proposed action, CHS added a new 100,000-barrel (approximately 4,040,000 gallon) intermediate storage tank. The tank was identified as Tank 146 and was a vertical fixed roof tank capable of storing sour gas oil, sweet gas oil, light coker gas oil, or raw diesel. Due to the physical properties of sweet and sour gas oil, a steam coil was also installed in Tank 146 to reduce the viscosity to a point low enough for pumping purposes. Additionally, when in sour gas oil service, raw diesel service or light coker gas oil service the tank would be blanketed with natural gas to prevent oxygen from entering the tank. The tank is for storage of the four identified intermediate products only and not allowed as a "final product" storage tank or for storage of other products not consistent with the four intermediate products identified in the application.

Additional Permit Actions. A De minimis request was also received by the Department on July 29, 2013, for piping modifications at the Railcar Light Product Loading Rack. Under the request, piping modifications were approved to allow converting loading spots that currently only allow gasoline loading to also allow diesel loading and for spots that currently only allow diesel loading to also allow gasoline loading. The MAQP did not have any language describing the piping detail of the loading spots. Since physical piping modifications were allowed under this de minimis request, this reference has been added for completeness. A De minimis request was also received by the Department on December 5, 2013, and approved on December 9, 2013. Since the de minimis request was issued prior to the end of the public comment period, this de minimis reference has been added for completeness. Under the de minimis request, the potential input of the #2 Crude Unit Vacuum Heater was lowered from 86 MMBtu-HHV/hr down to 62 MMBtu-HHV/hr.

MAQP #1821-32 replaced MAQP #1821-31.

On July 31, 2014, the Department received from CHS an application for replacement of the main refinery flare. The flare was reaching the end of its mechanical life and was in need of replacement. The replacement flare is subject to New Source Performance Standards (NSPS) Subpart Ja (40 CFR 60 Subpart Ja), as well as 40 CFR 60.18 (Control Device and Work Practice Standards) and 40 CFR

63.11 (Control Device and Work Practice Requirements). Proposed as part of the main flare replacement project, was installation of a flare gas treatment and recovery system. Vent gases captured in the recovery system will be directed to amine treatment for removal of reduced sulfur compounds and returned to the refinery fuel gas system to be burned in fuel gas combustion units (displacing natural gas usage). During times when the amount of captured vent gases exceeds the flare gas recovery system capacity, the gases would pass through the liquid seal of the flare for destruction of the gas by combustion in the flare. Combustion of these gases is necessary to destroy the various components which would otherwise have potential to be emitted in amounts which would pose serious threat to human health and the environment.

CHS submitted as part of the flare replacement application a proposal to replace the current Zone D Sour Water Stripper with a new Two Stage Sour Water Stripper. The Zone D Sour Water Stripper was undersized for the amount of nitrogen content being seen in some crude oil supplies to CHS. Because flare gas recovery will result in additional sour water which must be treated, the needed upsizing of the Zone D Sour Water Stripper could also be determined related to the current flare project from a New Source Review (NSR) perspective, as sizing of the Sour Water Stripper would need to include the additional needs created by the flare gas recovery system. The new Sour Water Stripper allows the refinery to increase wash rates. The process generates two vent streams; one rich in reduced sulfur compounds that will be processed at the Sulfur Recovery Units, and one rich in ammonia, which will have some reduced sulfur and hydrocarbon as well. The ammonia stream will be sent to a caustic-based scrubber and ammonia combustor. The combustor is subject to Montana Code Annotated 75-2-215 incinerator review, as well as Best Achievable Control Technology review. Selective Catalytic Reduction control technology was required to control Oxides of Nitrogen from the combustion process, and waste heat in the ammonia combustor exhaust used to generate steam.

On August 27, 2014, the Department received supplemental information from CHS regarding additional scope of the flare gas recovery project. CHS proposed that the Zone E Flare (known as the Coker Flare), be equipped with a seal and necessary piping to provide for recovery of the Zone E flare gases. Zone E flare gas could go to the same refinery fuel gas treatment and recovery system, or through the Zone E Amine unit and to Zone E refinery fuel gas consumers.

In addition, administrative updates were made to remove language pertaining to timing of applicability of certain conditions or initial testing and notification requirements which are no longer applicable. Changes recognized in these updates include completion of conversion of the hydrodesulfurization unit to the mild hydrocracker, replacement of the C-201B compressor with an electrically driven compressor, update of the #1 Crude Unit's NSPS applicability, completion of the H-1001 burner retrofit, and installation of the new FCC charge heater. **MAQP #1821-33** replaced MAQP #1821-32.

On November 7, 2014, the Department received from CHS an application for three separate projects, as discussed below:

Crude Blending Project:

Over time, the quality of the crude oil supply to CHS has declined and become more variable. CHS proposed to install two new crude oil storage tanks each with a capacity of approximately 200,000 barrels. The tanks, used in conjunction with existing crude oil storage tanks, would provide improved segregation of crude oils with different characteristics such that an optimum crude oil blend can be supplied to the #1 and #2 Crude Units. As a result of optimizing the crude feed quality, the feed rate to each of the Crude Units may be able to increase by as much as 3,000 barrels per day, therefore, the increased utilization of the crude units, as well as the Ultra-Low Sulfur Diesel, Naphtha Hydrotreater, and Platformer Units, are accounted for in the project review. With exception of the new tanks and related piping, no physical modifications to existing equipment were proposed.

Tank 147 Project:

CHS installed a new 100,000-barrel capacity fixed roof tank (Tank 147) to be used for the storage of intermediate products. Installation of this tank allows CHS to better manage inventories during maintenance outages and to reduce the frequency of service changes for tanks that have multiple service capabilities.

This tank is insulated and heated to keep the intermediate at a workable viscosity, and designed with a natural gas blanketing system to avoid oxygen from contacting the stored intermediate products, to avoid downstream fouling. This project resulted in more tanks in dedicated service, but not in the ability to process additional crude oil or produce additional product on an annual basis.

Coke Trucking Project:

CHS added truck shipping of Petroleum Coke to the refinery. At times, due to railcar availability issues, the refinery must reduce production rates due to the limited petroleum coke storage. This project utilized the existing railcar loading system to load trucks when needed. This project did not require modification of any existing emission unit; however, the addition of fugitive road dust emissions is expected.

Administrative Changes:

CHS submitted to the Department the specification sheets for the flare gas recovery system compressors. The specification sheets demonstrate to the Department's satisfaction the size requirements identified in MAQP #1821-33. CHS suggested, and the Department agrees, that demonstration of compliance with the design of the flare gas recovery system compressors is most straightforward by requiring the make and model noted on the specification sheets to be installed. The condition regarding size of the compressors was replaced with language requiring that the specific make and model compressors be installed.

CHS also requested that the 'new' flare be referred to utilizing different terminology, for clarification purposes from an NSPS perspective. The Department updated the permit language as requested.

CHS requested that the requirement to monitor O_2 on the H-901 and H-902 heaters be removed. NO_X CEMS is required, including a flowrate monitor; however, the need for O_2 monitoring is not necessary because the relevant emissions limit for this condition is on a lb/hr basis. The Department removed the requirement for the NO_X CEMS as required by this condition to include an O_2 monitor.

MAQP #1821-34 replaced MAQP #1821-33

On September 16, 2015, the Department received an application from CHS for a large expansion to the existing refinery. Throughout the permit, the project is referred to as the Grassroots Hydrocracker Project (GRHC). The permit action included information submitted to process the MAQP application for both New Source Review and Prevention of Significant Deterioration (PSD) requirements. The primary objective of the GRHC project was to increase the diesel production capacity at the refinery.

The GRHC expanded diesel production with the addition of a new Hydrocracker (HC) Unit and supporting Hydrogen Plant (HRU). To accommodate the new HC, modifications were made within the existing #1 Crude Unit (#1 CRU), Mild Hydrocracker (MHC) and Fluidized Catalytic Cracking Unit (FCCU). To allow for increased product shipment by rail, the capability of the existing light product railcar loading rack was expanded. The GRHC also includes the installation of two new tanks and an increase in the amine treatment capacity at the refinery.

The new HC was designed to process approximately 25,000 barrels per day of feed. The unit includes three fired heaters including two identical Reactor Feed Heaters each with a design heat input capacity of 75 MMBtu/hr (HHV) and a Fractionator Feed Heater with a design heat input of 126.3 MMBtu/hr (HHV).

The new HRU includes a fired heater with a design heat input capacity of 562 MMBtu/hr (HHV). The reformer type hydrogen unit is designed to provide up to 40 MMSCFD of hydrogen. In addition to supporting the increased hydrogen demand associated with the project, the new HRU also increases the reliability of the hydrogen supply at the refinery.

Although not related to the GRHC project, the application also included a request to modify the short-term NO_x permit limit for H-102. This change provides for a 0.43 lb/hr increase in NO_x and accounts for higher concentrations of H_2 in the fuel gas. This proposed change was also included in the modeling analysis for the GRHC and included in the BACT analysis where H-102 and other conventional heaters were all proposed for a 0.035 lb/MMBtu BACT limit.

Note: An application assigned **MAQP #1821-35** was submitted but later withdrawn and therefore, MAQP #1821-35 does not exist. **MAQP #1821-36** replaced MAQP #1821-34. This project is still under construction.

On August 1, 2016, the Department received from CHS an application for modification of the Montana Air Quality Permit. CHS proposed to increase the size of the crude blending tanks originally permitted in MAQP #1821-34. Because, over time, the quality of the primary crude oil supply to the Laurel Refinery had declined and become more variable, the utilization of process units downstream of the crude units also declined. The crude blending project was originally permitted in MAQP #1821-34. This proposed permit modification was intended to provide improved segregation of crude oils with different characteristics with the goal of enabling blending of the crude oil to allow more utilization of the existing refining process. No physical change was proposed to any other refining equipment. As a result of increased utilization of existing capacity, an increase in actual emissions was expected from the operational change. The project did not trigger the Prevention of Significant Deterioration (PSD) program because increases in actual emissions were less than PSD program thresholds. The tanks were subject to Best Available Control Technology (BACT) review through Montana's minor source permitting program. This action permitted the increase in crude oil tank sizes and reviewed the action as if the tanks were new emission sources.

In addition, CHS proposed various administrative changes to the permit to remove notification and reporting requirements associated with previous projects which have been completed. The requirements that were fulfilled and are no longer necessary were updated accordingly. **MAQP #1821-37** replaced MAQP #1821-36.

On May 11, 2017, the Department received from CHS an application for modification of MAQP #1821-37. CHS proposed two separate unrelated projects within the same application. The first project would have added a thermal combustor (incinerator) to control emissions from the water oil separators, dissolved flotation units, and a new wastewater surge tank. On May 25, 2017, CHS submitted a letter withdrawing this portion of the project while confirming the modification for the second project. The second project would have increased the amount of petroleum coke shipped off-site using trucks. The MAQP limited the number of trucks to 1000 trucks per year on a rolling 12-month basis. This equated to 43,500 tons based on each truck carrying 43.5 tons of petroleum coke. CHS requested to increase the allowable truck shipments to a total of 175,200 tons of coke per year determined monthly on a rolling 12-month total. This was calculated based on 5,840 trucks on a rolling 12-month basis assuming 30 tons per truckload. No physical change was proposed to any other refining equipment. As a result of increased utilization of existing capacity, an increase in actual emissions was expected from the shipping change from rail to trucks. The project did not trigger the PSD program because increases in actual emissions were less than PSD program thresholds.

In addition, CHS proposed various administrative changes to the permit to remove notification and reporting requirements associated with previous projects which were completed. An additional request by CHS was received on June 13, 2017, to include some administrative changes. Those administrative requests were incorporated to avoid an additional permit action. The requirements that were fulfilled and no longer necessary were updated and conditions for equipment no longer in service were removed. **MAQP #1821-38** replaced MAQP #1821-37.

On July 27, 2017, the Department received an application from CHS for modification of their Montana Air Quality Permit. The requested change provided for a new type of catalyst to be installed into the Ultra Low Sulfur Diesel (ULSD) reactor. The new catalyst resulted in additional hydrogen usage due to its improved reaction rates. The additional hydrogen required would come from the new hydrogen plant which was part of MAQP #1821-36 issued on December 16, 2015, and part of the Grass Roots Hydrocracker Project (GRHC). Since the catalyst change was not possible without the additional hydrogen produced from the GRHC Project, this project was technically dependent upon the original GRHC Project. Therefore, this application updated the GRHC project to include the catalyst change-out, updated the netting analysis, and all elements required for a complete PSD application. All elements associated with PSD permit applications were followed, including public notice to Federal Land Managers. The Best Available Control Technology (BACT) analysis submitted in this revised PSD action also re-established a new construction timeframe for the GRHC Project.

The original GRHC application, received on September 16, 2015, increased the diesel production capacity at the refinery. The description of projects details from MAQP #1821-36 is included here.

The GRHC expanded diesel production with the addition of a new Hydrocracker (HC) Unit and supporting Hydrogen Plant (HRU). To accommodate the new HC, modifications were made within the existing #1 Crude Unit (#1 CRU), Mild Hydrocracker (MHC) and Fluidized Catalytic Cracking Unit (FCCU). To allow for increased product shipment by rail, the capability of the existing light product railcar loading rack was expanded. The GRHC also included the installation of two new tanks and an increase in the amine treatment capacity at the refinery.

The new HC was designed to process approximately 25,000 barrels per day of feed. The unit included three fired heaters including two identical Reactor Feed Heaters each with a design heat input capacity of 75 MMBtu/hr (HHV) and a Fractionator Feed Heater with a design heat input of 126.3 MMBtu/hr (HHV).

The new HRU included a fired heater with a design heat input capacity of 562 MMBtu/hr (HHV). The reformer type hydrogen unit was designed to provide up to 40 MMSCFD of hydrogen. In addition to supporting the increased hydrogen demand associated with the project, the new HRU also increase the reliability of the hydrogen supply at the refinery.

Although not related to the GRHC project, there was also a change made to the H-102 NO_x permit limit. This proposed change was also included in the modeling analysis for the GRHC and included in the BACT analysis where H-102 and other conventional heaters were all proposed for a 0.035 lb/MMBtu BACT limit. **MAQP #1821-39** replaced MAQP #1821-38.

On May 17, 2018, the Department received an application from CHS for modification of their Montana Air Quality Permit. The requested change proposed to increase the SO_2 ton per rolling 12-month total limit and update the SO_2 BACT limits for the Zone D Sulfur Recovery Plant (SRP). The requested changes were largely the result of unforeseen impacts from the installation of the Flare Gas Recovery System in 2015 which provided for large facility-wide reductions in SO_2 but increased the process variability in the feed gas stream exiting to the Zone D SRP tail gas treatment unit (TGTU) and upon combustion in the tail gas incinerator (TGI) resulted in higher SO_2 emissions. This process variability resulted in higher sulfur content in the Zone D SRP and upon combustion in the tailgas treatment incinerator (TGTU) results in higher SO_2 emissions. This increase in sulfur content eliminated the operational compliance margin with the current Zone D SO_2 annual limit. Further, the requested changes addressed short-term operation during normal operation of the SRP and aligned the short-term BACT limit with short-term averaging periods and concentration consistent with the NSPS for sulfur plants, and for startups and shut-downs proposed in the new MACT standard 40 CFR 63 Subpart UUU- Refinery MACT. As these proposed changes span several projects at the refinery; the new limits were reviewed relative to previous Non-attainment Area New Source Review decisions to ensure the earlier permit determinations would not have resulted in any of those projects becoming a major modification. As part of the permit action, the daily maximum limit of 341.04 lbs SO_2 was eliminated as it is redundant with the current and maintained hourly limit of 14.21 lbs SO_2.

MAQP #1821-40 replaced MAQP #1821-39.

On September 7, 2018, the Department received an application from CHS for modification of their Montana Air Quality Permit. The requested change proposed to add a thermal combustor as a control option for the API separator and Dissolved Air and Nitrogen Flotation (DAF/DNF) vents. These will now be referred to collectively as Dissolved Gas Flotation (DGF) units. These vents were controlled by carbon adsorption and this request allowed for either the new thermal combustor or carbon to be used to control the emissions. The purpose of the request was to address the high cost of carbon replacement and provided an additional control option. CHS provided an analysis of the proposed project, and associated emissions increases and demonstrated the project was below PSD thresholds. The thermal combustor was expected to have a higher control efficiency versus carbon, but each control option is approved for control. As the thermal combustor met the definition of an incinerator under MCA 75-2-103(11) MCA, CHS also provided a demonstration that the thermal combustor passed the required human health risk assessment. The request also included a number of administrative changes not specifically related to the thermal combustor.

MAQP #1821-41 replaced MAQP #1821-40.

On February 21, 2019, the Department received an application from CHS for modification of MAQP #1821-41. The requested change proposed to modify the MAQP to reflect the final scope of the Grassroots Hydrocracker Project (GRHC) and modified two limits which were established as part of the GRHC. Portions of the project which were permitted as part of the GRHC were no longer being constructed including the New Hydrocracker and therefore, conditions associated with the New Hydrocracker were removed. The Hydrogen Reformer Heater permitted as part of the GRHC was given a CO limit to specifically cover periods of startup. The current startup for the Hydrogen Reformer Heater took longer to startup and reach stable operation than the form of the current CO limit. The current limit of 41.6 lb/hr (hourly rolling 24-hr average) was not able to be achieved based on the allowable heat ramp of 50°- 90° F per hour. Recent data during startup indicated it took approximately 36 hours and therefore, requested that the form of the limit be modified to be based on an hourly rolling 36-hour average. No change in the numeric limit was requested. Related to the new Hydrocracker which was not being built, a Greenhouse Gas emissions multi-source total limit was included in the GRHC project. The CO_2e limit included the Hydrogen Reformer Heater, HC Reactors Heaters (H-801 and H-802), HC Fractionation Heater and the FCCU. The two remaining sources were the Hydrogen Reformer Heater and the modified FCCU. The scaled back GRHC project remained subject to PSD and the revised project emissions increase was greater than 75,000 tons per year CO_2e, therefore CO_2e limits were still required for the two remaining sources. In addition, the basis of the CO_2e limit for the Hydrogen Reformer Heater was updated based on the procedure in 40 CFR part 98 subpart P for Hydrogen Production. This uses the 2018 actual fuel and feedstock consumption scaled to the unit's 40 MMSCFD hydrogen production and the actual carbon content and molecular weight of the refinery natural gas supply. Since the Hydrogen Reformer Heater used refinery fuel gas (RFG), potential emissions were also evaluated using the actual carbon content and molecular weight of RFG. This second alternative provided the highest potential emissions of CO_2e. Several minor administrative clarifications were also incorporated into the MAQP including conditions where initial source testing had been completed.

MAQP #1821-42 replaced MAQP #1821-41.

On March 9, 2020, the Department received an application from CHS for modification of MAQP #1821-42. The requested change proposed to modify the MAQP to provide a refinery expansion which identified as the Multi-Unit Expansion Project, (MUE). The MUE included projects within the #2 Crude Unit (#2 CU), Mild Hydrocracker (MHC), Delayed Coker (DCU), and Naphtha Hydrotreater (NHT). The #2 CU will be modified to increase its capacity and to provide additional crude processing flexibility. The atmospheric distillation column within the #2 CU will be replaced, an existing process heater will be replaced, and the stack of another existing heater will be relocated. Additional modifications related to hydraulic capacity and heat balance will be completed. The MHC will be modified to increase its capacity. The three MHC reactors, H_2S stripper and high-pressure absorber will be replaced with higher capacity equipment and a naphtha stabilizer will be added to the unit. Additional modifications related to hydraulic and heat balance will be completed. The DCU will be modified to increase its capacity. A second Coker Charge Heater (H-7502) will be installed. Additional modifications related to hydraulic capacity and heat balance will be completed. Modifications to the NHT and associated support facilities will be made to improve management of unit feed and handling of heavier hydrocarbon gases (i.e., propane, butane, etc.). The project also involved replacing existing natural gas fired Boiler 9 with a higher capacity boiler (Boiler 13). Boiler 13 will be fired with refinery fuel gas (RFG).

Unrelated MAQP updates include a review of the current NOx limits on existing Boilers #11 and #12. This request is unrelated to the MUE project but revisits the original NOx limits which were established in 2006 for Boiler #11 and in 2008 for Boiler #12.

Several minor administrative clarifications were also incorporated into the MAQP including clarification on reporting requirements and making sure MAQP conditions reflect planned language to be included in the CHS Title V Renewal which is currently being updated. Administrative changes include moving to electronic submittal of reports to eliminate duplicate hardcopy submittals. The planned schedule represented a multi-year effort and must be completed in various phases which are planned to be coordinated with regularly scheduled maintenance turnaround starting in August 2020, and currently planned to be completed in 2024.

MAQP #1821-43 replaced MAQP #1821-42

On November 5, 2021, the Department received an application from CHS for modification of MAQP #1821-43. Additional information was requested by the Department on November 29, 2021. CHS responded on December 22, 2021, at which time the application was determined to be complete. With the December 22 response, CHS requested to maintain the proposed changes under Section 4 of the original application but to withdraw the changes proposed in Section 2 and Section 3 from the current application. Section 4 provided for more consistent reporting across the numerous refinery process units and minor clean-up of existing permit conditions. There were no physical modifications occurring with the revised scope of the application.

MAQP #1821-44 replaced MAQP #1821-43.

On July 15, 2022, the Department received an application from CHS for modification of MAQP #1821-44. With this permit application, CHS is proposing to modify the averaging time for the short term (lb/hr) NOx emissions limits on the H-901 and H-902 process heaters in the ULSD. The current limits are applicable on a rolling 24-hour average basis and CHS is proposing that the limits be revised to be applicable on a rolling 365-day average basis. The change is being proposed to reflect that the BACT emission rate of 0.02 lb NOx/MMBtu (HHV) is achievable on an annual average basis. CHS is not proposing an increase to the allowable annual emissions from the heaters. There are no physical modifications occurring with the scope of the application.

MAQP #1821-45 replaced MAQP #1821-44.

De Minimis Requests
Since just before and after the application for MAQP #1821-45 was received on July 15, 2022, a number of De Minimis actions have been received and processed by DEQ. DEQ concurred with each of the actions which are briefly highlighted below:

On June 17, 2022, DEQ received a de minimis notification. This notification requested concurrence to allow the use of a temporary combustor during the Spring 2023 maintenance turnaround at the refinery to safely control unexpected releases and protect the refinery upstream of the tie-point on the existing main flare header.

On September 6, 2022, DEQ received a de minimis notification. This notification requested needed changes to be able to process recovered oil in the refinery's delayed coker unit (coker). The project involves staging an atmospheric tank in the coker unit to receive batches of recovered oil to be processed as feed to the coker. In addition to the tank, a pump and piping system will be installed.

On November 7, 2022, DEQ received a de minimis notification. This notification requested concurrence for a new slotted floating roof on Tank 78.

On February 10, 2023, DEQ received a de minimis notification. This notification requested concurrence that operating the air preheater for the Fluidized Catalytic Cracking Unit (FCCU) on a continuous basis is a de minimis change.

On June 28, 2023, DEQ received a de minimis notification. This notification requested concurrence that truck loading of sulfur from Zone A on a permanent basis and temporarily from Zones D and E can be done under a de minimis approval.

On August 11, 2023, DEQ received a de minimis notification. This notification requested concurrence that a change in service for Tank 123 from #2 diesel to #1 diesel is a de minimis action.

On August 18, 2023, DEQ received a de minimis notification. This notification requested concurrence that a transition from the carbon adsorption system to a thermal vapor combustor for the API Separators and Dissolved Gas Flotation Units is allowed under MAQP #1821-45 and OP #1821-20.

On December 15, 2023, DEQ received a de minimis notification. This notification requested concurrence for the addition of two loading arms which will allow CHS to load two trucks and two pups at the same time.

On April 18, 2024, DEQ received a de minimis notification. This notification requested concurrence that a new coker feed tank is planned to replace a tank which has reached the end of its useful life.

On September 9, 2024, DEQ received a de minimis notification. This notification requested concurrence for a new slotted pole design as part of the upcoming Tank #74 roof replacement.

C. Current Permit Action

On September 11, 2024, DEQ received an application from CHS for modification of MAQP #1821-45. In the application, CHS is proposing revisions to the Multi-Unit Expansion Project (MUE), previously approved under MAQP #1821-43. The earlier permitting action authorized changes to the existing #2 Crude Unit, Mild Hydrocracker, Delayed Coker, and Naphtha Stabilizer. Revisions within the new application propose removal of a previously proposed process heater and steam boiler, as well as the addition of modifications to the Zone A and Zone D sulfur recovery plants (SRPs). Additionally, and unrelated to the MUE original project scope and the RMUE project scope, the new application proposes modifications for the Routine Molten Sulfur Trucking Project.

DEQ will refer to this application, proposing changes to the original MUE project, as the Revised Multi-Unit Expansion Project (RMUEP). With the scope changes, the RMUEP is no longer subject to PSD preconstruction requirements as emission increases no longer exceed applicable PSD thresholds. Previously, the MUE was subject to PSD for significant emission increases of NOx, PM_{10} and $PM_{2.5}$. The RMUEP revisions remove the addition of the new Coker Charge Heater (H-7502), remove the addition of the proposed new Boiler 13, and no longer proposes shuttering the existing Boiler 9. The Routine Molten Sulfur Trucking Project would add the ability for permanent molten sulfur truck loading from Sulfur Recovery Plants (SRPs) in Zone D and E, and evaluates the use of molten sulfur truck loading in Zone A as a change in the method of operation. The Routine Molten Sulfur

Trucking Project is not a major modification and not subject to PSD preconstruction requirements for any pollutant.

MAQP #1821-46 replaces MAQP #1821-45.

D. Process Description – Permitted Equipment

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

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

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

Hydrogen Plant – This unit produces pure hydrogen from propane/natural gas and recycled hydrocarbon from the hydrodesulfurizer, which, in turn, is used in the HDS unit. The feed is first purified of sulfur and halide compounds by conversion over a cobalt/molybdenum catalyst and subsequent absorption removal. The purified hydrocarbon is mixed with steam and the whole stream is reformed over a nickel catalyst to produce hydrogen (H_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 installed and a third reactor may be added in the future. The reactors contain one or more proprietary hydro-treating catalysts, which convert combined sulfur and nitrogen in the feed into hydrogen sulfide (H_2S) and ammonia (NH_3). Effluent off the reactor flows to a hot high-pressure separator where the vapor and liquid phases separate. The vapor/liquid stream then enters the cold high-pressure separator where the phases separate. Liquid water separates from the liquid hydrocarbon phase and collects in the boot of the vessel where vapor separates from the liquids. The vapor stream from the cold high-pressure separator flows to the high-pressure absorber, where it is contacted with amine solution to remove H_2S. The vapor stream is then subjected to a water wash to remove entrained amine. Amine, rich in H_2S, is pressured from the bottom of the absorber to the amine regeneration unit. The scrubbed and washed gas leaves the top of the high-pressure absorber and passes to the recycle cylinders of the make-up/recycle gas compressors. A portion of the discharge gas from these compressor cylinders is used as quench to control the inlet temperatures of the second reactor (and possibly a third reactor in the future).

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

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

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

A reactor charge heater (H-201) and fractionator feed heater (H-202) is utilized by the HDS unit. H-201 design heat input rate is 37.7 MMBtu/hr. Once the HDS reactors are at operating temperature, the process is exothermic. As a result, H-201 firing rates are reduced. For purposes of this application, the worst-case assumption is made that H-201 always operates at 80% for design (30.2 MMBtu/hr and 31.2 Mscf/hr). H-202 heat input design rate is 27.2 MMBtu/hr. Similar to H-201, once the HDS reactors are at operating temperature, the process is exothermic and produces sufficient heat to sustain the reaction temperature. Excess heat is recovered and transferred to the fractionator feed which reduces the need for the fractionator feed heater. For purposes of this application, the worst-case assumption is made that H-202 operates at 75% of full design capacity (20.4 MMBtu/hr and 21.3 Mscf/hr).

Amine Unit – A solution of amine (nitrogen-containing organic compounds) in water removes H_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 – As part of MAQP #1821-33, CHS proposed a new two stage Sour Water Stripper. The New Zone E SWS proposed has a capacity of approximately 360 gallons per minute.

The Sour Water Stripper removes ammonia, reduced sulfur compounds, and small amounts of hydrocarbons from the sour water prior to directing the water to wastewater treatment or reuse. The sour water is to be treated in two stages which creates two vent streams. One vent stream, rich in reduced sulfur compounds, is to be treated at the Sulfur Recovery Plant. The other vent stream, rich in ammonia, is to be sent to a caustic-based scrubber to remove remaining reduced sulfur compounds and then incinerated. The incinerator is to be equipped with Selective Catalytic Reduction technology to reduce the amount of NO_X emitted from combustion of the ammonia.

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

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

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

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

Zone A's TGTU for SRU #1 and #2 Trains – The SRUs convert H_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-INC-22, 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-INC-22, is nearly 100%.

The SRU-INC-22 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-INC-22. 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-INC-22 is 10.85 MMBtu/hr and the unit is fired on refinery fuel gas. Therefore, these two fuel-burning devices, together, will potentially use 18.55 Mscf/hr of natural and refinery fuel gas (15.02 total MMBtu/hr).

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

Some of the major equipment items in the delayed coker unit include: a new 160.9 MMBtu-high heating value (HHV)/hr Coker Charge Heater (H-7501), a new Coke Storage Area and Solids Handling Equipment to store and transfer the 800 short tons per day of coke product to rail cars for shipment; a new Coker Flare used exclusively to control emissions during start-up, shutdown, and malfunctions (no continuous vents will be flared); and a new coker amine unit and a Zone E (previously called Coker) SRU/TGTU/TGI, which is designed to process 70.6 long tons per day of sulfur. There will be emissions from a Coker Unit Oily Water Sewer and Cooling Tower.

Main Refinery Flare and Flare Gas Treatment and Recovery System – The Main Refinery Flare combusts flammable, toxic, and corrosive vapors to less objectionable compounds. Vent gases created as part of normal operations of a refinery, as well as emissions associated with startup, shutdown, and malfunction of refinery equipment, if vented uncontrolled, would provide for a significantly higher risk to human health and the environment than as occurs in being flared. The Main Refinery Flare provides an important pollution control and safety function during both emergency and routine operations. Emergency flaring may include flaring from pressure relief flows or emergency depressurization of process equipment. Venting of gases may be required for maintenance or as a part of startup or shutdown operations. Relatively continuous generation of vent gases are created from, for example, captured gas seal leakages from various equipment or as a necessary part of pressure control.

The Replacement Refinery Flare permitted as part of MAQP #1821-33 is expected to have an upset capacity of approximately 662,000 pounds per hour of flare gas for the maximum relief scenario, and a smokeless capacity of approximately 140,000 pounds per hour of vent gas. A Flare Gas Treatment and Recovery System is to be installed, where recovered vent gases will be treated via an amine treater to remove reduced sulfur compounds and send the gas to be burned in refinery fuel gas burning equipment instead of being flared. The Flare Gas Treatment and Recovery System will have a minimum capacity of 77,000 standard cubic feet per minute on an annualized basis. No change to the amount of gases created as a part of normal operations was permitted in MAQP #1821-33.

Under the Grassroots Hydrocracker Project (MAQP 1821-36) the following process changes are/were planned. The project description has been updated to reflect the final scope of the project (MAQP #1821-42).

New Hydrocracker (Hydrocracker #2) planned as part of MAQP #1821-36.

The GRHC includes scope originally included the construction of a second hydrocracker (HC) at the refinery. The addition of the new hydrocracker has since been canceled.

New Hydrogen Plant (Hydrogen Plant #3) after GRHC completed as part of MAQP #1821-36.

The GRHC included the construction of a new hydrogen plant (Hydrogen Plant #3) that converts natural gas, refinery fuel gas, or other process gases to high purity hydrogen using a standard steam methane reforming process. The new hydrogen plant is capable of producing approximately 40 MMSCF/day of hydrogen. The new hydrogen plant includes a Reformer Heater with a maximum design firing capacity of 562 MMBtu-HHV/hr. The heater is fired with natural gas, refinery fuel gas, and PSA tail gas generated within the hydrogen plant. In the reforming process, the feed stream is mixed with a relatively small volume of recycled hydrogen and preheated in a coil located in the Reformer Heater stack. The mixture is then fed to a hydrogenation reactor to convert organic sulfur compounds to H_2S. The gas is then directed to a series of absorbers where the sulfur compounds are removed. Following feed purification, the feed gas is mixed with steam and preheated in a coil located in the convection section of the Reformer Heater. The preheated steam-hydrocarbon mixture is then passed through the radiant section of the Reformer Heater. The hydrocarbons are reformed over a catalyst to produce H_2, CO, CO_2 and CH_4. The process gas exiting the Reformer is cooled and the heat is recovered resulting in the generation of high-pressure steam. To increase the overall energy efficiency of the plant, carbon monoxide in the process gas is then removed by reaction with steam to form hydrogen and carbon dioxide. This reaction occurs in the high temperature Shift Converter where CO reacts exothermically over a catalyst. The gas is cooled resulting in the generation of additional high-pressure steam. The mixture of condensate and process gas is then cooled further and separated. The condensate is recycled and retreated as boiler feed water and the process gas is routed to the Pressure Swing Absorber (PSA).

The PSA contains multiple fixed beds of solid absorbent used to remove impurities, such as CO_2, to produce high purity hydrogen (99.9 vol %). When an absorbent bed becomes saturated, it is regenerated by depressurizing and purging it with product hydrogen. This purge gas, PSA tail gas, consisting of CO_2, CO, CH_4, N_2, and H_2, will be used in the Reformer Heater as its primary fuel. It should be noted that with the exception of startup, PSA tail gas is anticipated to supply approximately 55 percent of the heat input (i.e., MMBtu/hr) to the reformer. The supplemental fuel will be natural gas or RFG. Only natural gas or RFG will be used during startup.

#1 Crude Unit Modifications GRHC completed as part of MAQP #1821-36.

The CHS refinery has two Crude Units, the #1 and #2 Crude Units. At each of the Crude Units a two-step distillation process is used to fractionate the crude into the various intermediate product streams described above. Crude oil from storage is first preheated and then treated in a desalting process to remove the solids, salts, and water found in crude oil. Downstream of the desalter, the crude oil is heated in one of two process heaters, #1 Crude Unit Preheater (CV-HTR-1) and #1 Crude Unit Main Heater (CV-HTR-2), prior to the Atmospheric Column where the crude is distilled at atmospheric pressure. In the Atmospheric Column the distillate vapors move up the column counter current to a cooler liquid stream. As the heavier hydrocarbons are being condensed from the vapors, various distillate streams, including gas oil, raw #2 diesel and raw burner fuel (i.e., #1 diesel), are drawn off the column at tray locations in relation to the temperature inside the tower. As noted above, these distillate streams are processed in downstream units (i.e., MHC and ULSD). The column overhead stream is cooled, condensed and routed to the Naphtha Hydrotreating Unit (NHT). A gaseous stream is also recovered from the overhead of the Atmospheric Column for treatment and subsequent use in the refinery fuel gas system.

The intermediate stream exiting the bottom of the Atmospheric Column is directed to the #1 Crude Unit Vacuum Heater (CV-HTR-4) where it is heated and routed to the Vacuum Column. The Vacuum Column operates in a similar fashion to the Atmospheric Column except that it operates under a vacuum so that distillation can be carried out at lower temperatures. The streams recovered from the Vacuum Column include gas oils that are processed in the MHC and the bottom stream (i.e., asphalt) that is either sold as product or processed in the refinery's Delayed Coker Unit. A distillate stream can also be recovered from the Vacuum Column and processed at the ULSD.

As part of the GRHC physical changes were made at the #1 Crude Unit to optimize and improve the operation of the unit for a wider range of crude types. In certain operating scenarios, the unit may be able to process approximately 10% more crude than its current capacity. To accomplish this, the project included the following physical changes:

- Heat exchange trains in the unit were modified.

- The vacuum processing systems were modified.

- A number of pumps and associated piping components were modified or replaced.

Mild Hydrocracker (MHC) after GRHC completed as part of MAQP #1821-36.

The existing MHC Unit currently processes gas oils from the two Crude Units and the Delayed Coker Unit. The GRHC scope included the mechanical and process control modifications required to process a range of new external feed sources in the unit. The capacity of the MHC Unit will not change as a result of the project.

FCCU Modifications after GRHC completed as part of MAQP #1821-36.

The Fluidized Catalytic Cracking Unit (FCCU) is used to convert gas oil into lighter, more valuable materials, including gasoline and fuel oils. At the FCCU preheated feed is injected into the riser where it is vaporized and cracked into smaller molecules by contact and mixing the feed with very hot powdered catalyst from the catalyst Regenerator. The hydrocarbon vapors fluidize the powdered catalyst and the mixture of hydrocarbon vapors and catalyst flows upward in the riser to the Reactor.

Within the FCCU Reactor, cyclones are used to separate the cracked product vapors from the "spent catalyst." The spent catalyst flows downward through a steam stripping section to remove any hydrocarbon from the spent catalyst prior to entering the catalyst Regenerator. The cracked hydrocarbon is then directed to the FCCU distillation process where the cracked products are separated into various intermediate product cuts. The majority of the product is a refinery gasoline component. Light cycle oil is also produced, which is typically processed through the ULSD Unit. The heaviest stream produced by the FCCU, clarified oil, is typically sold as fuel oil. Alternatively, clarified oil can be directed to the Delayed Coker Unit for additional processing or recycled back to the riser.

As a byproduct of the cracking process, carbon/coke deposits on the catalyst. As the carbon is deposited on the catalyst surface, it becomes inactive, or spent. As a result, catalyst is continuously regenerated by burning off the deposited coke in the FCCU Regenerator. The combustion of the coke is exothermic and produces a large amount of heat that is necessary for the vaporization of the feed and the endothermic cracking reactions that take place in the Riser. This catalyst regeneration process gives off primarily CO_2 and water along with parts per million levels of CO, NO_x, SO_2, VOC, and particulates. CHS utilizes an ESP to control FCCU Regenerator particulate emissions and catalyst additives to control CO and SO_2 emissions. Maintaining a high enough temperature within the Regenerator is key to minimizing CO emissions.

At the FCCU, the GRHC will included the following modifications such that a safe and stable operation can be maintained at reduced FCCU feed rates:

- Replaced the spent catalyst stripper with a new design to be more efficient at a lower operating rate.

- Replaced the primary and secondary reactor cyclones with a new design to accommodate lower operating rates.

- Replaced the regenerator cyclones with a new design to reduce catalyst losses.

- Replaced the regenerator air grid to provide a stable operation at lower rates.

- Replaced the regenerator standpipe. The new design will not result in the ability to circulate more catalyst than is currently possible.

- Replace the spent catalyst distributor within the regenerator. The new design will help stabilize CO emissions from the catalyst regeneration process.

Finally, the regenerator's air preheater was replaced because it had reached the end of its mechanical life. This natural gas direct-fired heater is used during the unit startup process to achieve the required operating temperature in the regenerator. It is also used following unit upsets or malfunctions to help return the unit to normal operations. Because the air preheater is a direct fired heater, its combustion emissions exhaust into the FCCU regenerator along with the heated air.

Light Product Railcar Loading after GRHC completed as part of MAQP #1821-36.

The CHS refinery currently ships product by truck, railcar, and pipeline. The existing railcar light product loading rack has six loading spots that are each capable of loading both gasoline and diesel product. Within the current operating philosophy, the existing facility is capable of loading a total of 12 railcars per day. The loading rack has a dedicated vapor combustion unit (VCU) that is designed to process vapors associated with a maximum loading rate of 2000 gallons per minute (gpm) of gasoline.

The GRHC included the construction of one additional loading spot at the railcar light product loading rack. The existing VCU is capable of processing the vapors associated with the increased loading capability without modification.

Amine Treatment Elements after GRHC completed as part of MAQP #1821-36.

Within a petroleum refinery, the removal of sulfur compounds from crude oil is required to meet product specifications. One of the processes used is a two-step amine treatment process used to remove sulfur compounds from process gases. In the first step, sulfur rich ("sour") gas streams are routed to an Absorber. In the absorber, H_2S is removed by contacting down flowing "lean" amine (Methyldiethanolamine or MDEA) with up flowing sour process gases. The "sweet" process gases that exit the absorber are then used as refinery fuel gas at various combustion sources or are reused in the process. In the second step, the sulfur containing ("rich") amine is routed to a Regenerator. In the regenerator, H_2S is removed from the amine in a column through contact with steam generated by reboiling. The recovered "lean" amine is recycled for reuse in the absorber. The overhead stream is separated into gaseous and liquid streams. The gaseous stream ("acid gas" - primarily H_2S) is routed to a sulfur recovery unit. The liquid stream (i.e., water) is recycled back to the amine regenerator with a small volume being purged to a sour water stripper.

The GRHC project includes the installation of additional amine treatment equipment and may modify existing treatment equipment if the existing equipment's capacity is determined to be insufficient.

Storage Tanks After GRHC Completed as part of MAQP #1821-36.

As part of the GRHC two new asphalt tanks will be constructed. Each fixed roof tank will have a capacity of 100,000 barrels and will be equipped with a steam coil. Additionally, existing Tank 114 will be changed from asphalt to diesel product service.

MUE Project and Other MAQP Changes as part of MAQP #1821-43

#2 CU Vacuum Heater (005HT0002) (New)
Coker Charge Heater (H-7502) (New)
Boiler #13 (New)
#2 CU Refinery Equipment (Modified)
MHC Refinery Equipment (Modified)
DCU Refinery Equipment (Modified)
NHT Refinery Equipment (Modified)
Boiler Area Refinery Equipment (Modified)
All Other Equipment under MAQP #1821-43 was Project Affected

#2 CU Vacuum Heater (005HT0002) replaces existing #2 CU Vacuum Heater (2CV-HTR-2)
Boiler # 9 will be permanently shut down

E. Response to CHS Comments (If received on draft permit)

Reference to PD	Comment	Department Response

F. Additional Information

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

II. Applicable Rules and Regulations

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

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

1. ARM 17.8.101 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment, including instruments and sensing devices, and shall conduct tests, emission or ambient, for such periods of time as may be necessary, using methods approved by the Department.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Montana Clean Air Act, 75-2-101, *et seq*., MCA.

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

4. ARM 17.8.110 Malfunctions. The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

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

   1. ARM 17.8.204 Ambient Air Monitoring
   2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
   3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
   4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
   5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
   6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
   7. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
   8. ARM 17.8.221 Ambient Air Quality Standard for Visibility
   9. ARM 17.8.222 Ambient Air Quality Standard for Lead
   10. ARM 17.8.223 Ambient Air Quality Standard for PM_{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 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, CHS shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions.

6. ARM 17.8.324 Hydrocarbon Emissions – Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.

7. ARM 17.8.340 Standard of Performance for New Stationary Sources. The owner or operator of any stationary source or modification, as defined and applied in 40 CFR Part 60, shall comply with the standards and provisions of 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS). The applicable NSPS Subparts include, but are not limited to:

    a. Subpart A – General Provisions apply to all equipment or facilities subject to an NSPS Subpart as listed below.

    b. Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.

    c. Subpart J – Standards of Performance for Petroleum Refineries.

d. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007 (The new gasoline/distillate truck loading rack VCU is subject only to the H_2S in fuel gas or SO_2 emission limit).

e. Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.

f. Subpart XX – Standards of Performance for Bulk Gasoline Terminals the construction or modification of which is commenced after December 17, 1980.

g. Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture.

h. Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or before November 7, 2006.

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

j. Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems.

8. <u>ARM 17.8.341 Emission Standards for Hazardous Air Pollutants</u>. This source shall comply with the standards and provisions of 40 CFR Part 61, as appropriate.

a. Subpart A – General Provisions apply to all equipment or facilities subject to a Subpart as listed below.

b. Subpart FF – National Emissions Standards for Benzene Waste Operations.

9. <u>ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories</u>. 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.

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

d. Subpart ZZZZ – National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

e. Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters.

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

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

2. <u>ARM 17.8.402 Requirements</u>. 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. <u>ARM 17.8.504 Air Quality Permit Application Fees</u>. 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. <u>ARM 17.8.505 Air Quality Operation Fees</u>. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

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

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

1. <u>ARM 17.8.740 Definitions</u>. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. <u>ARM 17.8.743 Montana Air Quality Permits--When Required</u>. This rule requires a person to obtain an air quality permit or permit modification to

construct, modify, or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. CHS has a PTE greater than 25 tons per year of SO_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, modification, 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 September 4, 2024, issue of the *Billings Gazette*, a newspaper of general circulation in the City of Billings in Yellowstone County, as proof of compliance with the public notice requirements.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving CHS of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq.*

10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or modified source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to the Department.

15. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to the Department for incineration facilities subject to 75-2-215, MCA.

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

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

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

   CHS's existing petroleum refinery in Laurel is defined as a "major stationary source" because it is a listed source with a PTE more than 100 tons per year of several pollutants (PM, SO_2, NO_x, CO, and VOCs).

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. MAQP #1821-41 does not trigger Subchapter 9.

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 MAQP #1821-46 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, Db, J, Ja, Kb, UU, XX, GGG, GGGa, and QQQ).

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

   f. This source is neither 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.

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

1. "Incinerator" means any single or multiple-chambered combustion device that burns combustible material, alone or with a supplemental fuel or catalytic combustion assistance, primarily for the purpose of removal, destruction, disposal, or volume reduction of all or any portion of the input material.

2. "Solid waste" means all putrescible and nonputrescible solid, semisolid, liquid, or gaseous wastes, including, but not limited to...air pollution control facilities.

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

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

Health Risk Assessment (MAQP #1821-04)

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

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

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

*The reference concentration for Benzene is 71 $\mu g/m^3$ (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.

Health Risk Assessment (MAQP #1821-13)

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

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

Chemical Compound	Modeled 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
Naphthalene	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 1×10^{-6}. The RBC concentration for benzene is listed as 2.3×10^{-1}, which is higher than the modeled concentration for benzene. Therefore, the Department determined that the health risk assessment model demonstrated negligible risk to public health in this case.

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

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

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

Chemical Compound	Modeled Conc. 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. Updated information provided to the Department on October 24, 2006, revised the modeled concentration of carbon disulfide to 3.05E-02, which did not affect this determination. Therefore, the Department determined that the health risk assessment model demonstrated negligible risk to public health in this case.

Health Risk Assessment (MAQP #1821-27)

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

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

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

Loading Rack VCU - Screening Level Concentrations

Annual Average, 0.1 x One Hour Maximum VOCs **[µg/m³]** (a) =	7.055			
Chemical	**Annual Average [µg/m³]**	**Cancer Chronic(b) [µg/m³]**	**Non-Cancer Chronic(c) [µg/m³]**	**Non-Cancer Acute(c) [µg/m³]**
Benzene	6.35E-02	1.20E-02	0.71	N/A
Ethylbenzene	7.10E-03	N/A	10.0	N/A
n-Hexane	1.13E-01	N/A	2.0	N/A
Toluene	9.17E-02	N/A	4.0	N/A
m-Xylene	3.53E-02	N/A	3.0	44.0

(a) Annual Maximum concentration calculated by apply a scaling factor of 0.1, as recommended by MDEQ and EPA's Screening Procedures for Estimating the Air Quality Impact of Stationary Sources (October 1992, EPA-454/R-92-019)
(b) ARM 17.8.770, Table 1.
(c) ARM 17.8.770, Table 2.

Because the peak annual average modeled concentrations of benzene exceeded the ARM 17.8.770 screening-level concentration thresholds, a more refined risk assessment was performed for inhalation exposure to this HAP. General methodology described in EPA's Human Health Risk Assessment Protocol (HHRAP) was followed.[3]

The peak annual average modeled concentration of benzene was multiplied by a Unit Risk Factor (URF) published by EPA for this type of analysis.[4] The result of this calculation conservatively estimates the probability of developing cancer from exposure to a pollutant or a mixture of pollutants over a 70-year lifetime, usually expressed as the number of additional cancer cases in a given number of people. For example, a cancer risk value of 1.0E-06 is interpreted as a one-in-a-million lifetime probability of the exposure resulting in cancer.

The annual average benzene concentration was divided by its respective Reference Concentrations (RfC) to determine individual non-cancer hazard quotients. RfCs have been developed to compare effects of a theoretical exposure to a standard exposure level with known effects. They represent estimates of daily concentrations that, when exposure persists over a given period of time (generally 70 years for chronic effects), adverse effects are considered unlikely. The individual hazard quotients were also summed to derive a cumulative hazard index value. Results of the cancer risk and non-cancer hazard assessments are presented below.

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

[4] See Table 1 at this EPA web site: http://www.epa.gov/ttn/atw/toxsource/summary.html.

Calculated Risk Summary

		EPA Risk Factors[a]			
Chemical	**Annual Average Concentration (µg/m³)**	**Cancer, Chronic (per µg/m³)**	**Non-Cancer Chronic HQ (µg/m³)**	**Calculated Cancer Risk**	**Calculated Non-Cancer Chronic HQ**
Benzene	0.0635	7.80E-06	30.0	4.95E-07	2.12E-03
			Total =	4.95E-07	2.12E-03

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

ARM 17.8.740(16) defines "negligible risk to the public health, safety, and welfare and to the environment" as "an increase in excess lifetime cancer risk of less than 1.0 x10^{-6}, for any individual pollutant, and 1.0 x 10^{-5}, for the aggregate of all pollutants, and an increase in the sum of the non-cancer hazard quotients [e.g.,, hazard index] for all pollutants with similar toxic effects of less than 1.0, as determined by a human health risk assessment conducted according to ARM 17.8.767." As shown, the results of this analysis are all well below these regulatory threshold values.

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

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

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

Health Risk Assessment (MAQP #1821-33)

In the MAQP #1821-33 permitting action, CHS proposed a Replacement Refinery Flare and a new ammonia combustor associated with the Zone D Sour Water Stripper process. The Replacement Refinery Flare was determined exempt from the requirements of ARM 17.8.770, as the definition of an incinerator provided in MCA was intended to exclude such flares as described in MCA 75-2-103(12)(b)(i). The purpose of a refinery flare is to reduce the impact to human health and the environment from the emissions of process gasses by destruction of those gases through combustion. The Main Refinery Flare serves as an important safety device for refinery operations, and is regulated under 40 CFR 60 Subpart Ja, 40 CFR 60.18, 40 CFR 63.11, and subject to air quality permit review.

The new ammonia combustor is associated with a new two stage sour water stripper. The sour water stripper results in two waste gas streams, one rich in reduced sulfur compounds, and one rich in ammonia. The waste gas stream rich in reduced sulfur compounds will be treated at the existing Sulfur Recovery Units, which have been previously permitted and reviewed at the permitted levels with respect to the Incineration requirements. However, as the ammonia stream will be sent to a new ammonia combustor, this combustion process was determined to require review under ARM 17.8.770.

Due to the high moisture content of the ammonia stream, supplemental natural gas must be used to support the combustion of the stream. The total maximum heat input associated with both the natural gas and ammonia streams combined were utilized to estimate HAP emissions from this process for purposes of review under ARM 17.8.770. HAP emissions were estimated using AP-42 HAP emissions factors for natural gas. As shown in Table 2 below, given the orders of magnitude below screening level concentrations of ARM 17.8.770, this approach was determined acceptable.

Exposure from inhalation was determined as the only appropriate pathway to consider given the pollutants and nature and concentration of emissions expected. AERMOD Modeling was conducted to determine maximum exposure concentrations for the HAP pollutants identified. AERMOD inputs are summarized in Table 1 below.

The results of the maximum exposure levels of HAPs compared to the screening levels of ARM 17.8.770 are summarized in Table 2 below.

TABLE 1		
Model Input	**Input Value**	**Input Value Justification**
Source Parameters		
Source Type	Point	The flame is enclosed in the SWS. Modeling the unit as a flare is therefore not appropriate.
Pollutant	Other	
Point Source Type	Default	
Rural/Urban	Rural	The land use of the surrounding area was determined to be less than 50% I1, I2, C1, R2 and R3, based upon the land use typing scheme of Auer. The model was therefore not run in urban mode.
Emission Rate	1.0 lb/hr	A unit emission rate was modeled such that individual pollutant impacts could be easily scaled from the results.
Stack Height	170 feet	Provided by manufacturer.
Stack Inside Diameter	2.0 feet	Provided by manufacturer.
Exit Velocity	75 ft/sec	Provided by manufacturer.
Exit Temperature	400 °F	Provided by manufacturer.
Met Data		
AERMET		Five years (2007-2011) of surface meteorological data from Billings, MT and upper air data from Great Falls, MT were used. The AERMET meteorological processor was used to develop the meteorological data along with EPA's AERSURFACE and AERMINUTE pre-processor programs.
Receptor Options		
Fenceline	50m	Receptors were located along the facility fenceline with a 50m spacing.
Cartesian Grids	100 & 500m	Two Cartesian grids were used. One with 100m spacing that extended from the fence to 1500m from the fence. The second had receptors spaced at 500m and extended from 1500 to 15000m. Additional receptors were spaced at 100m in the high elevations where elevated concentrations were noted.
Flagpole Height	0	Receptor concentrations were predicted at ground level. No flagpole receptors were used.
Terrain		
Terrain Options		The terrain processor AERMAP was used to calculate receptor elevations and hill height scale factors. One third arcsecond National Elevation Data were used to derive these values.

TABLE 2		
Pollutant	**Annual SWSI Concentration (µg/m³)**	**ARM 17.8.770 Screening Concentration (µg/m³)**
17.8.770 Table 1 HAPs		
Benzene	2.22E-06	1.20E-02
Formaldehyde	7.94E-05	7.69E-03
Benzo(a)anthracene	1.90E-09	5.88E-05
Benzo(b)fluoranthene	1.90E-09	5.88E-05
Benzo(a)pyrene	1.27E-09	5.88E-05
Dibenz(a,h)anthracene	1.27E-09	5.88E-05
Indeno(1,2,3-cd)pyrene	1.90E-09	5.88E-05
17.8.770 Table 2 HAPs		
Hexane	1.90E-03	2.0
Naphthalene	6.45E-07	0.14
Toluene	3.59E-06	4.0
Arsenic Compounds	2.11E-07	5.00E-03
Beryllium	1.27E-08	4.80E-05
Cadmium Compounds	1.16E-06	3.50E-02
Chromium Compounds	1.48E-06	2.00E-05
Lead Compounds	5.28E-07	1.50E-02
Manganese Compounds	4.01E-07	5.00E-04
Mercury Compounds	2.75E-07	3.00E-03
Nickel Compounds	2.22E-06	2.40E-03
Selenium Compounds	2.54E-08	5.00E-03

Table 2 above demonstrates all pollutant levels were determined to be significantly below the screening levels of ARM 17.8.770. In accord with ARM 17.8.770, there would be negligible risk to public health from the ammonia combustor emissions. Environmental effects unrelated to human health were not considered in determining compliance with the negligible risk standard, but were evaluated as required by the Montana Environmental Policy Act, in determining compliance with all applicable rules or other requirements requiring protection of public health, safety, welfare and the environment. The Montana Environmental Policy Act review is attached to MAQP #1821-33, with no significant impacts determined, based on the extremely low level of concentrations expected.

Health Risk Assessment (MAQP #1821-41)

CHS has presented a human health risk assessment regarding the proposed thermal combustor. Destruction efficiencies were assumed to be 98 percent which is considered to be the minimum generally expected for incinerators. ARM 17.8.770(1)(c) exempts individual pollutants from the requirements to perform a human health risk assessment if inhalation is the only exposure pathway and ambient concentrations are below levels in Table 1 or Table 2 of the rule. Inhalation is the only exposure pathway. Results of screening modeling demonstrate that no pollutants are above levels in Table 1 or Table 2 of the rule.

Pollutant	Maximum Annual Impact[a] (µg/m³)	Maximum 1-hr Impact[b] (µg/m³)	Table 1 Cancer Screen Level[c] (µg/m³)	Table 2 Non-cancer Chronic Screen Level[d] (µg/m³)	Table 2 Non-cancer Acute Screen Level (µg/m³)	Maximum Impact below Table 1 Cancer Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Chronic Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Acute Screen Level (Yes/No)
1 HYDROXY 2 METHYL BENZENE (o-cresol)	7.71E-06	2.88E-04	-	1.80E+00	-	-	Yes	-
1 HYDROXY 3 METHYLBENZENE (m-cresol)	2.30E-06	8.61E-05	-	-	-	-	-	-
1 HYDROXY 4 METHYLBENZENE (p-cresol)	1.47E-05	5.50E-04	-	-	-	-	-	-
1,1 DICHLOROETHENE vinylidene chloride	1.32E-05	4.95E-04	2.00E-03	3.20E-01	-	Yes	Yes	-
1,2 DICHLOROBENZENE (-o)	4.64E-07	1.73E-05	-	-	-	-	-	-
1,3 DICHLOROBENZENE (-m)	9.55E-07	3.57E-05	-	-	-	-	-	-
1,4 DICHLOROBENZENE (-p)	9.81E-07	3.67E-05	9.09E-03	8.00E+00	-	Yes	Yes	-
DICHLOROBENZENE (mixed isomers)	1.22E-07	4.55E-06	-	-	-	-	-	-
1,2 DICHLOROETHENE trans	4.29E-06	1.60E-04	-	-	-	-	-	-
1,2,4-TRIMETHYLBENZENE	3.60E-04	1.35E-02	-	-	-	-	-	-
1-METHYL NAPHTHALENE	2.04E-04	7.61E-03	-	-	-	-	-	-
2 BUTANONE (methyl ethyl ketone, MEK)	1.94E-06	7.24E-05	-	1.00E+01	-	-	Yes	-
2 METHYLNAPHTHALENE	2.12E-04	7.93E-03	-	-	-	-	-	-
3-METHYLCHLORANTHRENE	1.83E-10	6.83E-09	-	-	-	-	-	-
7,12-DIMETHYLBENZ(A)ANTHRACENE	1.62E-09	6.07E-08	-	-	-	-	-	-
ACENAPHTHENE	1.83E-10	6.83E-09	-	-	-	-	-	-

Pollutant	Maximum Annual Impact[a] (µg/m³)	Maximum 1-hr Impact[b] (µg/m³)	Table 1 Cancer Screen Level[c] (µg/m³)	Table 2 Non-cancer Chronic Screen Level[d] (µg/m³)	Table 2 Non-cancer Acute Screen Level (µg/m³)	Maximum Impact below Table 1 Cancer Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Chronic Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Acute Screen Level (Yes/No)
ANTHRACENE	2.44E-10	9.11E-09	-	-	-	-	-	-
ARSENIC	2.03E-08	7.59E-07	2.3256e-05	5.00E-03	-	Yes	Yes	-
BARIUM	4.46E-07	1.67E-05	-	-	-	-	-	-
BENZENE	1.44E-03	5.38E-02	1.20E-02	7.10E-01	-	Yes	Yes	-
BENZO(A)ANTHRACENE	1.83E-10	6.83E-09	5.88E-05	-	-	Yes	-	-
BENZO(A)PYRENE	1.22E-10	4.55E-09	5.88E-05	-	-	Yes	-	-
BENZO(B)FLUORANTHENE	1.83E-10	6.83E-09	5.88E-05	-	-	Yes	-	-
BENZO(G,H,I)PERYLENE	1.22E-10	4.55E-09	-	-	-	-	-	-
BENZO(K)FLUORANTHENE	1.83E-10	6.83E-09	5.88E-05	-	-	Yes	-	-
BERYLLIUM	1.22E-09	4.55E-08	4.17E-05	4.80E-05	-	Yes	Yes	-
BUTANE	2.13E-04	7.97E-03	-	-	-	-	-	-
BUTYL BENZENE	4.01E-05	1.50E-03	-	-	-	-	-	-
CADMIUM	1.12E-07	4.17E-06	5.56E-05	3.50E-02	-	Yes	Yes	-
CHLOROBENZENE	2.11E-06	7.89E-05	-	7.00E-01	-	-	Yes	-
CHLOROFORM	4.48E-06	1.68E-04	4.35E-03	3.50E-01	-	Yes	Yes	-
CHROMIUM	5.68E-09	2.12E-07	8.33E-06	2.00E-05	-	Yes	Yes	-
CHROMIUM VI	5.68E-09	2.12E-07	-	-	-	-	-	-
CHRYSENE	1.22E-06	4.57E-05	-	-	-	-	-	-
COBALT	8.52E-09	3.19E-07	-	-	-	-	-	-
COPPER	8.63E-08	3.23E-06	-	-	-	-	-	-
CUMENE (isopropylbenzene)	1.06E-04	3.97E-03	-	-	-	-	-	-

Pollutant	Maximum Annual Impact[a] (µg/m^3)	Maximum 1-hr Impact[b] (µg/m^3)	Table 1 Cancer Screen Level[c] (µg/m^3)	Table 2 Non-cancer Chronic Screen Level[d] (µg/m^3)	Table 2 Non-cancer Acute Screen Level (µg/m^3)	Maximum Impact below Table 1 Cancer Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Chronic Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Acute Screen Level (Yes/No)
CYCLOHEXANE	9.09E-03	3.40E-01	-	-	-	-	-	-
CYMENE,para	1.72E-05	6.41E-04	-	-	-	-	-	-
DIBENZO(A,H)ANTHRACENE	1.22E-10	4.55E-09	5.88E-05	-	-	Yes	-	-
DICHLOROETHANE(1,1) ethylidenedichloride	2.65E-06	9.90E-05	-	-	-	-	-	-
DICHLOROETHYLENE(1,2) cis	2.59E-06	9.70E-05	-	-	-	-	-	-
ETHANE	3.15E-04	1.18E-02	-	-	-	-	-	-
ETHENYLBENZENE (styrene)	1.01E-06	3.79E-05	-	1.00E+01	-	-	Yes	-
ETHYLBENZENE	3.60E-04	1.35E-02	-	1.00E+01	-	-	Yes	-
FLUORANTHENE	3.04E-10	1.14E-08	-	-	-	-	-	-
FLUORENE	2.84E-10	1.06E-08	-	-	-	-	-	-
FORMALDEHYDE	7.61E-06	2.85E-04	7.69E-03	3.60E-02	3.70	Yes	Yes	Yes
HEXANE(-n)	2.48E-02	9.26E-01	-	2.00E+00	-	-	Yes	-
INDENO(1,2,3-CD)PYRENE	1.83E-10	6.83E-09	5.88E-05	-	-	Yes	-	-
LEAD	5.07E-08	1.90E-06	-	1.50E-02	-	-	Yes	-
MANGANESE	3.86E-08	1.44E-06	-	5.00E-04	-	-	Yes	-
MERCURY	2.64E-08	9.86E-07	-	3.00E-03	0.30	-	Yes	Yes
MOLYBDENUM	1.12E-07	4.17E-06	-	-	-	-	-	-
NAPHTHALENE	4.64E-05	1.74E-03	-	1.40E-01	-	-	Yes	-
NICKEL	2.13E-07	7.97E-06	3.85E-04	2.40E-03	0.01	Yes	Yes	Yes
PENTANE	2.64E-04	9.86E-03	-	-	-	-	-	-
PHENANTHRENE	1.49E-06	5.59E-05	-	-	-	-	-	-

Pollutant	Maximum Annual Impact[a] (µg/m^3)	Maximum 1-hr Impact[b] (µg/m^3)	Table 1 Cancer Screen Level[c] (µg/m^3)	Table 2 Non-cancer Chronic Screen Level[d] (µg/m^3)	Table 2 Non-cancer Acute Screen Level (µg/m^3)	Maximum Impact below Table 1 Cancer Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Chronic Screen Level (Yes/No)	Maximum Impact below Table 2 Non-cancer Acute Screen Level (Yes/No)
PHENOL	8.07E-06	3.02E-04	-	4.50E-01	-	-	Yes	-
PROPANE	1.62E-04	6.07E-03	-	-	-	-	-	-
PROPANONE (acetone)	1.72E-16	6.43E-15	-	-	-	-	-	-
PROPYL(-n) BENZENE	1.28E-04	4.77E-03	-	-	-	-	-	-
PYRENE	5.07E-10	1.90E-08	-	-	-	-	-	-
sec BUTYLBENZENE	2.79E-05	1.05E-03	-	-	-	-	-	-
SELENIUM	2.44E-09	9.11E-08	-	5.00E-03	0.02	-	Yes	Yes
TOLUENE	1.81E-03	6.77E-02	-	4.00E+00	-	-	Yes	-
TRIMETHYLBENZENE (1,3,5)	7.96E-05	2.98E-03	-	-	-	-	-	-
VANADIUM	2.33E-07	8.73E-06	-	-	-	-	-	-
XYLENE	1.55E-03	5.81E-02	-	3.00E+00	44.00	-	Yes	Yes
ZINC	2.94E-06	1.10E-04	-	-	-	-	-	-

CHS also conducted a more refined risk assessment for those HAPs not listed in ARM 17.8.770. Cancer and Non-cancer risks were calculated according to EPA's Human Health Risk Assessment Protocol. Results are shown below.

Pollutant	Maximum Annual Impact[a] (µg/m^3)	Maximum 1-hr Impact[b] (µg/m3)	Chronic Inhalation Cancer Dose Response Value[c] (µg/m^3)$^{-1}$	Calculated Cancer Risk	Chronic Inhalation Non-cancer Dose Response Value (RfC)[c] (mg/m^3)	Acute Inhalation Non-cancer Dose Response Value (RfC)[c] (mg/m^3)	Calculated Non-cancer Risk (HQ)	Calculated Acute Non-cancer Risk (HQ)
1 HYDROXY 2 METHYL BENZENE (o-cresol)	7.71E-06	2.88E-04	-	-	-	110	d	2.62E-09
1 HYDROXY 3 METHYLBENZENE (m-cresol)	2.30E-06	8.61E-05	-	-	-	-	-	-
1 HYDROXY 4 METHYLBENZENE (p-cresol)	1.47E-05	5.50E-04	-	-	-	-	-	-
1,1 DICHLOROETHENE vinylidene chloride	1.32E-05	4.95E-04	-	d	2.00E-01	20	d	2.47E-08
1,2 DICHLOROBENZENE (-o)	4.64E-07	1.73E-05	-	-	-	-	-	-
1,3 DICHLOROBENZENE (-m)	9.55E-07	3.57E-05	-	-	-	-	-	-
1,4 DICHLOROBENZENE (-p)	9.81E-07	3.67E-05	1.10E-05	d	8.00E-01	90	d	4.08E-10
DICHLOROBENZENE (mixed isomers)	1.22E-07	4.55E-06	-	-	-	-	-	-
1,2 DICHLOROETHENE trans	4.29E-06	1.60E-04	-	-	-	-	-	-
1,2,4-TRIMETHYLBENZENE	3.60E-04	1.35E-02	-	-	-	-	-	-
1-METHYL NAPHTHALENE	2.04E-04	7.61E-03	-	-	-	6	-	1.27E-06
2 BUTANONE (methyl ethyl ketone, MEK)	1.94E-06	7.24E-05	-	-	-	-	d	-
2 METHYLNAPHTHALENE	2.12E-04	7.93E-03	-	-	-	6	-	1.32E-06
3-METHYLCHLORANTHRENE	1.83E-10	6.83E-09	6.30E-03	1.15E-12	-	0.2	-	3.41E-11
7,12-DIMETHYLBENZ(A)ANTHRACENE	1.62E-09	6.07E-08	7.10E-02	1.15E-10	-	-	-	-
ACENAPHTHENE	1.83E-10	6.83E-09	-	-	-	0.4	-	1.71E-11
ANTHRACENE	2.44E-10	9.11E-09	-	-	-	-	-	-
ARSENIC	2.03E-08	7.59E-07	4.30E-03	d	1.50E-05	0.0002	d	3.79E-06
BARIUM	4.46E-07	1.67E-05	-	-	-	-	-	-

Pollutant	Maximum Annual Impact[a] (µg/m^3)	Maximum 1-hr Impact[b] (µg/m3)	Chronic Inhalation Cancer Dose Response Value[c] (µg/m^3)$^{-1}$	Calculated Cancer Risk	Chronic Inhalation Non-cancer Dose Response Value (RfC)[c] (mg/m^3)	Acute Inhalation Non-cancer Dose Response Value (RfC)[c] (mg/m^3)	Calculated Non-cancer Risk (HQ)	Calculated Acute Non-cancer Risk (HQ)
BENZENE	1.44E-03	5.38E-02	7.80E-06	d	3.00E-02	1.3	d	4.14E-05
BENZO(A)ANTHRACENE	1.83E-10	6.83E-09	1.10E-04	d	-	0.1	-	6.83E-11
BENZO(A)PYRENE	1.22E-10	4.55E-09	1.10E-03	d	-	0.2	-	2.28E-11
BENZO(B)FLUORANTHENE	1.83E-10	6.83E-09	1.10E-04	d	-	0.2	-	3.41E-11
BENZO(G,H,I)PERYLENE	1.22E-10	4.55E-09	-	-	-	10	-	4.55E-13
BENZO(K)FLUORANTHENE	1.83E-10	6.83E-09	1.10E-04	d	-	0.2	-	3.41E-11
BERYLLIUM	1.22E-09	4.55E-08	2.40E-03	d	2.00E-05	0.025	d	1.82E-09
BUTANE	2.13E-04	7.97E-03	-	-	-	-	-	-
BUTYL BENZENE	4.01E-05	1.50E-03	-	-	-	-	-	-
CADMIUM	1.12E-07	4.17E-06	1.80E-03	d	1.00E-05	0.9	d	4.64E-09
CHLOROBENZENE	2.11E-06	7.89E-05	-	-	1.00E+00	46	d	1.72E-09
CHLOROFORM	4.48E-06	1.68E-04	-	d	9.80E-02	0.15	d	1.12E-06
CHROMIUM	5.68E-09	2.12E-07	-	d	-	1	d	2.12E-10
CHROMIUM VI	5.68E-09	2.12E-07	1.20E-02	6.82E-11	1.00E-04	1.5	5.68E-08	1.42E-10
CHRYSENE	1.22E-06	4.57E-05	1.10E-05	1.35E-11	-	0.2	-	2.29E-07
COBALT	8.52E-09	3.19E-07	-	-	1.00E-04	2	8.52E-08	1.59E-10
COPPER	8.63E-08	3.23E-06	-	-	-	-	-	-
CUMENE (isopropylbenzene)	1.06E-04	3.97E-03	-	-	4.00E-01	250	2.65E-07	1.59E-08
CYCLOHEXANE	9.09E-03	3.40E-01	-	-	-	-	-	-
CYMENE,para	1.72E-05	6.41E-04	-	-	-	-	-	-
DIBENZO(A,H)ANTHRACENE	1.22E-10	4.55E-09	1.20E-03	d	-	10	-	4.55E-13
DICHLOROETHANE(1,1) ethylidenedichloride	2.65E-06	9.90E-05	1.60E-06	4.24E-12	5.00E-01	1200	5.29E-09	8.25E-11

Pollutant	Maximum Annual Impact[a] (μg/m^3)	Maximum 1-hr Impact[b] (μg/m3)	Chronic Inhalation Cancer Dose Response Value[c] (μg/m^3)$^{-1}$	Calculated Cancer Risk	Chronic Inhalation Non-cancer Dose Response Value (RfC)[c] (mg/m^3)	Acute Inhalation Non-cancer Dose Response Value (RfC)[c] (mg/m^3)	Calculated Non-cancer Risk (HQ)	Calculated Acute Non-cancer Risk (HQ)
DICHLOROETHYLENE(1,2) cis	2.59E-06	9.70E-05	-	-	-	-	-	-
ETHANE	3.15E-04	1.18E-02	-	-	-	-	-	-
ETHENYLBENZENE (styrene)	1.01E-06	3.79E-05	-	-	1.00E+00	21	d	1.80E-09
ETHYLBENZENE	3.60E-04	1.35E-02	2.50E-06	9.01E-10	1.00E+00	140	d	9.62E-08
FLUORANTHENE	3.04E-10	1.14E-08	-	-	-	0.005	-	2.28E-09
FLUORENE	2.84E-10	1.06E-08	-	-	-	7.5	-	1.42E-12
FORMALDEHYDE	7.61E-06	2.85E-04	1.30E-05	d	9.80E-03	0.055	d	d
HEXANE(-n)	2.48E-02	9.26E-01	-	-	7.00E-01	390	d	2.37E-06
INDENO(1,2,3-CD)PYRENE	1.83E-10	6.83E-09	1.10E-04	d	-	0.15	-	4.55E-11
LEAD	5.07E-08	1.90E-06	-	-	1.50E-04	10	d	1.90E-10
MANGANESE	3.86E-08	1.44E-06	-	-	3.00E-04	50	d	2.88E-11
MERCURY	2.64E-08	9.86E-07	-	-	3.00E-04	0.0006	d	d
MOLYBDENUM	1.12E-07	4.17E-06	-	-	-	-	-	-
NAPHTHALENE	4.64E-05	1.74E-03	3.40E-05	1.58E-09	3.00E-03	130	d	1.34E-08
NICKEL	2.13E-07	7.97E-06	-	d	9.00E-05	1	d	d
PENTANE	2.64E-04	9.86E-03	-	-	-	-	-	-
PHENANTHRENE	1.49E-06	5.59E-05	-	-	-	0.4	-	1.40E-07
PHENOL	8.07E-06	3.02E-04	-	-	2.00E-01	5.8	d	5.21E-08
PROPANE	1.62E-04	6.07E-03	-	-	-	-	-	-
PROPANONE (acetone)	1.72E-16	6.43E-15	-	-	-	-	-	-
PROPYL(-n) BENZENE	1.28E-04	4.77E-03	-	-	-	-	-	-
PYRENE	5.07E-10	1.90E-08	-	-	-	15	-	1.26E-12

Pollutant	Maximum Annual Impact[a] (µg/m^3)	Maximum 1-hr Impact[b] (µg/m3)	Chronic Inhalation Cancer Dose Response Value[c] (µg/m^3)$^{-1}$	Calculated Cancer Risk	Chronic Inhalation Non-cancer Dose Response Value (RfC)[c] (mg/m^3)	Acute Inhalation Non-cancer Dose Response Value (RfC)[c] (mg/m^3)	Calculated Non-cancer Risk (HQ)	Calculated Acute Non-cancer Risk (HQ)
sec BUTYLBENZENE	2.79E-05	1.05E-03	-	-	-	-	-	-
SELENIUM	2.44E-09	9.11E-08	-	-	2.00E-02	0.1	d	d
TOLUENE	1.81E-03	6.77E-02	-	-	5.00E+00	37	d	1.83E-06
TRIMETHYLBENZENE (1,3,5)	7.96E-05	2.98E-03	-	-	-	-	-	-
VANADIUM	2.33E-07	8.73E-06	-	-	-	-	-	-
XYLENE	1.55E-03	5.81E-02	-	-	1.00E-01	22	d	d
ZINC	2.94E-06	1.10E-04	-	-	-	-	-	-
Total Chronic Risk				3.02E-08			1.70E-05	

[a] Maximum annual impact modeled at 1 lb/hr scaled by HAP hourly emission rate.

[b] Maximum hourly impact modeled at 1 lb/hr scaled by HAP hourly emission rate.

[c] Dose-response values are available at https://www.epa.gov/fera/dose-response-assessment-assessing-health-risks-associated-exposure-hazardous-air-pollutants.

[d] HAP screened out of evaluation

- Denotes no available risk factor

ARM 17.8.740(16) defines “negligible risk to the public health, safety, and welfare and to the environment” as “an increase in excess lifetime cancer risk of less than 1.0 x10-6, for any individual pollutant, and 1.0 x 10-5, for the aggregate of all pollutants, and an increase in the sum of the noncancer hazard quotients [i.e., hazard index] for all pollutants with similar toxic effects of less than 1.0, as determined by a human health risk assessment conducted according to ARM 17.8.767.” As shown, the results of this analysis are below these regulatory threshold values.

III. BACT Determination

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

For this portion of the BACT analysis, updated information on the revised Multi-Unit Expansion Project (RMUE)is presented, as some previous BACT determinations are no longer subject to Prevention of Significant Deterioration or PSD BACT due to the scope changes in the project. The BACT analyses for the proposed action generally use a top-down, 5-step BACT process, as follows:

Step 1: Identify All Control Technologies
Steps 2 Eliminate Technically Infeasible Options

Step 3: Rank Available Control Technologies by Control Effectiveness
Step 4: Evaluate Most Effective Controls and Document Results

Step 5: Select BACT

A summary of the BACT analysis for the RMUE project is included below. The summary table, BACT-1, below, provides the processes that were previously covered by BACT under MAQP #1821-43 and that are covered by BACT in this revised application. Table BACT-2, below, shows the emissions unit/pollutant controls and BACT limits for the new and modified RMUE emissions units. Project affected units are not subject to BACT requirements.

Table BACT-1. Summary of New, Modified, and Non-Modified MUE Emissions Units and their BACT Applicability

	2020 MUE Application			**2024 MUE Application** [a]	
Emissions Unit	**New, Modified, Project Affected**	**PSD BACT**	**ARM 17.8.752 BACT**	**New, Modified, Project Affected**	**ARM 17.8.752 BACT**
#2CU Vacuum Heater (005HT0002)	New	NOx, PM_{10}, $PM_{2.5}$, GHG	SO_2, PM, CO, VOC, H_2SO_4	New	All criteria pollutants [b]
~~Coker Charge Heater (H-7502)~~	~~New~~	~~NOx, PM_{10}, $PM_{2.5}$, GHG~~	~~SO_2, PM, CO, VOC, H_2SO_4~~	Removed from project scope	
~~Boiler 13~~	~~New~~	~~NOx, PM_{10}, $PM_{2.5}$, GHG~~	~~SO_2, PM, CO, VOC, H_2SO_4~~	Removed from project scope	
#2CU Main Heater (005HT0001)	Project Affected	No	No	Modified	All criteria pollutants [b]
#2 CU Refinery Equipment	Modified	~~GHG~~	VOC	Modified	VOC
MHC Refinery Equipment	Modified	~~GHG~~	VOC	Modified	VOC
DCU Refinery Equipment	Modified	~~GHG~~	VOC	Modified	VOC
NHT Refinery Equipment	Modified	~~GHG~~	VOC	Modified	VOC
Boiler Area Refinery Equipment	Modified	~~GHG~~	VOC	Removed from project scope	
Zone A SRP	Project Affected	No	No	Modified	SO_2
Zone D SRP	Project Affected	No	No	Modified	SO_2
Platformer Heater	Project Affected	No	No	Project Affected	No
Platformer Debutanizer Heater	Project Affected	No	No	Project Affected	No
Platformer Splitter Reboiler	Project Affected	No	No	Project Affected	No
FCC Charge Heater	Project Affected	No	No	Project Affected	No
H-201 Reactor Charge Heater	Project Affected	No	No	Project Affected	No
H-202 Fractionator Feed Heater	Project Affected	No	No	Project Affected	No
Alkylation Hot Oil Heater	Project Affected	No	No	Project Affected	No
FCCU Regenerator	Project Affected	No	No	Project Affected	No
Hydrogen Reformer H-101	Project Affected	No	No	Project Affected	No
Hydrogen Reformer H-102	Project Affected	No	No	Project Affected	No
Hydrogen Reformer H-1001	Project Affected	No	No	Project Affected	No
#3 Hydrogen Reformer	Project Affected	No	No	Project Affected	No
Coker Drum Steam Vent	Project Affected	No	No	Project Affected	No
Coke Handling	Project Affected	No	No	Project Affected	No
Coke Pile	Project Affected	No	No	Project Affected	No
Coke Trucking	Project Affected	No	No	Project Affected	No

	2020 MUE Application			2024 MUE Application [a]	
Emissions Unit	**New, Modified, Project Affected**	**PSD BACT**	**ARM 17.8.752 BACT**	**New, Modified, Project Affected**	**ARM 17.8.752 BACT**
Storage Tanks	Project Affected	No	No	Project Affected	No
Zone E SRP	Project Affected	No	No	No longer project affected.	
2SSWS Ammonia Combustor	Project Affected	No	No	Project Affected	No
Railcar Light Product Loading	Project Affected	No	No	Project Affected	No

[a] The RMUE does not result in an emissions increase of a regulated NSR pollutant that is greater than the significant emissions increase rate. As a result, none of the new or modified emissions units are subject to the control technology review requirement of ARM 17.8.819(3).

[b] All criteria pollutants except Pb

Table BACT-2. Summary of Proposed BACT Controls and Limits

Emissions Unit	Pollutant	Control Technology	Limit/Averaging Time	Compliance Method
#2 Crude Unit Vacuum Heater (005HT0002) (Construction Completed in 2021)				
	NOx	Ultra Low NOx Burners (ULNB)	• 1.05 lb/hr (stack test)	EPA reference method 7E
	PM/PM_{10}/$PM_{2.5}$	Good Combustion Design & Operation	• Proper design and good combustion practices	Compliance via recordkeeping per 40 CFR Subpart DDDDD
	SO_2 and H_2SO_4	Amine treating of RFG.	• 60 ppm H_2S (365-day roll) • 162 ppm H_2S (3-hour roll)	H_2S CEM operated in compliance with 40 CFR 60.
	CO	Good Combustion Design & Operation	• 1.05 lb/hr (stack test)	EPA reference method 10
	VOC	Good Combustion Design & Operation	• Proper design and good combustion practices	Compliance with CO limit
#2 Crude Unit Main Heater (005HT0001)				
	NOx	Low NOx Burners (LNB)	• 2.81 lb/hour (stack test)	EPA reference method 7E
	PM/PM_{10}/$PM_{2.5}$	Good Combustion Design & Operation	• Proper design and good combustion practices	Compliance via recordkeeping per 40 CFR Subpart DDDDD
	SO_2 and H_2SO_4	Amine treating of RFG.	• Refinery fuel gas H2S content of 60 ppmv (365-day rolling average) • Refinery fuel gas H2S content of 162 ppmv (3-hr roll)	Compliance shall be demonstrated in accordance with 40 CFR 60.107a(a).
	CO	Good Combustion Design & Operation	• 2.81 lb/hour (stack test)	EPA reference method 10
	VOC	Good Combustion Design & Operation	• Proper design and good combustion practices	Compliance with CO limit
Coker Charge Heater H-7502 – Removed from project scope.				
Boiler 13 – Removed from project scope.				

Emissions Unit	Pollutant	Control Technology	Limit/Averaging Time	Compliance Method
Equipment Leaks – Fugitive Components				
#2 Crude Unit Fugitive Components				
	VOC	Enhanced Leak Detection & Repair	• An effective LDAR program meeting the requirements of NSPS Subpart GGGa.	Recordkeeping and Reporting
Mild Hydrotreater (MHC) Fugitive Components				
	VOC	Enhanced Leak Detection & Repair	• An effective LDAR program meeting the requirements of NSPS Subpart GGGa.	Recordkeeping and Reporting
Naphtha Hydrotreating Unit (NHTU) Fugitive Components (Construction Completed in 2021)				
	VOC	Enhanced Leak Detection & Repair	• An effective LDAR program meeting the requirements of NSPS Subpart GGGa.	Recordkeeping and Reporting
Wastewater Collection System (WCS)				
#2 Crude Unit Wastewater Collection System				
	VOC	WCS monitoring program	• An effective monitoring program meeting the requirements of NSPS subpart QQQ standard applicable to new and modified individual drain systems. .	Recordkeeping and Reporting
Mild Hydrocracker (MHC) Wastewater Collection System				
	VOC	WCS monitoring program	• An effective monitoring program meeting the requirements of NSPS subpart QQQ standard applicable to individual drain systems. .	Recordkeeping and Reporting

BACT for Gas Fired Process Heaters

A new #2 Crude Unit Vacuum Heater (005HT0002) with a design heat input capacity of 26.2 MMBtu/hr (HHV) was installed in accordance with MAQP #1821-43 in October 2021. The #2 Crude Unit Vacuum Heater (005HT0002) is operating in accordance with the BACT limits which have been incorporated previously into MAQP #1821.

The RMUE includes the following actions related to #2 CU Main Heater (2CV-HTR-1 or 005HT001):

- Safety improvement to the burners.
- Metallurgy upgrades to the heater's heat transfer surfaces

The #2 CU Main Heater is fired with RFG and natural gas. As a result, it is a source of fuel combustion related emissions, including NO_X, PM, PM_{10}, $PM_{2.5}$, SO_2, CO, VOC, and H_2SO_4). Sulfuric acid mist (H_2SO_4) exists in the stack as an equilibrium byproduct due to the presence of SO_2. As a result, the proposed SO_2 BACT limit is considered a surrogate for H_2SO_4 emissions and no BACT analysis is provided for H_2SO_4.

Process Heater BACT Precedent Review

Available control technologies and BACT emission limits for NOx, $PM/PM_{10}/PM_{2.5}$, CO, and VOC from recently permitted gas fired process heaters were identified through a review of USEPA's RACT/BACT/LAER (RBLC) database, and recent PSD permit precedents.

The #2 CU Main Heater (005HT001) is a natural draft type heater with side fired induced draft burners that has a design heat input of 56.2 MMBtu/hr (HHV). Process heaters are used to raise the temperature of process fluids in radiant and convection tubes and operate at moderate fire box temperatures.

Process Heater NO_X BACT Analysis

Nitrogen oxides are formed as part of the combustion process and are generally classified in accordance with their formation mechanism as either thermal NO_X or fuel NO_X. Thermal NO_X is formed by the thermal dissociation and subsequent reaction of the nitrogen and oxygen in the combustion air at high temperature. The amount of thermal NO_X formation is a function of the combustion unit and burner design, flame temperature, residence time at flame temperature, and fuel/air ratios in the primary combustion zone. The rate of thermal NO_X formation increases exponentially with the flame temperature.

Fuel NO_X is formed by the gas-phase oxidation of the nitrogen that is chemically bound (*i.e.,* CN compounds) in the fuel (*i.e.,* char nitrogen). Fuel NO_X formation is largely independent of combustion temperature and the nature of the organic nitrogen compound. Its formation is dependent on fuel nitrogen content and the amount of excess combustion air (*i.e.,* the excess oxygen beyond the fuel's stoichiometric requirement). RFG and natural gas contain negligible amounts of fuel bound nitrogen. As such, the predominant type of NO_X that is formed in refinery process heater is thermal NO_X.

Control of the air/fuel stoichiometry is critical to achieving reductions in thermal NO_X. Thermal NO_X formation also decreases rapidly as the combustion temperature drops below the adiabatic flame temperature for a given stoichiometry. Maximum reduction of thermal NOx is achieved by simultaneous control of both combustion temperature and air/fuel stoichiometry.

Step 1: Identify All NO_X Control Technologies

Summary results from the NO_X BACT precedent review are presented in Table BACT-3. As shown, there are two fundamental categories of NO_X emission controls that are demonstrated for gas fired process heaters: low NOx burners (LNB) or ultra-low NO_X Burners (ULNB), and post- combustion catalytic control to selectively reduce NO_X emissions (referred to as selective catalytic reduction or SCR). In addition to the two categories listed above, an additional demonstrated control for gas fired boilers is the application of external flue gas recirculation (FGR).

Additional controls that are applied to the control of NO_X from other types of combustion sources include the following: selective noncatalytic reduction (SNCR), nonselective

Table BACT-3 Summary of NOx BACT Precedents for Gas Fired Conventional Process Heaters

RBLC ID No.	Facility Name	Permit Date	Process Description	Capacity (MMBtu/hr)	Control [a]	Emission Limit lb/MMBtu
MN-0093	Flint Hills Pine Bend Refinery	01/13/2017	Coker Heater	310	ULNB & SCR	0.01 365-day roll
AZ-0046	Arizona Clean Fuels	04/14/2005	8 Heaters	101 - 346	LNB & SCR	0.0125 3-hour average
LA-0211	Marathon Garyville Refinery	12/27/2006	4 Heaters	155 - 480	ULNB & SCR	0.0125 Annual average
TK-0847	Valero Port Arthur Refinery	09/16/2018	2 Heaters	248 - ?	ULNB & SCR	0.015 1-hour average
WY-0071	Sinclair Refinery	10/15/2012	BSI Heater	50	ULNB	0.025 3-hour average
MT 2619-32 [b]	Phillips 66 Company	01/15/2015	Vacuum Furnace H-17	75	ULNB	0.030 30-day roll
WY-0071	Sinclair Refinery	10/15/2012	Crude & Vacuum Heaters	64 - 233	ULNB	0.03 3-hour average
OH-0362	Lima Refining	12/23/2013	Crude Distillation Unit II Heater	624	ULNB	0.03 365-day roll
OK-0166, 0167 and 0170	Holly Tulsa Refinery West	2015	5 Heaters	76 - 248	ULNB	0.03 3-hour average
WY-0071	Sinclair Refinery	10/15/2012	2 Heaters	33 - 45	ULNB	0.035 3-hour average
LA-3444	Valero St. Charles Refinery	01/04/2018	CCR Heater	440	ULNB	0.04 3 one-hour tests
DE-0020	Valero Delaware City Refinery	02/26/2010	2 Heaters	240 - 456	ULNB	0.04 3-hour roll
LA-0283	Phillips 66 Alliance Refinery	08/14/2015	Low Sulfur Gasoline Feed Heater No. 1	168	ULNB & internal FGR	0.04 Annual average
LA-0314	Indorama Ventures Olefins, LLC	8/3/2016	Dryer Regenerator Heater	29	ULNB	0.06 3 1-hour tests

a- LNB- low NOx burners, ULNB- ultra low NOx burners, SCR- selective catalytic reduction.

b- Minor New Source Review Permit – State BACT.

catalytic reduction (NSCR), and EMx™. These controls, which are potentially applicable via technology transfer, are also considered.

NSPS subpart Ja NO_X standard at 40 CFR 60.102a(g)(2) is not applicable to the #2 CU Main Heater (005HT001). However, as noted, one of the project objectives is to make safety updates to the burners. This will be accomplished by replacing the existing burners with LNB technology. Because this heater has a tight firebox, John Zink, the burner manufacturer believes the achievable NO_X level will be limited to 0.05 lb/MMBtu. As a result, 0.05 lb/MMBtu is used as the baseline for this analysis.

Step 2: EliminateTechnically Infeasible NO_X Control Technologies

The following NO_X controls are considered demonstrated on gas fired refinery process heaters: LNBs/ULNB, and SCR. As a result, these controls are considered further by this analysis in Steps 3 through 5. The technical feasibility of external FGR (process heater), SNCR, NSCR, and EMx™ are evaluated further in Step 2 using the previously discussed criteria: applicability, availability, and demonstrated in practice.

<u>External Flue Gas Recirculation (FGR)</u>: FGR reduces thermal NO_X generation by reducing the concentration of oxygen in the burner flame region, and by providing more mass in the burner zone reducing overall combustion temperatures. There are two forms of FGR: external and internal. The NO_X control mechanism and the effect of FGR on performance for both forms, internal and external, are identical. The only difference between internal and external FGR is in the mechanics of introducing flue gas into the flame zone.

External FGR takes flue gases after heat recovery has been accomplished and recirculates a portion of the flue gas back to the burner combustion zone. To accomplish this, an external fan and ductwork is required to move the flue gas into the combustion zone. External FGR is primarily used for gas-fired boilers. Unlike petroleum refinery process heaters, which can have multiple small burners, gas fired boilers less than 500 MMBtu/hr heat input have few burners (one to four) that are co-located, and coupling the externally recirculated flue gas with the limited number of co-located burners is not difficult. As a result, external FGR has been widely applied to the control of NO_X from boilers and not process heaters. The use of external FGR is not considered technically feasible for the 24 side fired burners on the #2 CU Main Heater (005HT001).

Internal FGR is accomplished by recirculating the flue gases coming off the burner flame back into the base of the burner flame. Internal FGR is accomplished by the burner design. Burners using internal FGR are referred to as ultra LNB (ULNB). To better control the process tube skin temperatures and prevent coking of the process hydrocarbons in the tubes petroleum refinery process heaters have many small burners. As noted above, due to flame impingement concerns the achievable NOx level will be limited by the #2 CU Main Heater's firebox dimensions.

Selective Noncatalytic Reduction (SNCR): SNCR is a post-combustion NO_X control technology in which a selective reagent, either ammonia or urea, is injected into the exhaust gases to react with NO_X/NO_2, forming elemental nitrogen and water without the use of a catalyst. This process is effective in reducing NO_X/NO_2 emissions within specific constraints, requiring uniform mixing of the reagent into the flue gas within a zone of the exhaust path where the flue gas temperature is within a narrow temperature range of approximately 1600 to 2000°F. To achieve the necessary mixing and reaction, the residence time of the flue gas within this temperature window must be at least one half second. The consequences of operating outside the optimum temperature range are severe. Above the upper end of the temperature range the reagent will convert to NO_X/NO_2 and below the lower end of the temperature range the desired chemical reactions will not proceed and the injected reagent will be emitted as ammonia slip.

Because SNCR's ability to achieve NO_X reduction requires operation of the combustion source within specific ranges it has previously only been applied to the control of NO_X emissions from sources that operate within well-defined operating ranges and that do not rapidly vary across those ranges. Refinery process heaters operate across much wider ranges. SNCR has not been widely applied within the refinery industry and is not considered feasible for the #2 CU Main Heater (005HT001). As a result, SNCR is eliminated from further consideration.

Nonselective Catalytic Reduction (NSCR). NSCR is used to reduce NO_X emissions in the exhaust of automotive engines and stationary internal combustion engines. NSCR systems are comprised of three different catalyst types used in series. The first catalyst in the series is a reducing catalyst that is used to react unburned hydrocarbon in the exhaust with NO_X in the exhaust. Tuning the engine to run fuel rich creates the unburned hydrocarbon. The next catalyst in the series is an oxidizing catalyst that is used to oxidize the unburned fuel to CO and water and the final catalyst, also and oxidizing catalyst, is used to oxidize any remaining CO. NSCR has only been applied to engines because it is impractical to tune a fired combustion source such as a process heater to combust in a fuel rich manner. As a result, this control type is considered infeasible for the proposed application and removed from further review.

EMx™: The EMx™ system (formerly referred to as SCONOX™) is an add-on control device that simultaneously oxidizes CO to CO_2, VOCs to CO_2 and water, NO to NO_2 and then adsorbs the NO_2 onto the surface of a potassium carbonate coated catalyst. The EMx™ system does not require injection of a reactant, such as ammonia, as required by SCR and SNCR and operates most effectively at temperatures ranging from 300°F to 700°F. The overall chemical reaction between NO_2 and the potassium carbonate catalyst is as follows:

$2NO_2 + K_2CO_3 \rightarrow CO_2 + KNO_2 + KNO_3$

The catalyst has a finite capacity to react with NO_2. As a result, to maintain the required NO_X/NO_2 removal rate, the catalyst must be periodically regenerated. Regeneration is accomplished by passing a reducing gas containing a dilute concentration of hydrogen across the surface of the catalyst in the absence of oxygen. Hydrogen in the regeneration gas reacts with the nitrites and nitrates adsorbed on the catalyst surface to form water and molecular nitrogen.
Carbon dioxide in the regeneration gas reacts with the potassium nitrite and nitrates to form potassium carbonate, the original form of the chemical in the catalyst coating. The overall chemical reaction during regeneration is as follows:

$KNO_2 + KNO_3 + 4H_2 + CO_2 \rightarrow K_2CO_3 + 4H_2O + N_2$

The regeneration gas is produced in a gas generator using a two-stage process to produce molecular hydrogen and carbon dioxide. In the first stage, natural gas and air are reacted across a partial oxidation catalyst to form carbon monoxide and hydrogen. Steam is added to the mixture and then passed across a low temperature shift catalyst, forming carbon dioxide and more hydrogen. The regeneration gas mixture is diluted to less than four percent hydrogen using steam. To accomplish the periodic regeneration, the EMx™ system is constructed in numerous modules which operate in parallel so that one module can be isolated and regenerated while the remaining modules are lined up for treatment of the exhaust gas stream.

There are currently six EMx™ units in commercial installations worldwide. All are on natural gas-fired combustion turbines of 45 MW or less.[17] There are no known installations on process heater. There are a number of differences between the operation and flue gas characteristics of combustion turbines and the proposed new process heater. Specifically, combustion turbines are essentially constant flue gas flow combustion devices no matter what the load. Process heater gas flow rates are directly proportional to load. The impact on the load following ability of the EMx™ is unknown with respect to process heater. Additionally, the concentration of NO_X/NO_2 in the flue gases from process heaters is much higher than that of the combustion turbine flue gases. This is due to the high oxygen content of the combustion turbine flue gas (~15% O_2) relative to the process heaters flue gas (~3% O_2). The impact of the flue gas oxygen content and NO_X/NO_2 concentration on the EMx™ is unknown with respect to process heaters. Finally, the combustion turbines where EMx™ has been demonstrated have all been fired with natural gas. The proposed process heaters will be RFG fired and as a result the flue gas will contain SO_2, which is known to act as a poison to the EMx™ catalyst. It should be noted that the EMx™ vendor does provide a solution for SO_2 containing exhaust gases but this technology has not been demonstrated. Based on the above factors the use of EMx™ to control NO_X emissions from the proposed process heater is considered technically infeasible and this technology is eliminated from further consideration.

Step 3: Rank Remaining NO_X Control Technologies by Control Effectiveness

Based on the precedents presented in Table BACT-2 and the discussion above, the following control technologies are considered technically feasible for the control of NOX from the #2 CU Main Heater:

- LNB/ULNB and
- LNB/ULNB followed by SCR technology.

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[17] The heat input for a 45 MW combined cycle combustion turbine would be approximately 300 MMBtu/hr, assuming an efficiency of 50 percent.

As shown in Table BACT-3, the NO_X emission limits using ULNBs range from 0.025 to 0.064 lb/MMBtu for petroleum refinery process heaters. There are a number of factors that influence the NO_X emissions rate that is achievable at a particular process heater, as follows:

- The specific process application influences the design of the heater and may limit the style of burners that may retrofit into that application;
- Because heaters are tuned for a given fuel composition, refineries that have fuel gas compositions that vary significantly in their heat and/or hydrogen content are not able to operate stably or consistently at reduced NO_X levels; and
- Process heaters that are expected to operate in a wide operating range experience higher NO_X rates on both a lb/MMBtu and lb/hr basis when operating at reduced loads below the effective range of LNB internal FGR technology.

As noted above the #2 CU Main Heater (005HT001) is a side fired heater comprising 24 burners. To determine the NO_X level achievable through the application of ULNB technology in this application John Zink a manufacturer of ULNB was contacted. Based on that contact, it was determined that their LNB could be guaranteed to achieve 0.05 lb/MMBtu.

For the application of LNB/ULNB plus SCR to process heaters Table BACT-3 shows NOx emission limits ranging from 0.01 to 0.015 lb/MMBtu. The NOx BACT impacts for the modified process heater are addressed in the following subsection for the application of SCR.

Step 4: Evaluate Most Effective NOx Control Technologies and Document Results

This subsection documents the energy, environmental, and economic impacts associated with applying SCR to the proposed process heaters. A summary of the impacts analysis is presented in Table BACT-4. The costs presented were developed in accordance with USEPA's Air Pollution Control Cost Manual methodology for SCR.[18] Capital costs were escalated to 2024 dollars using the Chemical Engineering Plant Cost Index. Costs and emissions estimates are based on an SCR inlet NO_X emission rate of 0.05 lb/MMBtu for the process heaters (application of LNB) and an SCR NO_X emission rate of 0.01 lb/MMBtu (based on RBLC precedents), and full load operation for 8,760 hours per year.

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[18] EPA Air Pollution Control Cost Manual Sixth Edition, January 2002; EPA/452/B-02-001.

Economic Impacts

The capital costs associated with the installation of SCR systems on the #2 CU Main Heater is dependent upon the rated heat input of the heater. The capital cost of the SCR system includes the catalyst; catalyst housing, induced draft fan, ammonia storage system; and ammonia injection system. A retrofit difficulty factor was then applied to account for the additional cost associated with retrofitting the SCR on an existing process heater. A summary of the costs associated with the retrofit is presented in Table BACT-4 with detailed cost estimates from the application Appendix C. The annual operating and maintenance (O&M) costs associated with the SCR systems are $218,000 per year. The annual O&M costs include the cost of ammonia, catalyst replacement, operating personnel and maintenance. A catalyst life of three years is assumed. The total annual cost for the SCR system is $697,000 per year. The total annual costs include the capital recovery,[19] and O&M costs. The resulting cost effectiveness of the SCR systems applied to the #2 CU Main Heater is $70,900 per ton of NOx removed.

Table BACT-4 Summary of NOx BACT Cost Impacts for SCR Applied to Refinery Fuel Gas Fired Process Heater

PARAMETERS	**#2 CU Main Heater (005HT001)**
Heat Input (MMBtu/hr HHV)	
Environmental Impacts	
Tons per Year NOx Emissions w/o SCR:	12.3
Tons per Year NOx Emissions with SCR: [b]	2.5
Tons per Year NOx Reduction: [b]	9.8
Economic Impacts	
Total Capital Requirement, $:	5,076,000
Annual O&M Costs, $:	218,000
Capital Recovery Costs, $:	479,000
Total Annual Costs, $:	697,000
SCR NOx Reduction Cost Effectiveness, $/T:	**70,900**

a - Inlet NOx to the SCR is 0.05 lb/MMBtu.
b - NOx emissions with SCR based on 0.01 lb/MMBtu, 8760 hour per year at full load operation.

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[19] Standard USEPA capital recovery factor of 0.0944 based on 20 year control system life and 7 percent cost of money.

Environmental Impacts

The application of SCR to the proposed process heater will result in the emissions of ammonia and additional fine particulate matter in the form of ammonium salts. The emission of ammonia results from incomplete utilization of the ammonia injected before the SCR catalyst. This unreacted ammonia, referred to as ammonia slip, either is exhausted to the atmosphere as ammonia or combines with sulfur species in the flue gas to form ammonium salts.

The installation of an SCR system increases the pressure drop through the heater flue gas path requiring the installation of an induced draft fan. The induced draft fan electric power requirement and SCR system power requirements result in an increase in the emissions rate of criteria pollutants (NO_X, CO, PMs, etc.) where the power is generated.

The spent catalyst is comprised of metals that are not considered toxic. This allows the catalyst to be handled and disposed of following normal waste procedures.

Energy Impacts:

The energy impact of applying SCR to the #2 CU Main Heater comes from the power required to drive the induced draft fan and operate the ammonia injection and storage equipment.

Step 5: Select NOx BACT

The use of LNB technology is selected as BACT. Based on the adverse economic impacts, LNB plus SCR was not selected as BACT. The cost effectiveness of applying SCR technology to the #2 CU Main Heater is $70,900 per ton of NOx reduced. This cost is well above the range of cost effectiveness considered reasonable and acceptable in BACT determinations for control of NO_X emissions.

The following BACT limits are proposed:

- 2.81 lb/hour[20,21]
- USEPA reference method 7E will be used to demonstrate compliance with the proposed limit.

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[20] 0.05 lb NO_X/MMBtu (HHV) times 56.2 MMBtu/hr heat input.

[21] The proposed form of the limit (i.e., lb/hr is consistent with prior MDEQ heater limits issued for the CHS Laurel

The proposed BACT limits are based on the following:

- The configuration of the #2 CU Main Heater
- The variable hydrogen and Btu content of the CHS RFG and its resultant impact on stable NO_X emissions control, and
- The wide range of operating loads that the proposed units will be operated at and the inability of ULNB technology to sustain the same NOx rate at all load levels.

Process Heater PM BACT Analysis

Emissions of PM (*i.e.,* PM, PM_{10}, and $PM_{2.5}$) from gaseous fuel fired process heaters result from inert solids contained in the combustion air, unburned fuel hydrocarbons resulting from incomplete combustion that agglomerate to form particles, and condensable/secondary particulates formed as acid gases (e.g., conversion of sulfur containing compounds in the fuel to sulfur trioxide). The filterable PM emitted from the heater stack is expected to be less than 2.5 micrometers in aerodynamic particle size diameter, so the identified precedents for PM_{10} and $PM_{2.5}$ are assumed to be equivalent. As a result, the BACT analysis presented herein focuses on filterable and condensable particulate matter as measured by EPA Methods 5 and/or 201, and 202.

Step 1: Identify All PM_{10}/$PM_{2.5}$ Control Technologies

Table BACT-5 presents a summary of the RBLC database precedents for total PM_{10} emissions (*i.e.,* filterable plus condensable) from conventional refinery fuel gas fired process heaters. As shown, good combustion practices (GCP) and the use of clean or gaseous fuels are the only controls identified for PM from gas fired heaters. Emissions limits for these determinations ranged from 0.0069 to 0.0075 lb/MMBtu with the vast majority being 0.0075 lb/MMBtu[22].

The only methods used for controlling PM from gas fired heaters include the use of clean fuel, such as natural gas and RFG, and GCP. Add-on controls, such as ESP's, baghouses, and scrubbers, have never been applied in the broader context on gas fired combustion sources.

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[22] The AP-42 emission factor for total PM (filterable plus condensable) is 7.6 lb/10^6 scf (Table 1.4-2, 5th Edition, 1998). This is equivalent to 0.0075 lb/MMBtu for natural gas with a Btu content of 1020 Btu/scf.

Based on the BACT precedent information presented in Table BACT-5, and taking into account technology transfer from other combustion sources, the following PM emissions control technologies were identified as "available":

- Add-on control technologies including electrostatic precipitators, baghouses or fabric collectors, and venturi or packed bed scrubbers.
- Use of clean (*i.e.,* low ash) and low sulfur fuels such as natural gas; and
- Combustion controls and practices designed to minimize the production of soot.

Table BACT-5. Summary of PM_{10} BACT Precedent for Gas Fired Process Heater

RBLC ID NO.	Facility Name	Permit Date	Process Description	Capacity (MMBtu/hr)	Control	PM_{10} Limit lb/MMBtu	Test Method
OH-0357	BP-Husky Refining	09/20/2013	Coker 3 Furnace	247	Not specified	0.0069 Calculated from lb/hr	EPA/OAR 201A and 202
LA-0213	Valero St. Charles Refinery	11/17/2009	2 Heaters	68 & 90	GCP	0.0074	Not specified
OH-0357	BP-Husky Refining	09/20/2013	5 Heaters	23 - 247	Not specified	0.0075 (AP-42)	EPA/OAR 201A and 202
OH-0329	BP-Husky Refining	08/07/2009	Reformer Heater	519	No add on controls	0.0075 Calculated from lb/hr	OTM 27 & 28
MN-0093	Flint Hills Pine Bend Refinery	01/13/17	Coker Heater	310	GCP	0.0075, 3-hour roll	EPA Method 5 or 5B with Method 202
OK-0166	Holly Tulsa Refinery - West	04/20/15	2 Heaters	76 - 125	ULNB, gaseous fuel	0.0075, 3-hour average	Not specified
OK-0167	Holly Tulsa Refinery - East	04/20/15	2 Heaters	127 - 248	Gaseous fuel	0.0075	Not specified
TX-0847	Valero Port Arthur Refinery	09/16/2018	Heater	248	Fuel gas, GCP	0.0075	Not specified

GCP - Good combustion control, good burner technology, or proper design, operation, and good engineering practices.

Step 2: Eliminate Technically Infeasible PM/PM_{10}/$PM_{2.5}$ Control Technologies

As noted above, there are no known applications of add-on controls for PM emissions from heaters firing gaseous fuel. This is because PM emissions from the subject sources are inherently low because 1) gaseous fuels have no ash content that would contribute to the formation of filterable PM, and 2) the potential for soot formation is very low if GCPs are followed.

Add-on control technologies such as ESP's, baghouses, and scrubbers are considered technically infeasible for controlling PM emissions from the proposed gas fired. This is because these technologies have design outlet PM emissions that are typically higher than what gas fired heaters emit, and because the technologies would be ineffective in removing any additional PM because any filterable PM from gaseous fuel combustion is very fine and cannot be effectively captured. The remaining control methods identified, including fuel specifications and good combustion design/practices are considered technically feasible.

Step 3: Rank Remaining PM Control Technologies by Control Effectiveness

Technically feasible PM control technologies for the #2 CU Main Heater are ranked below in descending order of control effectiveness:

- Use of clean (i.*e.,* low ash), low sulfur fuels such as natural gas and RFG; and
- Combustion controls and practices designed to minimize the production of soot.

Steps 4 and 5: Evaluate Most Effective PM Control Technologies and Select BACT

The proposed BACT for PM emissions from the #2 CU Main Heater includes each of the technically feasible approaches presented above. Therefore, no further evaluation of control technologies is necessary.

CHS proposes the following total PM/PM_{10}/$PM_{2.5}$ BACT limits:

- Proper design and good combustion practices
- Compliance via recordkeeping per 40 CFR Subpart DDDDD.

These proposals are consistent with the RBLC review findings for conventional refinery fuel gas fired process heaters and the 2020 MUE preconstruction permit application (MAQP #1821-43) BACT determination for the #2 CU Vacuum Heater.

Process Heater SO_2 BACT

SO_2 emissions from process heater are a direct function of the sulfur content of the fuel that is burned. Reduced sulfur compounds in the fuel are readily oxidized to SO_2 and to a much lesser extent SO_3. The #2 CU Main Heater uses RFG or natural gas as the fuel.

Step 1: Identify All SO_2 Control Technologies

Emissions of SO_2 from process heaters can be controlled by fuel specifications or by using post-combustion controls. Fuel specifications limit SO_2 emissions by specifying a maximum allowable sulfur concentration in the gaseous fuels combusted in the process heater. Post- combustion control for SO_2 involves treating the combustion gases with an alkaline reagent that reacts with the SO_2 to produce a sulfur salt byproduct (e.g., sodium sulfite). This type of post- combustion control process is generally termed Flue Gas Desulfurization (FGD). FGD technology is well-established for sources with relatively high levels of sulfur emissions. It has not been applied to refinery process heaters, generally because fuel gas desulfurization is a more cost-effective means of reducing SO_2 emissions. Each of these control techniques is discussed further below.

Gaseous Fuel Specifications/Use of Natural Gas only. Pipeline quality natural gas has very low sulfur content, generally in the form of mercaptans (at about 4 ppmv) used for "odorization," and the gas may also contain trace quantities of reduced sulfur compounds (a few grains/100 scf). SO_2 emissions from natural gas-fired equipment are generally considered the lowest practically achievable for that fuel and do not require additional control equipment.

Gaseous Fuel Specifications/Use of Low-sulfur Refinery Gas. Refinery gas typically has higher sulfur content than the natural gas purchased from a pipeline. The RFG sulfur content is dependent on the removal efficiency of the fuel gas amine scrubbing units in a refinery. The #2 CU Main Heater will use RFG or natural gas as its fuel. To comply with the NSPS subpart Ja standard, CHS will use the existing amine scrubbing system to produce RFG with less than 60 ppmv H_2S, on an annual average basis. On a short-term basis, variability in the operation of the amine scrubbing system may result in spikes in the sulfur concentration of the sweet RFG produced (*i.e.,* as much as 162 ppmv sulfur on a 3-hour average basis).

Flue Gas Desulfurization. FGD is commonly used for control of SO_2 from solid fuel- combustion, such as coal or heavy oil-fired sources. FGD technologies are available and demonstrated in a variety of wet or dry scrubbing configurations. They have demonstrated control efficiencies of up to 95 percent on coal-fired combustion systems.

Step 2: Eliminate Technically Infeasible SO_2 Controls

FGD technology is not commercially demonstrated on refinery process heaters because it is not cost effective compared to desulfurizing the fuel gas with the use of an amine scrubbing system. In addition, removing the sulfur from the fuel rather than the exhaust gas allows much lower SO_2 levels in the exhaust to be achieved. The use of FGD technology would also require the design of the process heater to be significantly altered (*i.e.,* to a mechanical draft design) to provide the flue gas pressure required for adding an FGD system. As a result, FGD technology is removed from consideration.

Step 3: Rank Remaining SO_2 Control Technologies by Control Effectiveness

The top performing feasible SO_2 control technology is the firing of 100% purchased natural gas in the heater, because of the very low sulfur content of natural gas. The next most effective control technology is the use of refinery fuel gas treated to sulfur levels that meet the NSPS Subpart Ja standards. This is the baseline for SO_2 emissions from the #2 CU Main Heater.

Step 4: Evaluate Most Effective SO_2 Controls and Document Results

Table BACT-6 presents the cost and cost effectiveness of firing natural gas vs. refinery fuel gas in the proposed heater. For the natural gas firing scenario, the table shows a cost effectiveness of $0.8 million/ton SO_2 reduced, based on a natural gas price of $3/MMBtu. As such, this option is not considered cost effective, and is rejected as BACT.

Table BACT-6. Results of Process Heater SO_2 Control Cost Analyses

Control Alternative	SO_2 Emissions (TPY)	SO_2 Emissions Reduction (TPY)	Total Annualized Cost ($10⁶/yr)[b]	Average Cost Effectiveness ($10⁶/ton SO_2 controlled)	Environ. Impacts (Yes/No)	Energy Impacts (Yes/No)
Natural gas firing	0.15[a]	1.76	1.48	0.8	No	Yes
Refinery gas firing (baseline)	1.91	---	---	---	---	---

[a] 0.15 TPY = 56.2 MMBtu/hr * 0.0006 lb SO_2/MMBtu (AP-42) * 24 hr/day * 365 day/yr * 1T/2000 lb

[b] $1.48 million/yr = [56.2 MMBtu/hr (HHV)] x (8,760 hr/yr) x ($3.00/MMBtu N.G.) / (1 million)

Step 5: Select SO_2 BACT

The emission estimates for SO_2 from the heater are based on the following proposed SO_2 BACT:

- Refinery fuel gas H_2S content of 60 ppmv (365-day rolling average);
- Refinery fuel gas H_2S content of 162 ppmv (3-hr roll); and
- Compliance shall be demonstrated in accordance with 40 CFR 60.107a(a).

Process Heater CO BACT

Carbon monoxide (CO) is a product of incomplete combustion. The formation of this pollutant is limited by ensuring complete and efficient combustion of the fuel in the heater. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Measures taken to minimize the formation of NO_X during combustion may inhibit complete combustion, which can increase CO emissions. Lowering combustion temperatures through staged combustion to reduce NO_X emissions can be counterproductive with regard to the production of CO emissions. However, the improved air/fuel mixing that is inherent in newer ULNB designs and control systems helps to overcome the impact of fuel and/or air staging on CO emissions. This section presents the CO BACT analysis for the proposed process heater.

Steps 1: Identify CO Control Technologies

Based on a review of the information provided in the RBLC database, summarized in Table BACT-7 for the conventional process heaters, good combustion practices (GCP) is the only CO control identified. One additional control that is applied to the control of CO from other types of combustion sources is CO oxidation catalyst. This control, which is potentially applicable via technology transfer, is also considered.

Good combustion practice (GCP) incorporates the following practices:

- Good combustion,
- Heater/burner proper design and operation, and
- Use of ULNB technologies.

As with other types of fossil fuel-fired systems, combustion control is the most effective means for reducing CO emissions from gas fired process heaters. Good combustion is a function of the three "T's" of combustion: Temperature, Turbulence, and Time where:

- Temperature is high enough to ignite the fuel,
- Turbulence is vigorous enough for the fuel constituents to be exposed to the oxygen, and Time is long enough to assure complete combustion.

These components of combustion efficiency are designed into the heaters and burners to maximize fuel efficiency and reduce operating costs. Therefore, combustion control is accomplished primarily through heater/burner design and operation. The use of good combustion practices is considered technically feasible and considered further by this analysis.

Table BACT-7. Summary of CO BACT Precedents for Gas Fired Process Heater

RBLC ID No.	Facility Name	Permit Date	Process Description	Capacity (MMBtu/hr)	Control	Emission Limit lb/MMBtu
MS-0089	Chevron Pascagoula Refinery	04/14/09	5 Heaters	51 - 74	LNB/ULNB	0.032 30-day Basis: 50 ppm @ 0% O_2
MS-0086	Chevron Pascagoula Refinery	05/08/07	2 Heaters	160 & 850	ULNB	0.037 12-month Basis: 50 ppm @ 3% O_2
TX-0539	Total Refining - Port Arthur	07/22/09	4 Heaters	42 - 211	GCP	0.037 hourly Basis: 50 ppm @ 3% O_2
WY-0071	Sinclair Refinery	10/15/12	6 Heaters	45 - 233	ULNB & GCP	0.04 3-hour ave.
OH-0362	Lima Refining Company	12/23/13	2 Heaters	102 - 624	GCP	0.04, 365-day roll
OK-0166, 0167, 0170	Holly Tulsa Refinery – East and West	2015	5 Heaters	76 - 248	ULNB	0.04, 3-hour average
OH-0357	BP-Husky Refining LLC	09/20/13	4 Heaters	150 - 247		0.06
PA-0299	Philadelphia Energy Solutions	02/19/14	7 Heaters	60 - 254		0.0824, 3 one-hr tests

LNB- low NOx burners, ULNB- ultra low NOx burners, GCP- good combustion control, or good burner technology, or proper design, operation, and good engineering practices.

Oxidation Catalyst has been applied to the control of CO from natural gas-fired combined cycle gas turbines and to a limited extent on boilers. Oxidation catalyst is typically a precious metal catalyst (e.g., platinum), which has been applied over a metal or ceramic substrate. The catalyst lowers the activation energy required for the oxidation of CO so that CO is oxidized at temperatures between 400°F and 1,100°F. No chemical reagent addition is required.

Oxidation catalyst technology has been applied at several natural gas-fired boilers and many combustion turbines. Thus, it is considered technically feasible for application on combustion turbines and boilers firing low sulfur fuels. However, in the case of refinery process heaters, use of oxidation catalyst technology is not technically feasible due to leaks that may occur in heater tubes. Although tube leaks are common in boilers and combustion turbine heat recovery steam generators, the fluid leaked is steam or water. Water is not combustible and therefore it passes through the oxidation catalyst without harming the catalyst. In contrast, when a tube leaks in a process heater, hydrocarbons leak into the furnace and end up in the combustion flue gas. The leaked hydrocarbon gases in the combustion flue gas will be oxidized by the catalyst and if present in sufficient concentration, will release enough heat to damage the oxidation catalyst as well as the heater.

Additionally, combustion turbines and boilers currently equipped with oxidation catalyst are natural gas fired. Natural gas has very low levels of sulfur compounds. Oxidation catalyst oxidizes a significant portion of the sulfur compounds in the fuel to sulfur trioxide which then combines with water to form sulfuric acid mist. This is not a significant issue when firing natural gas. Refinery gas contains significantly more sulfur compounds than natural gas, and as such, the use of oxidation catalyst on RFG fired boilers would result in the formation of a significant amount of sulfuric acid mist in the flue gas. The sulfuric acid mist would corrode the backend of the heater and increase the emissions of $PM_{10}/PM_{2.5}$ to the atmosphere.

CHS is not aware of any RFG fired heaters that have been equipped with oxidation catalyst. For the above reasons, the use of oxidation catalyst is considered technically infeasible and not considered further. Only good combustion design and operation is considered to be technically feasible for the control of CO from the proposed heater.

Step 2: Eliminate Technically Infeasible Options.

Since the RBLC had a single identified control of good combustion practices, there are no control technologies to eliminate.

Steps 3-5: Establish Hierarchy and Process Heater CO BACT Limit

The only technically feasible control option for CO emissions from process heater is good combustion design and operating practices. Therefore, the remainder of this analysis focuses on the achievable emission rates/limits for conventional petroleum refining process heaters.

Table BACT-7 summarize the results from the review of past petroleum refinery process heater precedents identified from the RBLC database. As shown, permit limits range from 0.02 lb/MMBtu to 0.0824 lb/MMBtu. The majority of the determinations range from 0.037 to 0.04 lb/MMBtu.

Based on a CO emissions rate of 0.04 lb/MMBtu, CHS proposes the following CO BACT emissions limits:

- #2 CU Main Heater (005HT001): 2.25 lb/hour,[23]
- USEPA reference method 10 will be used to demonstrate compliance with the proposed limit.

These limits are consistent with the most recent BACT determinations for similar size refinery process heaters.

Process Heater VOC Control Analysis

Volatile organic compounds (VOC) are products of incomplete combustion. The formation of these pollutants is limited by ensuring complete and efficient combustion of the fuel in the heater. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimizes VOC emissions. Measures taken to minimize the formation of NO_X during combustion may inhibit complete combustion, which can increase VOC emissions.

Lowering combustion temperatures through staged combustion to reduce NO_X emissions can be counterproductive with regard to VOC emissions. However, the improved air/fuel mixing that is inherent in newer ULNB designs and control systems help overcome the impact of fuel and/or air staging on VOC emissions. This section presents the VOC BACT analysis for the #2 CU Mian

Heater.

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[23] 0.04 lb NOx/MMBtu times 56.2 MMBtu/hr heat input.

Step 1: Identify all VOC Control Technologies

Based on a review of the information provided in the RBLC database, summarized in Table BACT-8, and knowledge related to the control of VOC emissions from combustion sources, the following controls were identified:

- Oxidation catalyst, and
- Good combustion practices. [24]

Steps 2: Eliminate Technically Infeasible VOC Options

Oxidation catalysts have previously been applied to natural gas fired combustion turbines and to a limited extent natural gas fired boilers located in CO and/or ozone nonattainment areas. The catalyst lowers the activation energy for the oxidation of VOC so that it is oxidized at lower temperatures (600 to 1100°F). The removal efficiency for VOC is typically in the range of 50 to 60 percent, depending on the flue gas temperature and the VOC characteristics. Oxidation catalyst technology has been applied at several natural gas-fired boilers and many combustion turbines. As a result, it is considered technically feasible for application on combustion turbines and boilers firing low sulfur fuels (natural gas).

However, in the case of refinery heaters, use of oxidation catalyst technology is not technically feasible due to leaks that may occur in heater tubes. Although tube leaks are common in boilers and combustion turbine heat recovery steam generators, the fluid leaked is steam or water.
Water is not combustible and therefore it passes through the oxidation catalyst without harming the catalyst. In contrast, when a tube leaks in a process heater, hydrocarbons leak into the furnace and end up in the combustion flue gas. The leaked hydrocarbon gases in the combustion flue gas will be oxidized by the catalyst and if present in sufficient concentration, will release enough heat to damage the oxidation catalyst as well as the heater.

Additionally, combustion turbines and boilers equipped with oxidation catalyst are natural gas fired. Natural gas has very low levels of sulfur compounds. Oxidation catalyst oxidizes a significant portion of the sulfur compounds in the fuel to sulfur trioxide (SO_3), which then combines with water to form sulfuric acid mist. This is not a significant issue when firing natural gas. Refinery gas contains significantly more sulfur compounds than natural gas, and as

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[24] Also referred to as good combustion control, and good equipment design and proper combustion.

Table BACT-8. Summary of VOC BACT Precedent for Gas Fired Process Heater

RBLC ID No.	Facility Name	Permit Date	Process Description	Capacity (MMBtu/hr)	Control	Emission Limit lb/MMBtu
LA-0211	Marathon Garyville Refinery	12/27/06	5 Heaters	76 - 474	GCP	0.0015 3-hour average
IL-0103	ConocoPhillips Wood River Refinery	08/05/08	New & Modified Heaters (7 New, 1 Modified)	20 - 1275	GCP	0.003 3-hour average. (LAER determination)
TX-0478	Citgo Corpus Christi Refinery	04/20/05	Mixed Distillate Hydroheater	20	LNB	0.0053 (Basis: lb/hr)
OH-0357	BP-Husky Refining LLC	09/20/13	3 Heaters	150 - 225	Gas Fuel Part 63 Subpart DDDDD	0.0054
LA-0197	ConocoPhillips Alliance Refinery	07/21/09	Low Sulfur Gasoline Feed Heater No. 1	138	GCP	0.0054 (Basis: lb/hr)
AL-0242	Hunt Refining Tuscaloosa Refinery	05/20/08	Eight (8) Process Heaters	35 - 254	GCP	0.0054
LA-0213	Valero Refining St. Charles Refinery	11/17/09	CPF Heater H-39-03 & Amp; H-39-02 (94-28 &Amp; 94-30)	68 & 90	GCP & GASEOUS FUELS	0.0054
OK-0102	ConocoPhillips Ponca City Refinery	08/18/04	Process Heaters & Boilers	12 to 241	GCP	0.0054
TX-0877	Phillips 66 Sweeny Refinery	01/08/20	Process Heater		GCP	0.0054
TX-0847	Valero Port Arthur Refinery	09/16/18	Process Heater	248	GCP	0.0054

LNB- low NOx burners, ULNB- ultra low NOx burners, GCP- good combustion practices or control. Includes good burner control or burner technology; or proper design, operation, and good engineering practices, LAER- lowest achievable emission rate.

such the use of oxidation catalyst on RFG fired boilers would result in the formation of a significant amount of sulfuric acid mist. The sulfuric acid mist would corrode the backend of the boiler and increase the emissions of $PM_{10}/PM_{2.5}$ to the atmosphere.

CHS is not aware of any RFG fired heaters that have been equipped with oxidation catalyst. For the above reason, the use of oxidation catalyst is considered technically infeasible and not considered further by this analysis.

Good combustion practices, as the name infers, are based upon maintaining good fuel/air mixing, a proper fuel/air ratio, and adequate time at the required combustion temperature. As with other types of fossil fuel-fired systems, combustion control is the most effective means for reducing VOC emissions from gas fired process heaters. Good combustion is a function of the three "T's" of combustion: Temperature, Turbulence, and Time where:

- Temperature is high enough to ignite the fuel,
- Turbulence is vigorous enough for the fuel constituents to be exposed to the oxygen, and
- Time is long enough to assure complete combustion.

These components of combustion efficiency are designed into the heaters and burners to maximize fuel efficiency and reduce operating costs. Therefore, combustion control is accomplished primarily through heater/burner design and operation. The use of good combustion practices is considered technically feasible and considered further by this analysis.

Steps 3-5: Establish Hierarchy and Process Heater VOC BACT Limit

The only technically feasible control option for VOC emissions from a process heater is good combustion design and operating practices. Therefore, the remainder of this analysis focuses on the achievable emission rates/limits for conventional petroleum refining process heaters.

As shown in Table BACT-8 precedents for a gas fired process heater range from 0.0015 lb/MMBtu to 0.0054 lb/MMBtu. The majority of the VOC determinations range from 0.005 to 0.0054 lb/MMBtu.

CHS proposes the following VOC BACT limits for the #2 CU Main Heater:

- Proper design and good combustion practices.
- Compliance via recordkeeping per 40 CFR Subpart DDDDD.

These limits are consistent with the most recent BACT determination for similar size refinery process heaters (OH-0357), the majority of the RBLC determinations and the 2020 MUE preconstruction permit application (MAQP #1821-43) BACT determination for the #2 CU Vacuum Heater

Zone A and Zone D Sulfur Recovery Plant SO_2 BACT

As described in the application, as part of the 2024 RMUE modifications will be made in the Zone A and Zone D SRPs. SRPs are a source of sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter ($PM/PM_{10}/PM_{2.5}$), carbon monoxide (CO), volatile organic compounds (VOC), and sulfuric acid mist (SAM). The SO_2 emissions are a byproduct of the sulfur recovery process which results in trace amounts of reduced sulfur compounds that are oxidized in the TGI, and oxidation of sulfur in the supplemental fuel used to operate the TGI. The NO_X, $PM/PM_{10}/PM_{2.5}$, CO, and VOC emissions are produced in the TGI by the combustion of the supplement fuel. The SAM is formed as an equilibrium compound with the SO_2 that is emitted. A summary of the proposed BACT limits for the Zone A and Zone D SRPs is presented in Table BACT-9. BACT analyses are not provided for NO_X, $PM/PM_{10}/PM_{2.5}$, CO, and VOC emissions because these pollutants are produced by the existing and non-modified TGI which is a pollution control device operated to ensure that reduced sulfur compounds are not emitted. A BACT analysis is not provided for the SAM emissions because these emissions are the result of the thermodynamic equilibrium with SO_2. As a result, the SO_2 BACT limits are considered surrogate for SAM BACT limits.

Table BACT-9. Summary of Proposed BACT Controls and Limits for the Sulfur Recovery Plant

Emissions Unit	Pollutant	Control Technology	Limit/Averaging Time	Compliance Method
Zone A and Zone D SRPs				
	SO_2 and H_2SO_4 (SAM)	Tail Gas Treatment Unit with Incinerator	• 250 ppmvd SO_2, rolling 12-hour average corrected to 0% oxygen, applicable at all times except startup, shutdown, and malfunction (*i.e.,* NSPS subpart Ja standard) • Minimize the frequency and duration of startups and shutdowns of the Zone A SRP by operating at all times in accordance with an operation, maintenance and monitoring plan meeting the requirements of 40 CFR 63.1574(f). • Comply with 40 CFR 63 subpart UUU (Refinery MACT II) operating limits at 63.1568(a)(4) during periods of startup and shutdown.	• SO_2 Continuous Emissions Monitoring System (CEMS) operated in compliance with 40 CFR 60.106a

Sulfur Recovery Plant Process Overview

As previously presented, each of the refinery's SRPs (*i.e.,* the Zone A, Zone D, and Zone E SRPs) comprises the three process steps: Sulfur Recovery Unit (SRU), Tail Gas Treatment Unit (TGTU) and Tail Gas Incinerator (TGI).

During the combustion step, which takes place in the SRU's thermal reactor, hydrocarbons contained in the acid gas are also combusted. The combusted hydrocarbons and carbon dioxide react with sulfur to form carbon-sulfur compounds: COS and CS_2. The amount of COS and CS_2 that are formed is directly related to how tightly the air-to-fuel ratio can be controlled in the thermal reactor. Sudden changes in rate and composition of the acid gas stream being fed to the SRU (*i.e.,* the thermal reactor) affect the ability to control the air to fuel ratio. As noted below, these compounds are not as easily converted back to H_2S in the TGTU and are not absorbed by the amine used to capture H_2S in the TGTU and recycle it back to the front of the SRU. As a result, the COS and CS_2 are oxidized in the TGI and emitted as SO_2.

The primary keys to lower SO_2 emissions from the SRP are maintaining the ideal acid gas to combustion air ratio in the SRU, the recovery of H_2S in the TGTU, and the minimization of COS and CS_2 as part of the sulfur recovery process. Control of the acid gas to combustion air ratio is dependent on the flow and composition of the acid gas feed. The H_2S recovery is defined by the ability of the amine to remove H_2S in the TGTU and recycle it back to the front of the SRU. The COS and CS_2 concentrations exiting the process are defined by the ability to precisely control the reaction stoichiometry in the thermal reactor, catalyst type in the primary catalytic reactor, and TGTU hydrogenation reactor, reactor bed temperature, catalyst age, and presence of hydrocarbon and other contaminants in the SRU and TGTU feed streams. Thus, the amount of SO_2 in the incinerator stack can vary greatly, and as a result, the control of COS and CS_2 exiting the SRU is important to achieving a low SO_2 emission rates.

In addition to the SO_2 emissions resulting from the normal operation of the SRP described above, SO_2 emissions also result during the periodic startup and shutdown processes. A planned shutdown and subsequent startup can occur for a number of reasons including required maintenance or catalyst replacement. The SRP is also shut down when, due to maintenance shutdowns at acid gas generating units, there is not adequate acid gas feed to keep it in operation. An unplanned shutdown of an SRU and/or TGTU can be caused by a malfunction or other upset event in the SRP or refinery process area. Detailed operating procedures have been developed and are followed to ensure the startup and shutdown process is safe, prevents equipment and catalyst damage, and minimizes SO_2 emissions to the extent possible. During the multiple day startup and shutdown processes, the SO_2 concentration from the SRP is an order of magnitude higher than the SO_2 concentration during normal operation (*i.e.,* 3000 ppm vs. <250 ppm).

Step 1 Identify All SO_2 Control Options

Potentially available control technologies were identified through a review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, existing permits and permit applications, and other publicly available information sources. The objective of the analysis was to determine which of the identified technologies were potentially applicable to the Zone A and Zone D SRPs. For purposes of this analysis, only changes that could be made to the existing SRP (*i.e.,* modifications and retrofits) and add-on control technologies that could be used to further control the SO_2 emissions in incinerator exhaust were considered. A commonsense approach was used that eliminated any technologies that required the replacement of the existing SRU or TGTU or modification of the upstream refinery operation or processes that would require the unnecessary replacement of functioning equipment.

The following control technologies were identified as control options for the existing Zone A and Zone D SRPs:

- Multistage Claus trains followed by a tail gas treatment unit (TGTU).
- Multistage Claus trains followed by a TGTU which is then followed by wet gas scrubber (WGS) technology.

Step 2: Eliminate Technically Infeasible SO_2 Control Options

It should be noted that a large number of proprietary adaptations of the Claus reactor technology exist. For the purposes of this BACT analysis, these are not considered alternatives to the proposed configuration, but are considered as falling within the general technology description provided above. The capabilities attributed to the proposed equipment configuration take into account the performance levels that are achievable with these proprietary adaptations. One of the most widespread adaptations is the use of proprietary catalysts in the Claus catalytic reactors, without modifying the reactor configuration, to increase hydrolysis of COS and CS_2 to H_2S, which then participates in the Claus reaction for an improvement in the overall sulfur recovery efficiency.

Several of the proprietary adaptations operate by extending the Claus reaction to improve the thermodynamically achievable sulfur conversion efficiency, allowing the modified Claus reactor train to achieve compliance with most regulatory emission standards without the need for a tail gas treatment unit. One example of these proprietary adaptations is the Superclaus® process, which is a conventional Claus process, with a proprietary catalyst replacing the conventional, activated alumina Claus catalyst in the final catalytic reactor stage. The proprietary catalyst in the Superclaus® process selectively oxidizes H_2S to form elemental sulfur and water according to the following equation:

$2\ H_2S + O_2 \rightleftharpoons 2\ S + 2\ H_2O$

The Superclaus® process reportedly increases the thermodynamically achievable sulfur recovery efficiency to approximately 99.4 percent, as compared to an achievable efficiency less than 98 percent with the conventional Claus process.

Another example is the Euroclaus® process, which is an enhancement of the Superclaus® process, with a hydrogenation reactor inserted upstream of the final catalytic reactor stage. This hydrogenation reactor reduces the SO_2 concentration in the final reactor stage, which reportedly increases the thermodynamically achievable sulfur recovery efficiency to approximately 99.7 percent. One of the Zone A SRU trains and the Zone D SRU already include a third stage catalytic reactor and although this option is technically feasible to apply it would require a major redesign of each SRU and TGTU and result in only a marginal improvement in the overall recovery conversion (*i.e.,* the Zone A and Zone D SRPs currently achieves a conversion greater than 99%).

The Sulfreen® process is an example of a proprietary adaptation that utilizes a conventional Claus process, with an additional Claus-type reactor after the final sulfur condenser. This additional reactor operates at a temperature below the sulfur dew point and adsorbs the sulfur on

the Claus catalyst. Each of the two beds in the additional reactor is cycled between adsorption and regeneration; during the regeneration cycle, the hot gases are produced in an integral heater and, after desorbing the sulfur from the catalyst, are passed through an integral condenser.
Operation of the additional reactor at a sub-dew point temperature reportedly improves the thermodynamically achievable sulfur recovery efficiency to approximately 99 percent.
Variations on the Sulfreen® process include HydroSulfreen®, which includes a hydrogenation/hydrolysis reactor upstream of the Sulfreen® reactor, and DoxoSulfreen®, which includes all components of the HydroSulfreen® process, plus a direct oxidation reactor downstream of the Sulfreen® reactor. HydroSulfreen® and DoxoSulfreen® reportedly improve the achievable sulfur recovery efficiency to approximately 99.7 percent and 99.9 percent, respectively. One of the Zone A and the Zone D SRU already include a third stage catalytic reactor and although this option is technically feasible to apply it would require a major redesign of the existing SRU and TGTU and result in only a marginal improvement in the overall recovery conversion (*i.e.,* the Zone A and Zone D SRPs currently achieve a conversion greater than 99%).

Stretford, Z-SORB, LO-CAT®, and CrystaSulf® are proprietary liquid-phase oxidation-reduction technologies providing indirect oxidation of H_2S to form elemental sulfur and water. The Stretford process uses a vanadium-based chelating agent, the Z-SORB process uses a zinc-based chelating agent, and the LO-CAT® and CrystaSulf® technologies use proprietary, iron-based chelating agents. When installed in conjunction with an upstream Claus reactor train and hydrogenation/hydrolysis reactor, each of these technologies reportedly is capable of achieving a sulfur recovery efficiency in excess of 99.9 percent.

SulFerox is a redox-based technology that uses a concentrated iron solution to remove H_2S from gas streams and convert it to sulfur. Existing refinery applications have been limited to fuel gas clean up with no sour water stripper off gas applications identified. The refinery has existing equipment that is used to remove H_2S from the fuel gas system as well as treat sour water.
Additionally, the existing SRU's Claus units already recover 90 plus percent of the sulfur. Replacement of the entire existing SRUs and refinery acid gas removal are not within the scope of the BACT analysis. As such, this technology was removed from consideration.

Wet scrubbing is another control option, separate and distinct from the current equipment configuration of the Zone A and Zone D SRUs. Two examples of demonstrated, proprietary wet scrubbing technologies for sulfur recovery plants are the Wellman-Lord and Clintox® processes. The wet scrubbing control option would require an upstream combustion device to convert reduced sulfur compounds to SO_2 and could be used either with or without a Claus reactor train upstream of the combustion device. When used in conjunction with an upstream Claus reactor train, these technologies allow the SO_2 to be stripped from the solvent and returned to the front end of the Claus reactor train. In this configuration, each of these technologies reportedly is capable of achieving a sulfur recovery efficiency in excess of 99.9 percent. This technology could be applied by removing the existing TGTU, which is considered technically infeasible, or adding it to the exhaust of the existing SRP incinerator to achieve a small incremental reduction from the currently permitted levels.

Marsulex is a proprietary technology based on the use of regenerable caustic wet gas scrubber (WGS) technology. This technology produces sodium bisulfite as a by-product, which has some marketability. Application of this technology requires that the exhaust of the Claus plant be incinerated to convert all reduced sulfur compounds to SO_2 prior to scrubbing. There two operating petroleum refining applications, one in Canada and one in Indiana. This technology could be applied by removing the existing TGTU, which is considered technically infeasible, or adding it to the exhaust of the existing SRP incinerator to achieve a small incremental reduction from the currently permitted levels. The latter option would likely be economically infeasible.

The Shell Claus Offgas Treating ("SCOT") process is the most commonly used process for removal of sulfur from Claus SRU vent streams and is currently installed in both Zone A and Zone D SRPs. As described above, an MDEA-based solvent is generally used in the amine absorber columns within the tail gas treater. As with the Claus reactor train, there exist numerous proprietary adaptations on the SCOT process, generally involving the use of proprietary solvents. For the purposes of this BACT analysis, these are not considered alternatives to the proposed configuration, but are considered as falling within the general technology description already provided. The capabilities attributed to the proposed equipment configuration take into account the performance levels that are achievable with these proprietary adaptations. Available proprietary solvents for use in tail gas treating include as Sulften®, Flexsorb® SE, or Flexsorb® SE Plus, in place of the general MDEA solvent.

Step 3: Rank Remaining SO_2 Control Technologies by Control Effectiveness

The next step in the analysis is to determine the achievable emissions rate associated with the technically feasible options. This information is used to rank the alternatives in a top-down hierarchy (*i.e.,* from most to least stringent). In some cases, due to the case-by-case nature of BACT, there may be multiple control levels identified for the same technology. In those cases, the most stringent control level is evaluated first. If it is eliminated due to environmental, energy, or cost impacts, then the next most stringent control level is evaluated. The least stringent alternative that can be selected as BACT is the applicable NSPS standard. Since the Zone A and Zone D SRPs are subject to the NSPS subpart J/Ja SO_2 standard found at 40 CFR 60.104 and 40 CFR 60.102a (*i.e.,* 250 ppm by volume (dry basis) SO_2 at 0% excess air on a rolling 12-hour basis), this is the least stringent level that can be proposed.

To determine the hierarchy of precedents for the feasible controls, available information sources including the RBLC and other permits/permit applications were reviewed. One result of the review was the discovery that the form of the BACT limits vary among the identified precedents. Because the applicable NSPS standard and the recently revised CHS Laurel refinery Zone D SRP BACT limits (MAQP #1821-40) are concentration based, the precedents that were not concentration based were eliminated from consideration. As such, only concentration-based limits are considered further by this analysis.

A summary of the information obtained from the review of the RBLC and other information sources that have concentration-based limits is presented in Table BACT-10. The precedents are presented from most to least stringent.

Table BACT-10. Summary of SO_2 BACT Precedents for Sulfur Recovery Plants

RBLC ID No.	Facility Name	Permit Date	Process Description	Capacity (LTD)	SO_2 Limit
CA	Chevron El Segundo Refinery		SRU + TGTU + WGS		12 ppmvd 72-hr avg.
LA- 0355	Marathon Garyville Refinery	9/6/2018	SRU + TGTU		75 ppmv annual avg.
TN	Williams Refining		SRU + TGTU		75 ppmv annual avg. 150 ppmvd 24-hr avg.
TX- 0847	Valero Port Arthur Refinery	9/16/2018	SRU + TGTU	417	250 ppmvd 1-hr avg. 97 ppmvd 24-hr avg. 100 ppmvd annual avg.
IN-0317	Riverview Energy Corporation	6/11/2019	SRU + TGTU (EU 3001 & EU-3002)	159 combined	26.30 lb/hr (ea.) 167 ppmv 12-hour avg. 150 ppmv 12-mth avg.
	CHS Laurel Refinery – Zone D	7/25/2018	SRU + TGTU		250 ppmv, 12-hr avg.
	CHS Laurel Refinery – Zone A	12/19/2005	SRU + TGTU		200 ppmv, 12-mtn avg.

As noted in Table BACT-9, with this application CHS is not proposing 12-month average SO_2 concentration-based BACT limits. CHS' experience with the current long-term, concentration- based rolling 12-month limit, which is interpreted as being applicable during periods of normal operation, is that it does not account for the impact of short duration upsets when the concentration of SO_2 in the incinerator exhaust is unusually high (*i.e.,* several thousand ppm vs. typical SO_2 concentration of less than 200 ppm and 250 ppm for the Zone A and Zone D SRP, respectively). These short-term, high concentration events impact the long-term rolling 12-month average over an extended period. As an example, the SO_2 concentration at the Zone A SRP has recently averaged approximately 135 ppm. During an upset, to avoid a complete shutdown of the SRP, the SRP may need to operate without the TGTU. During that recovery period, the SO_2 concentration will increase to between 2,000 ppm and 14,000 ppm. In this example, operating without the TGTU for two days would result in an increase of the 12-month rolling average concentration by approximately 158 ppm and 930 ppm, respectively, and that single event would be reflected in the average for twelve months although the duration of the event was two days. This type of step-change in the long-term rolling average SO_2 concentration is not reflective of the actual performance of the SRP over the extended time period. Based on this impact and the fact that the NSPS is also in the form of a short-term concentration-based limit, CHS has concluded that a short-term BACT limit that is applicable during normal operation is the most appropriate form for an SRP SO_2 BACT limit. Additionally, setting the BACT limit based on a rolling 12-hour average would match the limits previously established for the Zone

D SRP with the same rolling 12-hour average. Annual SO_2 limits were previously established in MAQP #1821-13 (Delayed Coker Project) for the Zone A SRP and these limits remain in effect as they were PSD avoidance limits by keeping the Delayed Coker Project SO_2 increases below 40 tpy. The annual SO_2 limit for Zone A is in Section IX.E.1. DEQ has not removed the 200 ppm, rolling 12-month average in this permitting action, however DEQ has corrected the previous ARM 17.8.752 reference to ARM 17.8.749, as the previous limits were not intended to be incorporated as BACT limits. The limits were established as PSD avoidance and those are more appropriately ARM 17.8.749 references. The previous long-term concentration-based limit (200 ppm, rolling 12 month average corrected to 0% oxygen, on a dry basis, was also incorrectly incorporated as a permit limit. The 200-ppm concentration basis was used to establish an annual tons per year limit, which remains in place. As a result, the other long-term RBLC concentration limits (annual) presented in Table BACT-10 are not considered further. DEQ will review future applications regarding the 200-ppm rolling 12-month limit and how it became a limit rather than the basis for an annual PSD avoidance threshold.

Of the remaining precedents, the most stringent precedent identified relies on the use of wet gas scrubbing to achieve the permitted BACT level. As noted, the Chevron – El Segundo, CA precedent is 12 ppmvd.

The most stringent short-term SRU/TGTU based precedent is the Valero Port Arthur Refinery precedent of 97 ppmvd. This limit was required for a new SRP. Further investigation of this precedent has confirmed that this unit was modified and is operating in compliance with its limit.

The remaining short-term SRU/TGTU precedents include the Williams Refining and Riverview Energy Corporation (*i.e.,* both at 150 ppmvd) and multiple facilities, including the CHS Zone D SRP, with short term limits equivalent to the NSPS subpart J/Ja standard of 250 ppmvd.

For purposes of evaluating the impacts, a summary of the precedents are summarized in Table BACT-11.

Table BACT-11 Zone A and Zone D SO_2 Control Technology Hierarchy

Control Option	Control Level (ppmvd @ 0%O_2)
Multistage Claus Unit followed by a TGTU and WGS	12 (72 hr avg.)
Multistage Claus Unit followed by a TGTU	75 (annual)

Multistage Claus Unit followed by a TGTU	97 (24 hr)
Multistage Claus Unit followed by a TGTU	100 (annual)
Multistage Claus Unit followed by a TGTU	150 (24 hr)
Multistage Claus Unit followed by a TGTU	200 (12 month)
Multistage Claus Unit followed by a TGTU	250 (12 hour)

Step 4: Evaluate Most Effective Control Options

The most stringent precedent (*i.e.,* Chevron) is based on the use of WGS. A summary of the costs associated with the retrofit of a WGS on the Zone A and Zone D SRPs is presented in Table BACT-12 with detailed cost estimates included in Appendix D of the application. As shown, the capital costs associated with applying WGS control to the Zone A and Zone D SRPs is $3,598,000 and $3,774,000, respectively and the corresponding total annualized costs are $881,000 and

$938,000. To achieve the Chevron WGS precedents control of 12 ppm results in cost effectiveness estimates of $25,800 and $13,800 per ton of SO_2 control to Zone A and Zone D SRPs respectively. These cost effectiveness values are considered unreasonable and as a result, the use of a WGS is removed from consideration.

Table BACT-12. Summary of Costs Associated with the Application of WGS to the Zone A and Zone D Sulfur Recovery Plants [a]

Category	**Zone A SRP**	**Zone D SRP**
Total Installed Capital Cost, $	3,598,000	3,774,000
Annual Operating Expense, $	485,000	523,000
Total Annualize Cost, $	881,000	938,000
SO_2 Control, ton/yr.	20.9	35.5
Cost Effectiveness, $/ton	25,800	13,800

[a] See Appendix D for detailed cost analysis.

As presented in Table BACT-10, the short-term SRU/TGTU precedents range from 97 ppm to 250 ppm with three precedents that are more stringent than that proposed Zone A and Zone D SRP BACTs. The most stringent is 97 ppm (Valero – TX) for a new unit. No additional information is available regarding how the Valero level was arrived at as part of the BACT process. The second and third are 100 ppm (Valero Port Arthur Refinery) and 150 ppm (Williams Refining and Riverview Energy Corporation). No information was available regarding how these limits were derived and whether any periods of operation are excluded from the limits. Capital improvements at the Zone A and Zone D SRP would be required to ensure that the short-term SO_2 concentration did not exceed 97 ppm. Engineering studies would be required to determine the capital improvements that may be

required but could include such things as the addition of sulfur degassing capability, upstream hydrocarbon knockout facilities, modifications of the Claus catalytic reactors and air blower/control systems, reheater and sulfur condenser improvements, and/or additional ammonia reduction in the SRP feed. If capital improvements were able to achieve the 97 ppm level during the expected range of operation, a maximum SO_2 reduction of
20.9 TPY[25] and 32.5 TPY[26] would be achieved at the Zone A and Zone D SRPs, respectively. Assuming an acceptable cost effectiveness of $10,000 per ton of SO_2 reduced, the maximum cost-effective capital expenditure would be $1,907,000[27] at the Zone A SRP and $2,964,000[28] at

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[25] (200 ppm SO_2 - 97 ppm SO_2) / (200 ppm SO_2) * 40.66 TPY = 20.9 tons/yr.
[26] (250 ppm SO_2 - 97 ppm SO_2) / (250 ppm SO_2) * 53.17 TPY = 32.5 tons/yr.
[27] ($10,000/ton) (20.9 tons/yr.) / 0.1098) = $1,907,000.
[28] ($10,000/ton) (53.17 tons/yr.) / 0.1098) = $2,964,000.

the Zone D SRP. This estimate does not account for any increase in annual operating and maintenance costs. The capital cost of the potential improvements identified above are well above the cost which would be considered cost-effective. As a result, the 97 ppm precedent is removed from consideration. Similarly, the improvements needed to achieve a 100 and 150 ppm level would also be considered cost infeasible.

It is difficult to predict the short-term performance of an SRP because the results are refinery specific based on a number of variables including, but not limited to, the variations in acid gas loading and the rate of change when those variations occur, the concentration of ammonia in the acid gas and the rate of change in the ammonia rate, the amount of hydrocarbon that may reach the SRU/TGTU on an intermittent basis and the ability of the existing air blower system to react and response to the dynamic operation of the incoming acid gases. At the CHS Laurel refinery, ambient temperature (*i.e.,* summer high temperatures) has also been shown to be a factor in SRU/TGTU performance. Additionally, the performance of an SRP is dependent upon catalyst age.

To better characterize the emissions levels that are currently achievable at the Zone A and Zone D SRPs, rolling 12-hour average data was analyzed over a two-year period. Data from periods when the SRP was impacted by startup, shut down, and upset related events (*i.e.,* SO_2 concentration greater than 250 ppm) was not included in the analysis. For the Zone A SRP, the results of the analysis indicate a range of rolling 12-hour average SO_2 concentration from 93 - 248 ppm. For the Zone D SRP, the results of the analysis indicate a range of rolling 12-hour average SO_2 concentration from 6 – 241 ppm. The wide range of actual SO_2 concentration is indicative of the variability of the operation of the Zone A and Zone D SRPs caused by the previously discussed factors. As a result, CHS is proposing SO_2 BACT limits of 250 ppmvd @ 0% O_2 (hourly rolling 12-hour average) for the Zone A and Zone D SRPs. This limit would not be applicable during periods of startup, shut down, or malfunction.

Step 5: Select BACT – Normal Operation

For the Zone A and Zone D SRPs the use of Tail Gas Treatment followed by an incinerator is selected as BACT. The Zone D SRP currently has a short term concentration BACT limit that is as stringent as the limits presented in Table BACT-10. As a result, CHS has determined the existing short term SO_2 limits represent BACT.

The following BACT limits are proposed:

- Zone A SRP: 250 ppmvd at 0% excess O_2 on an hourly rolling 12-hour average, except during periods of startup, shutdown, and malfunction.
- Zone D SRP: 250 ppmvd at 0% excess O_2 on an hourly rolling 12-hour average, except during periods of startup, shutdown, and malfunction.

As discussed above, DEQ has not removed the 200 ppm 12-month rolling average limit but will consider future applications which revisit that limit, as it was used as a basis for PSD avoidance limits on an annual tons per year basis. The 200 ppm limit was never intended to be established as a long term concentration limit, but rather to provide a means for an annual tons per year limit not to be exceeded.

Zone A and Zone D SRP SO_2 BACT – Startup and Shutdown Operation

Steps 1 and 2: Identify Technically Feasible SO_2 Control Options

Two information sources were used to identify the potentially applicable SO_2 emissions controls for periods of startup and shutdown including the RBLC database and regulations applicable to SRPs. Although the majority of the SRP precedents in the RBLC database did not include reference to startup and shutdown, there was information relating to startups and shutdowns for three Valero refineries and the Navajo refinery in New Mexico. The RBLC database included the following precedents relating to SRP startup and shutdown emissions at these refineries:

- Follow written procedures, and
- Minimize duration and frequency of shutdowns.

Additionally, the 2015 revisions to 40 CFR 63 subpart UUU (Refinery MACT II) incorporated requirements for HAP emissions from SRPs during periods of startup and shutdown. Per 40 CFR 63.1568, the subpart UUU requirements are as follows:

- Prepare an operation, maintenance, and monitoring (OMM) plan and operate at all times according to the plan.
- Comply with one of the following three options during periods of startup and shutdown:

- Comply with NSPS standard (250 ppmvd SO_2 at 0% excess air) or meet total reduced sulfur (TRS) limit of 300 ppmvd at 0% excess O_2,
- Send startup and shutdown purge gases to a flare meeting the requirements of 63.670, or

  - Send startup and shutdown purge gases to a thermal oxidizer or incinerator operated at a minimum hourly average temperature of 1200°F in the firebox and a minimum hourly average outlet O_2 concentration of 2% by volume, dry basis. (Note: This is the compliance option currently in place at the three SRPs at the Laurel refinery.)

Each of the identified alternatives is technically feasible.

Steps 3 and 4: Rank Available Control Technologies and Evaluate Most Effective SO_2 Controls

Of the three control precedents identified, one is a general requirement to minimize the duration and frequency of shutdowns and the other two are procedure related. As described below, the CHS Laurel refinery already has programs in place that meet these objectives.

The CHS refinery has a comprehensive program designed to promote safe, environmentally sound, and reliable operation of the refinery between scheduled outages. This program includes the following components:

- Routine Rounds by Operations. Operations staff continually monitor and control the operation of the refinery through the use of a distributive control system (DCS). Unit Operators complete routine rounds through the refinery to verify equipment is operating properly.
- Routine Rounds by Maintenance. Maintenance staff complete walk-throughs of the operating areas to audit the overall performance of equipment and to identify situations where equipment may be developing operating issues.
- Maintenance Work Order System. The refinery uses a tool to prioritize and coordinate the maintenance activities in the refinery.
- Analyzer, Instrument and Emergency Shutdown Preventative Maintenance Program. This program ensures that critical equipment is maintained in good working order.
- Piping Inspection Program. This formal inspection program is designed to prioritize and set the appropriate frequency of piping system inspections.

- Spare Parts Program. This program is intended to keep critical operating equipment components on location.

Additionally, the refinery has implemented detailed operating procedures that are followed to ensure the SRP startup and shutdown process is safe, prevents equipment and catalyst damage, and minimizes SO_2 emissions to the extent possible. These procedures include, but are not limited to, the requirements included in MACT subpart UUU.

Step 5: Select SO_2 BACT

Based on the information presented above, CHS proposes the following permit conditions as BACT during periods of startup and shutdown of the Zone A SRP:

- CHS shall minimize the frequency and duration of startups and shutdowns of the Zone A SRP by operating at all times in accordance with an operation, maintenance, and monitoring plan meeting the requirements of 40 CFR 63.1574(f).
- CHS shall comply with 40 CFR 63 subpart UUU (Refinery MACT II) operating limits at 40 CFR 63.1568(a)(4) during periods of startup and shutdown.

Similarly, CHS proposes to maintain the following permit conditions as BACT during periods of startup and shutdown of the Zone D SRP:

- CHS shall minimize the frequency and duration of startups and shutdowns of the Zone D SRP by operating at all times in accordance with an operation, maintenance and monitoring plan meeting the requirements of 40 CFR 63.1574(f).
- CHS shall comply with 40 CFR 63 subpart UUU (Refinery MACT II) operating limits at 40 CFR 63.1568(a)(4) during periods of startup and shutdown.

For both the Zone A SRP and the Zone D SRP, CHS proposes to use the terms “startup” and “shutdown” as defined in 40 CFR 63.2 to determine when the startup and shutdown conditions are applicable. CHS prefers that the bounds of the startup and shutdown processes not be more specifically defined because the startup and shutdown process do not follow the same steps each time. For example, the startup process after the SRP has been shutdown to warm standby mode is much different than the startup process after the catalyst in the SRU and/or TGTU has been replaced

BACT for Equipment Leaks for #2 Crude Unit, MHC, and NHT

The 2020 MUE (MAQP #1841-43) included the addition of a number of new connectors, valves, pumps, and similar components for movement of gas and liquid raw materials, intermediates, and feedstocks. These components are potential sources of VOC emissions due to leakage from rotary shaft seals, connection interfaces, valve stems, and similar points. As shown in Table BACT-2, components in the #2 Crude Unit, MHC, and NHT will be BACT applicable.[29]

The 2024 RMUE does not change the previous BACT determination for Equipment Leaks. The additional scope does not add new VOC components. As there has been continuous construction on the original 2020 MUE scope, the BACT determination for Equipment Leaks remains unchanged. Components installed per the 2020 MUE (MAQP #1821-43) are operating in accordance with the BACT limits presented in Table BACT-2.

Wastewater Collection System VOC BACT

As part of the RMUE additional oil-water wastewater drains will be installed in the #2 Crude Unit and the Mild Hydrocracker (MHC). This action is a modification to the #2 Crude Unit Wastewater Collection System (#2 CU WCS) emissions unit and the MHC Wastewater Collection System (MHC WCS) that comprises sewer lines, process drains, and junction boxes upstream of the API oil-water separator.[30] In accordance with the BACT requirement at ARM 17.8.819, because this emissions unit is a source of VOC emissions a BACT analysis is provided.

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[29] BACT applicability will be triggered on and emissions unit-by-emissions unit basis when the actual work is performed within a given emissions unit.

[30] This description is meant to be consistent with the individual drain system affected facility defined in 40 CFR 60 subpart QQQ which includes all of the process drains connected to the first common downstream junction box and includes all the drains and common junction boxes, together with their associated sewer lines and other junction boxes, down to the oil-water separator.

BACT Baseline

The minimum emission standards that would meet BACT requirements for VOC emissions from this emissions unit are the equipment design and work practice requirements set forth in the following rules:

- Subpart QQQ of 40 CFR 60, as discussed in Section 4.8.4. This rule requires water seal controls for wastewater collection system drains and sumps.
- Subpart FF of 40 CFR part 61, as discussed in Section 4.9.2. The CHS refinery total annual benzene (TAB) quantity from the facility waste is less than 10 megagrams per year. Therefore, per § 61.355(a)(4)(i), only the monitoring, recordkeeping, and reporting provisions of §61.356 and §61.357 are applicable and the controls standards for the wastewater collection system drains are not applicable.
- Subpart CC of 40 CFR part 63, as discussed in Section 4.10.2, requires compliance with the requirements of 40 CFR 61 subpart FF.

As noted in Section 4.0, the modified individual drain systems are subject to all three of these standards. As a result, the technically feasible control options which are more stringent will be evaluated against this baseline.

Step 1: Identify All Control Options

Potentially available control technologies were identified through a review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database, existing permits and permit applications, and other publicly available information sources. The objective of the analysis was to determine which of the identified technologies were potentially applicable to the modified wastewater collection system. The following techniques for minimizing VOC emissions from #2 CU WCS and MHC WCS were identified: water seal controls on drains; and carbon adsorption and incineration for control of VOC from the drain systems vents.

Step 2: Control Option Technical Feasibility Analysis

Incineration of Vent Gas VOC: Each junction box within the emissions unit is designed to include a vent to allow the wastewater flow entering the box to flow freely without creating back pressure within the upstream lines. As the name infers, junction boxes are located at the junction of one or more drain lines and the main drain line that leads to the oil-water separator. Because junction boxes are located along the collection system lines, a separate incinerator would be needed at each junction box vent or the VOC containing vent gases from each junction box would need to be captured and piped to a common incinerator for control. Either of these incinerator options are considered technically feasible but both are impractical.

Carbon Adsorption of Vent Gas VOC: The practical feasibility issues with the collection of VOC containing vent gases from widely separated junction boxes and piping of those gases to a common incinerator can be eliminated by the use of a dual carbon canister at each junction box to control the VOC vent gases from a given junction box. This option is considered technically feasible.

Step 3: Rank Technically Feasible Control Options

A summary of the identified precedents is presented in Table BACT-13. As shown, these precedents use a combination of water seal controls on drains and carbon adsorption or incineration to control the VOC contained in the wastewater collection system's vents.

Table BACT-13 Summary of Identified Wastewater Collection System VOC Control Precedents

RBLCID	FACILITY NAME	PERMIT ISSUANCE DATE	PROCESS NAME	CONTROL METHOD DESCRIPTION
TX-0731	Corpus Christi Terminal Condensate Splitter	04/10/2015	Petroleum Refining Wastewater & Wastewater Treatment	Process wastewater shall be immediately directed to a covered system. All lift stations, manholes, junction boxes, conveyances, and any other wastewater facilities shall be covered and all emissions routed to a vapor combustor with a guaranteed DRE of 99% for control.
TX-0930	Centurion Brownsville	10/19/2021	Wastewater Collection	Process wastewater routed to wastewater treatment plant via enclosed conveyance system. Emissions vented to a carbon adsorption system limited to 100 ppmv VOC in the exhaust. MLSS concentration in the aeration basins limited to 2,000 mg/L. Equalization tanks and DAF units vent to a catalytic oxidation system with minimum 99% control.

Based on these precedents, the wastewater collection system controls from most to least stringent are as follows:

- Use of closed vent systems and incineration on all vents from the collection system combined with water seal controls on all drains.
- Use of closed vent systems and dual carbon canisters on each vent from the collection system combined with water seal controls on all drains.
- Compliance with the NSPS subpart QQQ, NESHAP subpart FF, and MACT subpart CC standards applicable to individual drain systems.

Step 4: Evaluate More Effective Control Options

The new and replaced #2 CU WCS will be subject to the NSPS subpart QQQ. The MHC WCS is currently subject to NSPS subpart QQQ.

The most stringent control option, use of a closed vent system and incineration on all vent gases from the collection system combined with water seal controls on all drains will result in adverse energy and environmental impacts, due to the use of natural gas in the incinerator (*i.e.,* thermal or catalytic), and the potential oxidation of ammonia to form NO_X in the incinerator. The amount of additional VOC control provided by the use of an incinerator is estimated to be 4.74 tons[31]. Assuming an acceptable cost effectiveness of $10,000 per ton of VOC control, without consideration of the annual operating expenses associated with an incinerator (*e.g.,* annual cost for natural gas and annual cost for catalyst for catalytic oxidation), the maximum cost-effective capital expenditure would be $334,000. The capital cost of an incinerator and the associate piping needed to combine the gases vented from the junction boxes is well above the cost which would be considered cost-effective. Alternatively, if an incinerator were used to control each vent the annual reduction in VOC emissions would be 0.68 tons. Assuming an acceptable cost effectiveness of $10,000 per ton of VOC control, without consideration of the annual operating expenses associated with an incinerator (*e.g.,* annual cost for natural gas and annual cost for catalyst for catalytic oxidation), the maximum cost-effective capital expenditure would be $48,000. The capital cost to purchase and install an incinerator for the control of a single vent is well above the cost which would be considered cost-effective. Additionally, the combustion related NOx and PM emissions would likely exceed VOC reductions. As a result, the

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[31] 1 new junction box, 6 now applicable, assume 1 vent per junction box.
(7 vents) (0.156 lb/hr) (8760hr/yr)/ (2000 lb/ton) (0.99) = 4.74 tons per year

use of an incinerator (thermal or catalytic) is removed from consideration based on its cost infeasibility.

The next most stringent control option, use of closed vent systems and dual carbon canisters on each vent from the collection system combined with water seal controls on all drains has no energy impacts and the only environmental impacts is the disposal of the VOC laden carbon canisters. The ability of carbon canisters to remove VOCs from gaseous streams diminishes when the stream contains a high level of water vapor, increasing the ongoing operating cost of carbon canisters. The amount of additional VOC control provided by a dual carbon canister control system on a vent is estimated to be 0.30 tons per vent control system. Assuming an acceptable cost effectiveness of $10,000 per ton of VOC control, without consideration of the annual operating expenses associated with an absorption system (*e.g.,* annual cost for purchase and disposal of carbon canisters), the maximum cost-effective capital expenditure would be $48,500. The capital cost to purchase and install a dual carbon canister system is well above the cost which would be considered cost-effective. As a result, the use of a dual carbon canister system is removed from consideration based on its cost infeasibility.

Step 5: Select BACT

Based on the evaluation of technically feasible control options provided, the only remaining control option is the implementation of the requirements included NSPS subpart QQQ standard applicable to individual drain systems, which consist of water seal controls for wastewater collection system drains and sumps. This option is proposed as BACT for the new and replace components of the #2 CU WCS and MHC WCS.

Routine Molten Sulfur Trucking BACT Review

Table BACT-14 Summary of Proposed BACT for the Routine Molten Sulfur Trucking Project

Emission Unit	Pollutant	Proposed BACT
Routine molten sulfur trucking – fugitive road dust	Particulate Matter	• Take reasonable precautions to control emissions of airborne particulate matter. This includes treatment of unpaved transport roads with water and/or chemical dust suppressant and routine cleaning of paved transport roads as necessary to control emissions while molten sulfur is being trucked from the refinery.

Description of Molten Sulfur Trucking and Associated Emissions

The transportation of molten sulfur by truck results in fugitive particulate emissions from the transport road. The quantity of dust emissions that will result varies based on a number of factors including the volume of traffic, the weight and speed of the vehicles, silt and moisture content in the road material and the general condition of the road. The proposed routine molten sulfur trucking will occur on an existing partially paved and partially unpaved road.

Particulate Matter BACT Analysis

Steps 1 and 2: Identify Technically Feasible Control Options

To identify the available control options for particulate emissions from similar transport operations, existing Montana air quality and operating permits and Sections 13.2.1 (Paved Roads) and 13.2.2 (Unpaved Roads) of AP-42, Fifth Edition were reviewed. Appendix D includes a summary of the Montana permit precedents.

In the review, the following control options for fugitive road dust were identified:

- Surface improvement such as paving,
- Surface treatment with water and/or chemical dust suppressants, and
- Reduced speed limit.

All of the control options identified are technically feasible for the proposed project.

In addition to the specific control methods, the following regulatory requirements relating to airborne particulate emissions are applicable:

- Take reasonable precautions to control emissions of airborne particulate matter from the production, handling, transportation and storage of any material. Such emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over six consecutive minutes. (ARM 17.8.308(1))
- Take reasonable precautions to control emissions of airborne particulate from streets, roads and parking lots. (ARM 17.8.308(2)).

Step 3: Rank Available Control Technologies

The road dust controls in order of decreasing overall control effectiveness are as follows:

- Surface improvements such as paving. This option involves paving an unpaved road. To be effective, if a paved road is located near unpaved areas, routine cleaning of the paved road surface should be included in the control plan.
- Surface treatment with water and/or chemical suppressants. Watering reduces the likelihood of particles becoming airborne when vehicles pass over the surface. Chemical dust suppressants change the physical characteristics of the existing road surface materials by binding small particles together. There are many factors that impact the effectiveness of these control methods.
- Reduced speed limit. Controlling the speed limit has moderate impact on the degree of emission reduction but is difficult to enforce.

Step 4: Evaluate More Effective Control Options

A portion of the route used for trucking molten sulfur is already paved. Because this is the most effective control option, no further evaluation is required for this section of the route. For transporting molten sulfur on the unpaved sections of the route, the baseline control is using reasonable precautions to control emissions. The only more effective control option is paving the unpaved sections of the route. The estimated annualized cost of paving the unpaved sections of the road is approximately $175,000. This equates to approximately $23,000 per ton of TSP reduced, $92,000 per ton of PM_{10} reduced and $730,000 per ton of $PM_{2.5}$ reduced. Detailed cost data is provided in Appendix D. For this reason, paving the unpaved sections of the molten sulfur transport road is not considered cost effective.

Step 5: Select BACT

Based on this analysis, the following constitutes BACT for molten sulfur trucking:

Take reasonable precautions to control emissions of airborne particulate matter. This includes treatment of unpaved transport roads with water and/or chemical dust suppressant and routine cleaning of paved transport roads as necessary to control emissions while molten sulfur is being trucked from the refinery.

IV. Emission Inventory

RMUE Project

Emission Units	SO_2	NOx	PM-10	PM-2.5	PM	VOC	CO	H_2SO_4
New								
#2 CU Vacuum Heater (005HT0002)	0.84	4.59	0.86	0.86	0.21	0.62	4.59	0.08
Coker Charge Heater H-7502 (removed from scope)								
Boiler 13 (removed from scope)								
Modified								
#2 Crude Main Heater	0.04	0.00	0.31	0.31	0.31	0.23	3.46	0.00
Sulfur Recovery Units (Zone A)	14.17	1.67	0.08	0.08	0.08	0.06	0.93	2.15
Sulfur Recovery Units (Zone D)	7.50	1.81	0.08	0.08	0.08	0.06	0.90	1.14
Refinery Equipment						5.36		
Project Affected								
Process Heaters	0.33	13.77	2.23	2.23	2.23	0.58	8.01	0.65
FCCU Regenerator	0.75	4.38	4.06	4.06	4.67	1.99	5.60	0.11
Storage Tanks						3.72		
2SSWS Ammonia Combustor	0.01	0.31	0.04	0.04	0.04	0.03	0.42	0.00
Hydrogen Production	0.07	4.70	1.30	1.30	1.30	0.03	0.25	0.01
Loading Facilities	0.00	0.08	0.00	0.00	0.00	0.88	0.63	0.00
Coker Unit Vent			0.18	0.18	0.18	0.77		
Coker Coke Handling/Trucking			1.01	0.13	1.03			
Totals	**23.7**	**31.3**	**10.2**	**9.3**	**10.1**	**14.3**	**24.8**	**4.1**
Significance Threshold	**40**	**40**	**15**	**10**	**25**	**40**	**100**	**7**
Significant?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

The project increases shown here are not in addition to the increases approved in MAQP #1821-43 but in place of. Therefore, this RMUE project represents a decrease in nearly all criteria pollutant emissions from the previously approved levels in MAQP #1821-43. The original MUE project increases are shown below.

Emission Units	**SO_2**	**NOx**	**PM-10**	**PM-2.5**	**PM**	**VOC**	**CO**	**H_2SO_4**	**CO_2e**
New									
#2 CU Vacuum Heater (005HT0002)	0.84	4.59	0.86	0.86	0.21	0.62	4.59	0.13	15,680
Coker Charge Heater H-7502	5.92	28.17	5.25	5.25	1.31	3.80	28.17	0.90	95,216
Boiler 13	6.72	27.47	6.82	6.82	1.71	4.94	36.63	1.02	125,103
Modified									
Refinery Equipment						5.22			
Project Affected									
Process Heaters	0.23	14.97	1.60	1.60	1.60	0.45	7.65	0.65	26,698
FCCU Regenerator	0.19	1.10	1.02	1.02	1.17	0.50	1.40	0.03	5,720
Coke Drum Steam Vent			0.96	0.96	0.96	4.01			
Coke Handling/Trucking			1.08	0.14	4.03				
Storage Tanks						3.72			
Sulfur Recovery Units	8.55	1.74	0.09	0.09	0.09	0.06	2.21	1.30	1,413
2SSWS Ammonia Combustor	0.01	0.31	0.04	0.04	0.04	0.03	0.42	0.00	615
Hydrogen Production	0.14	9.19	2.53	2.53	2.53	0.07	0.48	0.02	253,527
Loading Facilities	0.00	0.09	0.00	0.00	0.00	1.15	0.82	0.00	159
Totals	**22.6**	**87.6**	**20.3**	**19.3**	**13.7**	**24.6**	**82.4**	**4.0**	**524,131**
Significance Threshold	**40**	**40**	**15**	**10**	**25**	**40**	**100**	**7**	
Significant?	**NO**	**YES**	**YES**	**YES**	**NO**	**NO**	**NO**	**NO**	

Emission Changes from Original MUE Scope to Current (Tons Per year)

	SO_2	**NOx**	**PM-10**	**PM-2.5**	**PM**	**VOC**	**CO**	**H_2SO_4**
All Emitting Unit Impacts	1.2	-56.3	-10.1	-10.0	-3.6	-10.3	-57.6	0.2

All pollutants would decrease with the exception of a slight increase for SO_2 and H_2SO_4.

The emission inventory below details the project increases associated with the Routine Molten Sulfur Trucking Project.

:Molten Sulfur Trucking Summary of Project Related Emissions Increases, TPY								
Emission Units	**SO_2**	**NOx**	**PM-10**	**PM-2.5**	**PM**	**VOC**	**CO**	**H_2SO_4**
New								
None								
Modified								
Fugitive Road Dust	0	0	1.95	0.24	7.51	0	0	0
Project Affected								
None								
Totals	**0.0**	**0.0**	**2.0**	**0.24**	**7.5**	**0.0**	**0.0**	**0.0**
Significance Threshold	**40**	**40**	**15**	**10**	**25**	**40**	**100**	**7**
Significant?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**

V. Existing Air Quality

The CHS refinery facility is located primarily in Section 16 of Township 2 South, Range 24 East, Yellowstone County, which is a 24-hour sulfur dioxide (SO_2) nonattainment area (NAA) for the 1971 primary SO_2 NAAQS. The NAA status was published in the Federal Register (FR) on March 3, 1978 (43 FR 9010). This NAA is a 2 kilometer (km) (1.2 miles, mi) radius circle centered on the geographic center of the refinery as described in a Department letter to the U.S. Environmental Protection Agency (USEPA) dated April 3, 1991.

The CHS refinery is located about 18.0 km (11.0 mi) southwest of Billings, MT. A prior Billings 1-hour SO_2 NAA was about 23.8 km (14.8 mi) northeast of the refinery. This NAA was designated in regard to the 2010 primary SO_2 NAAQS (78 FR 50 47191, August 5, 2013). The nonattainment area has recently been redesignated as attainment with the 2010 primary SO_2 NAAQS (see 40 CFR 52.1398). It is important to note that in 2017, EPA designated the remainder of Yellowstone County (i.e., excluding the prior Billings NAA) as attainment/unclassifiable with the 2010 primary SO_2 NAAQS. This 2017 designation includes the area around Laurel.

A limited carbon monoxide maintenance plan area also exists in the Billings area, about 17.4 km (10.8 mi) away. Otherwise, the area is currently designated as "Unclassifiable/Attainment" for all other air quality criteria pollutants (40 CFR 81.327). The closest Class I area is the Northern Cheyenne Indian Reservation (NCIR), a non-federal Class I area, about 136 km (85 mi) east of the refinery.

VI. Air Quality Impacts

Ambient Air Impact Analysis

In MAQP #1821-43, an ambient air quality analysis was performed because that project triggered significant PSD thresholds. MAQP #1821-46, is largely the same project with a lower proposed emission increase due to removal of some equipment from the scope. Therefore, the modeling demonstration performed for MAQP #1821-43 is a good surrogate to predict that lower emission levels will continue to not cause or contribute to any violation of a NAAQS. See MAQP #1821-43 for the quantitative modeling analysis used for that project scope.

The CHS Laurel refinery is a major stationary source and a listed source under the Prevention of Significant Deterioration (PSD) regulations of 40 CFR 52.21 in addition to state regulations (ARM 17.8.801 and ARM 17.8.818).

An excerpt taken from MAQP #1821-43, which was modeled at higher rates than the current action:

'RTP Environmental Associates conducted air quality modeling for the proposed Multi-Unit Expansion Project as part of the CHS air quality permit application. This ambient air impact analysis was conducted, pursuant to the requirements of ARM 17.8.820 and ARM 17.8.822 to demonstrate that the proposed modification would not cause or contribute to a violation of any NAAQS, Montana Ambient Air Quality Standards ("MAAQS") or applicable PSD increment (PSD Class II Significant Impact Analysis); pursuant to ARM 17.8.825, and ARM 17.8.1106 to show that the project does not cause or contribute to any adverse impact on visibility within any federal Class I areas (PSD Class I Air Quality Analysis and PSD Class I Significant Impact Analysis); and pursuant to ARM 17.8.824 to show that the project does not cause or contribute to additional impacts to soils, vegetation, and growth (Additional Impact Analysis)'.

The Department determined, based on there being no significant emission increases as determined under the PSD rules, and the previous rigorous modeling conducted under MAQP #1821-43, that the impacts from this permitting action will be negligible to minor. The Department believes it will not cause or contribute to a violation of any ambient air quality standard.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted a private property taking and damaging assessment which is located in the attached environmental assessment.

VIII. Environmental Assessment

An environmental assessment, required by the Montana Environmental Policy Act, was completed for this project. A copy is attached.

DRAFT ENVIRONMENTAL ASSESSMENT

CHS INC.

11/14/2024

Air Quality Bureau

Air, Energy, and Mining Division

Montana Department of Environmental Quality

Table of Contents

Project Overview

COMPANY NAME:	CHS Inc.
EA DATE:	November 14, 2024
SITE NAME:	Laurel CHS Petroleum Refinery
MAQP#:	1821-46
Application Received Date:	September 11, 2024

Location

Township 2 South, Range 24 East Section 16 County: Yellowstone

The facility location is 803 Highway 212 South Laurel, MT 59404

PROPERTY OWNERSHIP: FEDERAL STATE PRIVATE X

Compliance with the Montana Environmental Policy Act

Under the Montana Environmental Policy Act (MEPA), Montana agencies are required to prepare an environmental review for state actions that may have an impact on the human environment. The proposed action is considered to be a state action that may have an impact on the human environment and, therefore, the Department of Environmental Quality (DEQ) must prepare an environmental review. This Environmental Assessment (EA) will examine the proposed action and alternatives to the proposed action and disclose potential impacts that may result from the proposed and alternative actions. DEQ will determine the need for additional environmental review based on consideration of the criteria set forth in Administrative Rules of Montana (ARM) 17.4.608. DEQ may not withhold, deny, or impose conditions on the Permit based on the information contained in this EA (§ 75-1- 201(4), MCA).

Proposed Action

CHS, Inc. has applied for a Montana Air Quality Permit under the Clean Act of Montana proposing revisions to the Multi-Unit Expansion Project (MUE), previously approved under MAQP #1821-43. The earlier permitting action authorized changes in the existing #2 Crude Unit, Mild Hydrocracker, Delayed Coker, and Naphtha Stabilizer. Revisions within this application propose removal of a previously approved process heater and steam boiler, as well as the addition of modifications to the Zone A and Zone D sulfur recovery plants (SRPs). Additionally, unrelated to the previous MUE original project scope or the RMUE project scope, the new application proposes modifications for the Routine Molten Sulfur Trucking Project. CHS has submitted the application with the proposed changes and DEQ will refer to this application as the Revised Multi-Unit Expansion Project (RMUEP). With the scope changes, the RMUEP is no longer subject to PSD preconstruction requirements as emission increases no longer exceed PSD thresholds. Previously, the MUE was subject to PSD for NOx, PM_{10} and $PM_{2.5}$ significant emission increases. The RMUEP removes the addition of the new Coker Charge Heater (H-7502); removes the addition of the proposed new Boiler 13, and no longer shutters the existing Boiler 9. The Routine Loading Sulfur Truck project would add the ability for permanent molten sulfur truck loading from Sulfur Recovery Plants (SRPs) in Zone D and E. Further, the Routine Loading Sulfur Truck Project is not a major modification and not subject to

PSD preconstruction requirements for any pollutant. The project subject to the proposed action would be located on private land in Yellowstone County, Montana. All information included in this EA is derived from the permit application, discussions with the applicant, analysis of aerial photography, topographic maps, and other research tools.

Purpose and Need

Under MEPA, Montana agencies are required to prepare an environmental review for state actions that may have an impact on the human environment. The Proposed Action is considered to be a state action that may have an impact on the human environment and, therefore, DEQ must prepare an environmental review. This EA will examine the proposed action and alternatives to the proposed action and disclose potential impacts that may result from the proposed and alternative actions. DEQ will determine the need for additional environmental review based on consideration of the criteria set forth in ARM 17.4.608. The majority of the equipment modifications within this Proposed Action were previously evaluated under MAQP #1821-43, and the associated EA. Since the earlier approval, DEQ has revised the format of Agency EAs, and therefore the EA has been updated to reflect recent changes. The EA now also recognizes two heaters will no longer be constructed, and also analyses the addition of loading and shipping molten sulfur via trucks, to compliment the current molten sulfur shipping via railcar.

TABLE 1: SUMMARY OF ACTIVITIES PROPOSED IN APPLICATION

Table 1. Summary of Proposed Activities in Application	
General Overview	The proposed action would allow the construction and operation of a new #2 Crude Unit Vacuum Heater, the addition of equipment to provide loading of molten sulfur into trucks, and other refinery changes under the submitted application. This includes modifications to the Zone A and Zone D Sulfur Recovery Plants, which will increase each unit's acid gas processing capacity, and modifications to the #2 Crude Unit Main Heater.
Duration and Timing	Construction: The project began when MAQP #1821-43 was approved in 2020, and was initially approved as a phased project. See Table 2 below for the expected construction schedule. Construction and modifications would continue until completed. Operation: Operation of the new equipment would be consistent with near continuous operation of the refinery. Molten sulfur loading using trucks would be in addition to current railcar loading, and its frequency of use would be dependent upon new markets and rail line availability. Demobilization of construction equipment would occur once work is completed.
Estimated Disturbance	The application has indicated that no new ground disturbance is needed for the construction as the property has been in operation as a petroleum refinery for decades. All equipment is within the existing refinery property boundary.
Equipment	New #2 Crude Unit Vacuum Heater and molten sulfur loading infrastructure.
Location	Township 2 South, Range 24 East Section 16 County: Yellowstone
Personnel on-site	Construction: A significant number of contract personnel would be required over the life of the construction project.

	Operation: Numerous existing CHS staff would oversee operation of the equipment with a small increase in permanent employees (approximately ten).
Location and Analysis Area	The analysis area for this permit action is the area shown in Figure 1.
Air Quality	The Applicant is required to comply with the applicable local, county, state, and federal requirements pertaining to air quality.
Water Quality	This project would not be expected to impact water quality. The Applicant would be required to comply with the applicable local, county, state, and federal requirements pertaining to water quality.
Erosion Control and Sediment Transport	This project is on property currently operating as a petroleum refinery. This project would not contribute to additional erosion or sediment transport. The Applicant is required to comply with the applicable local, county, state, and federal requirements pertaining to erosion control and sediment transport.
Cultural resources	The property is already in use as petroleum refinery, and there would be no effects on cultural resources. The Applicant is required to comply with the applicable local, county, state, and federal requirements pertaining to cultural resources.
Aesthetics	The property is already in use as a petroleum refinery, and there would be negligible effects on aesthetics. The Applicant is required to comply with the applicable local, county, state, and federal requirements pertaining to aesthetics.
Hazardous Substances	This project does not contribute any hazardous substances to the facility. The Applicant is required to comply with the applicable local, county, state, and federal requirements pertaining to hazardous substances.
Weed Control	The Applicant is required to comply with the applicable local, county, state, and federal requirements pertaining to weed control.
Reclamation Plans	The property is already in use as a petroleum refinery, so no reclamation is expected in the short term. If the facility were ever to be mothballed, reclamation would likely be part of shutdown plans.
Solid Waste	This project would have no effect on solid waste in the area. The Applicant is required to comply with the applicable local, county, state, and federal requirements pertaining to solid waste.

Cumulative Impact Considerations	
Past Actions	This is a modification to an existing Montana Air Quality Permit. Specifically, the majority of the proposed changes within this application were previously approved under MAQP #1821-43. Later other separate projects were also approved under MAQP #1821-44 and MAQP #1821-45. There was also a new facility issued MAQP #5261-00 adjacent to the Laurel Refinery in September 2021 (Northwestern Energy Yellowstone Generating Station).
Present Actions	This is a modification to existing MAQP #1821-45. No other air quality permitting actions in the immediate area are being processed. There is on-going litigation related to resolving the CHS Montana Pollution Discharge Elimination System (MPDES) Permit. DEQ has authority for the MPDES program.

Related Future Actions	There are no other known future actions for this facility. DEQ is not aware of any other future actions pending.

Table 2. Construction Schedule

Process Unit	Scope Item	Status	Date Completed	Expected Start of Construction
#2 CU	Replace the main column in #2 CU.	Complete	2021	- -
	Replace the #2 CU vacuum heater.	Complete	2021	- -
	Modifications to the #2 CU Main Heater.	Engineering	- -	Spring 2026
	Modifications in the #2 CU.	In progress	- -	In progress
NHT	Modifications in the NHT.	Complete	2021	- -
DCU	DCU modifications.	Complete	2023	
	Install Second Charge Heater	Removed from scope		
	Fractionator and Absorber tray modifications	Removed from scope		
MHC	Install a new H_2S stripper in the MHC.	Complete	2023	- -
	Modifications in the MHC.	In progress	- -	In progress
	Install a naphtha stabilizer in the MHC	In progress	- -	In progress
Zone A SRP	Modifications in the Zone A SRP.	Engineering	- -	Spring 2025
Zone D SRP	Modifications in the Zone D SRP.	Engineering	- -	Spring 2025
Boilers	Install Boiler 13 and shutdown Boiler 9	Removed from scope		

Project Location: 803 Highway 212 South Laurel, MT 59404

Figure 1. CHS Refinery

EVALUATION OF AFFECTED ENVIRONMENT AND IMPACT BY RESOURCE:

The impact analysis will identify and evaluate whether the impacts are direct or secondary impacts to the physical environment and human population in the area to be affected by the proposed project. Direct impacts occur at the same time and place as the action that causes the impact. Secondary impacts are a further impact to the human environment that may be stimulated, or induced by, or otherwise result from a direct impact of the action (ARM 17.4.603(18)). Where impacts would occur, the impacts will be described.

Cumulative impacts are the collective impacts on the human environment within the borders of Montana that could result from the Proposed Action when considered in conjunction with other past and present actions related to the Proposed Action by location and generic type. Related future impacts must also be considered when these actions are under concurrent consideration by any state agency through pre-impact statement studies, separate impact statement evaluation, or permit processing procedures. The activities identified in Table 1 were analyzed as part of the cumulative impacts assessment for each resource.

The duration is quantified as follows:

- Construction Impacts (short-term): These are impacts to the environment during the construction period. When analyzing duration, please include a specific range of time.
- Operation Impacts (long-term): These are impacts to the environment during the operational period. When analyzing duration, please include a specific range of time.

The intensity of the impacts is measured using the following:

- No impact: There would be no change from current conditions.
- Negligible: An adverse or beneficial effect would occur but would be at the lowest levels of detection.
- Minor: The effect would be noticeable but would be relatively small and would not affect the function or integrity of the resource.
- Moderate: The effect would be easily identifiable and would change the function or integrity of the resource.
- Major: The effect would alter the resource.

1. Geology and Soil Quality, Stability, and Moisture

The CHS site is located on the north-side of the Yellowstone River with approximately 400 feet from the nearest refinery equipment to the river's edge. The elevation is approximately 3,280 feet to 3,290 feet as referenced by the nearest topographic contour on the Montana DEQ GIS website. CHS owns property that touches the Yellowstone River's edge but maintains a buffer of land which is approximately 300 feet wide which does not appear to have been developed. Soils in the area of the refinery are generally identified as silty clay, and silty clay loams

Direct Impacts:

Construction of the proposed new equipment would not require new land disturbance as the land within the refinery boundary has historically already been disturbed. No unique or important geological formations exist in the affected area. Therefore, no impacts to geology would be expected.

The operation of construction equipment for some portions of the project would not impact soil quality, stability and moisture in the affected area. No beneficial direct impacts to soil quality, stability and moisture would be expected because of the proposed project.

Secondary Impacts:

Following construction of the new equipment, no additional or new ground disturbing activities would occur. As permitted, the proposed project would not be expected to cause or contribute to a violation of the applicable primary or secondary national ambient air quality standards (NAAQS). See permit analysis for more detailed information regarding air quality impacts. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. Therefore, any adverse secondary impacts to geology, soil quality, stability and moisture would be long-term and minor. No beneficial secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

Negligible to minor cumulative impacts to geology, stability, and moisture would be expected because CHS is currently operating a petroleum refinery at the site, and emission increases associated with this action are considered small by rules governing air quality.

2. Water Quality, Quantity, and Distribution

This project would not impact any surface or groundwater in the area. The project is proposed on property that is currently operating as a petroleum refinery, and the CHS site has numerous unit operations within the CHS property boundaries.

Direct Impacts:

A very limited amount of water may be required to control fugitive dust emissions from construction activities and for road dust associated with the molten sulfur trucking. Water used to control fugitive dust would likely be sourced off-site and transported to the affected site or sourced from local water resources. Therefore, any adverse direct impacts to water quantity would be short-term and negligible. However, CHS would be required to use reasonable precautions to control fugitive dust resulting from construction and ongoing facility operations. Therefore, fugitive dust generated during construction activities would not be expected to cause or contribute to a violation of the applicable NAAQS for particulate matter. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, water resources, and buildings. Therefore, any adverse direct impacts to water quality would be short-term and negligible to minor.

Secondary Impacts:

Following construction of the proposed facility, no new ground disturbing activities would occur. The ongoing use of unpaved roads to access the proposed facility would occur and would be expected to generate fugitive dust. Further, operation of the permitted equipment would result in the emission of other regulated airborne pollutants. As permitted, the proposed project would not be expected to cause or contribute to a violation of the applicable primary or secondary NAAQS. See permit analysis for more detailed information regarding air quality impacts. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. Therefore, any adverse secondary impacts to geology, soil quality, stability and moisture would be long-term and negligible to minor. No beneficial secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

No cumulative impacts are anticipated from the proposed permitting action as the emission increases are considered minor under air permitting rules.

3. Air Quality

The air quality classification (baseline air quality) for the immediate area is "Unclassifiable or Better Than National Standards" (40 CFR 81.327) for all pollutants, apart from sulfur dioxide (SO_2). The site location is within the Laurel SO_2 nonattainment area (NAA) for the 1971 primary SO_2 National Ambient Air Quality Standards (NAAQS). Air quality in the area affected by the proposed project is currently unclassifiable or in compliance with applicable national ambient air quality standards (NAAQS). Further information on the air quality is contained in the Permit Analysis Section V. Existing Air Quality and Section VI. Ambient Air Impacts Analysis.

Applicants are required to comply with all laws relating to air, such as the Federal Clean Air Act, NAAQS set by the Environmental Protection Agency (EPA), and the Clean Air Act of Montana. In addition, MAQP #1821 provides federally enforceable conditions regarding the emitting units themselves, pollution controls, and also requires the applicant to take reasonable precautions to limit fugitive dust from this location.

Direct Impacts:

Fugitive dust emissions resulting from construction of the new equipment may adversely impact air quality. However, CHS must use reasonable precautions to limit fugitive dust generated during construction and normal facility operations. Other than the SO_2 nonattainment area, no air quality restrictions exist for the affected area; therefore, the proposed project would not be expected to cause or contribute to a violation of any applicable NAAQS. Therefore, any impacts would be short-term, negligible, consistent with existing impacts, and mitigated by implementation of enforceable reasonable precautions as well as permit conditions in MAQP #1821.

The majority of pollutants from the proposed project would be related to the combustion of refinery gases similar in nature to the existing combustion within the refinery heaters. This would result in the release of NO_X, CO, SO_2, VOCs, and particulate matter.

Emission increases under this application result from new process equipment and expanded capacity in the Sulfur Recovery Plants, as well as fugitive road dust associated with the Routine Molten Sulfur Trucking Project. An emission inventory was presented in the Emission Inventory Section IV of the permit analysis for each portion of this application. The MUE emission increases were previously approved in MAQP #1821-43. Under the RMUE Project, the emission increases shown are not in addition to the MUE project but rather in place of the emission increases that would have occurred under the original MUE project. The emission increases for the Routine Molten Sulfur Project are new particulate matter increases under this project application.

Secondary Impacts:

Emissions from the proposed project would use best available control technology or BACT and would not be expected to cause or contribute to a violation of the health and welfare-based NAAQS. See permit analysis section IV for more information regarding air quality impacts. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. See permit analysis for more detailed information regarding air quality impacts

Therefore, any adverse secondary impacts to air quality from facility operations would be long-term and minor**.**

Cumulative Impacts:

Cumulative impacts from the operation of the new equipment are to be restricted by an MAQP and therefore should have minor air quality impacts. The project emission increases are considered minor in comparison to the overall level of emissions currently released from the refinery.

4. Vegetation Cover, Quantity, and Quality

The affected area consists primarily of the petroleum refinery, surrounded by a mix of agricultural and scattered residential property.

Direct Impacts:

Construction of the proposed facility would not require new land disturbance as the land has historically been previously disturbed. Emissions from the proposed project would not be expected to cause or contribute to a violation of the health and welfare-based NAAQS. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. Therefore, any adverse direct impacts would be short-term and negligible to minor. No beneficial direct impacts would be expected because of the proposed project.

Secondary Impacts:

No adverse or beneficial secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

No cumulative impacts are expected as the land has been in operation at a petroleum refinery for many decades.

5. Terrestrial, Avian, and Aquatic Life and Habitats

The affected area consists primarily of the petroleum refinery, surrounded by a mix of agricultural and scattered residential property.

Direct Impacts:

Construction of the new equipment would occur within the petroleum refinery existing boundaries. Therefore, any species displaced by construction activities would likely relocate to nearby, similar habitats. Any adverse direct impacts would be short-term, similar to existing impacts, and minor. No direct impacts to aquatic life and habitats would be expected because of the proposed project. No beneficial direct impacts would be expected because of the proposed project.

Secondary Impacts:

The affected area consists primarily of the petroleum refinery, surrounded by a mix of agricultural and scattered residential property. Emissions from the proposed project would not be expected to cause or contribute to a violation of the health and welfare-based NAAQS. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. Therefore, any adverse secondary impacts would be long-term and negligible to minor. No secondary impacts to aquatic life and habitats would be expected because of the proposed project.

Cumulative Impacts:

No cumulative impacts to terrestrial, avian, and aquatic life would be expected as the facility currently operates nearly 365 days per year, and as such would not provide suitable habitat for many species.

6. Unique, Endangered, Fragile, or Limited Environmental Resources

DEQ has previously conducted a search using the Montana Natural Heritage Program (MTNHP) webpage with file downloads saved to the AQB project file for previous actions at the refinery. As described earlier DEQ conducted research using the MTNHP website and ran the query titled “Environmental Summary Report” dated December 7, 2021. The search was not repeated for this permitting action because the December 2021, report was considered to still be representative of the current status. The report produced the following species of concern (SOC): Snapping Turtle, Spiny Softshell, Sauger, Great Blue Heron, Yellow-billed Cuckoo, Bald Eagle, Grizzly Bear, Isocapnia integra (Alberta Snowfly), and Bat Roost. Some of these species listed as SOC have not been observed within the search polygon. The Alberta Snowfly, Bald Eagle, and Great Blue Heron have been observed within the larger polygon. Avian species may be in the proximity of the CHS Refinery due to the Yellowstone River and undeveloped land buffers surrounding the refinery.

The proposed project is not in core, general or connectivity sage grouse habitat, as designated by the Sage Grouse Habitat Conservation Program (Program) at: http://sagegrouse.mt.gov. Impacts to sage grouse would not be expected.

Direct Impacts:

The Sage Grouse Habitat Conservation Program has stated that the proposed project would not occur in core, general or connectivity sage grouse habitat. Therefore, impacts to sage grouse would not occur. No direct impacts would be expected.

Secondary Impacts:

According to the MTNHP as stated above, there are some species of concern located or potentially located in the affected area. Operation of the new equipment would not require new ground disturbance that has not previously been disturbed. Further, emissions from the proposed project would not be expected to cause or contribute to a violation of the health and welfare-based NAAQS. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. Therefore, any adverse secondary impacts would be long-term and negligible to minor. No beneficial secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

No cumulative impacts would be expected because the site is heavy industrial and not considered to be suitable habitat.

7. Historical and Archaeological Sites

The Montana State Historic Preservation Office (SHPO) was contacted to conduct a file search for historical and archaeological sites on previous CHS actions within Section 16 Township 2 South, Range 24 East. SHPO provided a letter dated December 8, 2021, that indicated there have been fifteen sites within the designated search location. The SHPO report for this permitting action was not repeated because the December report was considered to still be accurate. Some of these sites have been registered, some were ineligible, some eligible and others undetermined. The type of sites that have been recorded include several identified as “historic architecture”. Two sites were identified as “historic railroad”, one was noted as eligible and the other as undermined. It is SHPO’s position that any structure over fifty years of age is considered historic and is potentially eligible for listing on the National Register of Historic Places. If any structures are within the Area of Potential Effect, and are over fifty years old, SHPO recommends that they be recorded, and a determination of their eligibility be made prior to any disturbance taking place.

However, should structures need to be altered, or if cultural materials are inadvertently discovered during this proposed action, SHPO requests their office be contacted for further investigation.

Direct Impacts:

Although the search by SHPO has identified some historical and archaeological sites, the proposed action would not create any new disturbance. Therefore, no impacts to historical and archeological sites would be expected.

Secondary Impacts:

No secondary impacts to historical and archaeological sites are anticipated since the proposed action would not create any new disturbance as the ground has historically been disturbed over decades of refinery operation.

Cumulative Impacts:

No cumulative impacts to historical and archaeological sites are anticipated since the proposed action site is located on land previously disturbed by petroleum refinery operation.

8. Aesthetics

The affected area consists primarily of the petroleum refinery, surrounded by a mix of agricultural and scattered residential property.

Direct Impacts:

Construction of the new equipment would not require new ground disturbance as historically the ground has been previously disturbed. No direct impacts are anticipated.

Secondary Impacts:

No secondary impacts from the project are anticipated.

Cumulative Impacts:

With no direct and secondary impacts, no cumulative impacts would occur.

9. Demands on Environmental Resources of Land, Water, Air, or Energy

The proposed project would require some additional use of land within the existing refinery boundary, and utilize additional energy for the project.

Direct Impacts:

Some direct impacts to land, water and air would be expected because of the proposed project. Further, construction of the proposed new equipment would involve limited operation of heavy equipment and the combustion of refinery gases would be required for the longterm operation. Any adverse direct impacts to energy resources would be short-term and negligible. No beneficial direct impacts would be expected because of the proposed project.

Secondary Impacts:

Some secondary impacts to land, water and air would be expected because of the proposed project. The sulfur trucking project would enable CHS to market molten sulfur to markets not currently available by rail. Shipment via trucks would utilize additional diesel fuel for transportation.

Cumulative Impacts:

No cumulative impacts would be expected from the proposed project.

10. Impacts on Other Environmental Resources

The affected area consists primarily of the petroleum refinery, surrounded by a mix of agricultural and scattered residential property.

Direct Impacts:

Fugitive dust emissions resulting from construction of the proposed facility may adversely impact air quality in the affected area. However, CHS must use reasonable precautions to limit fugitive dust generated from construction activities; therefore, the proposed project would not be expected to cause or contribute to a violation of the applicable NAAQS for particulate matter (fugitive dust). See permit analysis for more detailed information regarding air quality impacts. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. Therefore, any adverse direct impacts to other environmental resources would be short-term and minor. No beneficial direct impacts would be expected because of the proposed project.

Secondary Impacts:

Proposed operations would not be expected to cause or contribute to a violation of the health and welfare-based NAAQS. See permit analysis for more detailed information regarding air quality impacts. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. Therefore, any adverse secondary impacts to other environmental resources would be long-term and minor. No beneficial secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

No other environmental resources, beyond the resource areas already covered within this EA would result in any known additional cumulative impacts.

11. Human Health and Safety

The proposed new equipment would be subject to meeting the permit conditions in MAQP #1821-46.

Direct Impacts:

Construction activities involve the potential for adverse direct impacts to human health and safety. However, construction operations would be subject to OSHA standards, which are designed to be protective of human health and safety. Further, access is limited on the site.

Also, fugitive dust emissions resulting from construction of the proposed facility may adversely impact air quality in the affected area. However, CHS must use reasonable precautions to limit fugitive dust generated from construction activities; therefore, the proposed project would not be expected to cause or contribute to a violation of the applicable NAAQS for particulate matter (fugitive dust). See permit analysis for more detailed information regarding air quality impacts. Primary NAAQS provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. Therefore, any adverse direct impacts to human health and safety would be short-term and negligible to minor.

Since the new equipment would be added to an already heavy industrial site, any noise disturbance would not be expected to increase the noise above existing noise levels.

Secondary Impacts:

Operation of the new equipment would emit regulated air pollutants. However, emissions from the proposed project would use best available control technology or BACT and thus would not be expected to cause or contribute to a violation of the health and welfare-based NAAQS. See permit analysis for more information regarding air quality impacts. Primary NAAQS provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. Therefore, any adverse secondary impacts to human health and safety would be long-term and negligible to minor. No beneficial secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

No cumulative impacts to human health and safety are anticipated as a result of the proposed permitting action because the emissions as described in Section IV of the Permit Analysis would be considered small by rules governing air quality.

12. Industrial, Commercial, and Agricultural Activities and Production

The affected area consists primarily of the petroleum refinery, surrounded by a mix of agricultural and scattered residential property.

Direct Impacts:

The proposed project would allow for additional molten sulfur generation which is a saleable product for the refinery. Recovery of additional sulfur may result in a drop in SO_2 exiting the tail gas incinerators.

Secondary Impacts:
The production of additional molten sulfur would also potentially increase the number of trucks to and from the site related to transporting molten sulfur.

Cumulative Impacts:
No cumulative impacts would be expected.

13. Quantity and Distribution of Employment

Direct Impacts:
A minor increase to the number of employees at the facility or in support of the facility is expected as a result of this permitting action. An increase in permanent staffing of approximately ten would be expected. Any impacts to the quantity and distribution of employment would be expected to be minor.

Secondary Impacts:
An increase in trucking of molten sulfur would require some additional need for truck drivers which likely would be contract trucking and not CHS employees.

Cumulative Impacts:
No cumulative impacts would be expected.

14. Local and State Tax Base and Tax Revenues

The proposed project would continue to be a phased project, and largely occur according to the construction schedule in Table 2, using planned shutdowns and turnarounds to complete the work.

Direct Impacts:
A significant number of contract personnel would be required over the life of the construction project. However, no large-scale impacts to the local and state tax base and tax revenue would be expected beyond the construction completion. Additional employment at CHS and related to the contract trucking of molten sulfur would provide a minor beneficial impact.

Secondary Impacts:
CHS would be responsible for any increased taxes associated with operation of the proposed facility. Therefore, any secondary impacts would be negligible to minor, consistent with existing impacts in the affected area, and beneficial.

Cumulative Impacts:
No cumulative impacts would be expected.

15. Demand for Government Services

Direct Impacts:
The air quality permit has been prepared by state government employees as part of their day-to-day, regular responsibilities. The demands on government services are not expected to increase with this permitting action. No additional permits are expected to be required.

Secondary Impacts:

Following construction of the new equipment, initial and ongoing compliance inspections of facility operations would be accomplished by state government employees as part of their typical, regular duties and required to ensure the facility is operating within the limits and conditions listed in the air quality permit. Therefore, any adverse secondary impacts to demands for government services would be consistent with existing impacts and negligible. No beneficial secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

No cumulative impacts would be expected.

16. Locally-Adopted Environmental Plans and Goals

A review was also conducted of the Laurel 2020 Growth Management Plan which appears to have been adopted in December of 2020. This document captures the vision for the area relative to nearly all aspects of community growth and the vision identified for the area. The Laurel website was reviewed again on October 18, 2024, and the 2020 plan is still the most updated version.

Direct Impacts:

As the Laurel Growth Plan does not address projects specific to the refinery or emission increases, no impact to the Laurel Growth Management Plan would be expected.

Secondary Impacts:

No secondary impacts to the locally adopted environmental plans and goals are anticipated as a result of the proposed action.

Cumulative Impacts:

No cumulative impacts to the locally adopted environmental plans and goals are anticipated since no direct impacts or secondary impacts were identified.

17. Access to and Quality of Recreational and Wilderness Activities

The affected area consists primarily of the petroleum refinery, surrounded by a mix of agricultural and scattered residential property. A community park is located south of the refinery on the south side of the Yellowstone River.

Direct Impacts:

No recreational or wilderness areas occur in the vicinity of the proposed project. Therefore, no direct impacts to access and quality of recreational and wilderness activities would be expected because of the construction or operation phase of the proposed project. The presence of the community park to the south of the refinery would not be impacted beyond the current level of aesthetic impact.

Secondary Impacts:

No recreational or wilderness areas occur in the immediate area; therefore, no secondary impacts to access and quality of recreational and wilderness activities would be expected because of proposed facility operations.

Cumulative Impacts:

No cumulative impacts to access and quality of recreational and wilderness activities are anticipated as a result of the proposed permitting action as the project

18. Density and Distribution of Population and Housing

The affected area consists primarily of the petroleum refinery, surrounded by a mix of agricultural and scattered residential property.

Direct Impacts:

CHS would employ mostly existing staff and/or contracted services to construct and operate the new equipment but would not be expected to otherwise result in a significant increase or decrease in the permanent local population. Therefore, no direct impacts to density and distribution of population and housing would be expected because of the proposed project.

Secondary Impacts:

No secondary impacts would be expected

Cumulative Impacts:

No cumulative impacts to density and distribution of population and housing are anticipated as a result of the proposed permitting. There are no impacts on the density and distribution of population and housing.

19. Social Structures and Mores

DEQ is not aware of any Native American cultural concerns that would be affected by the proposed activity. Based on the information provided by the Applicant, it is not anticipated that this project would disrupt traditional lifestyles or communities.

The existing nature of the area affected by the proposed project is heavy industrial.

Direct Impacts:

Construction and operation of the new equipment would not be expected to affect the existing customs and values of the affected population. Therefore, no direct impacts to the existing social structures and mores of the affected population would be expected because of the proposed project.

Secondary Impacts:

The existing nature of the area affected by the proposed project is the petroleum refinery, surrounded by a mix of agricultural and scattered residential property and would not be expected to affect the existing customs and values of the affected population. Therefore, no secondary impacts to the existing social structures and mores of the affected population would be expected because of the proposed project.

Cumulative Impacts:

No cumulative impacts would be expected.

20. Cultural Uniqueness and Diversity

The existing nature of the area affected by the proposed project is a petroleum refinery, surrounded by a mix of agricultural and scattered residential property. It is not anticipated that this project would cause a shift in some unique quality of the area.

Direct Impacts:

CHS would employ existing staff and/or contracted services to construct and operate the new equipment thus the proposed project would not be expected to otherwise result in an increase or decrease in the local population. Therefore, no direct impacts to the existing cultural uniqueness and diversity of the affected population would be expected because of the proposed project.

Secondary Impacts:

No secondary impacts to the existing cultural uniqueness and diversity of the affected population are anticipated as a result of the proposed action.

Cumulative Impacts:

No cumulative impacts to cultural uniqueness and diversity would occur.

21. Private Property Impacts

The proposed project would take place on privately owned land. DEQ's approval of MAQP #1821-46 permit would not affect the applicant's real property. DEQ has determined that the permit conditions are reasonably necessary to ensure compliance with applicable requirements under the Montana Clean Air Act. Therefore, DEQ's approval of MAQP #1821-46 would not have private property-taking or damaging implications.

As required by 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	X	4. Does the action deprive the owner of all economically viable uses of the property?
	X	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	X	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	X	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	X	7a. Is the impact of government action direct, peculiar, and significant?
	X	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?

YES	NO	
	X	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

22. Other Appropriate Social and Economic Circumstances

Direct Impacts:

DEQ is unaware of any other appropriate short-term social and economic circumstances in the affected area that may be directly impacted by the proposed project. Due to the nature of the proposed action, no direct impacts would be expected because of the proposed project.

Secondary Impacts:

DEQ is unaware of any other appropriate long-term social and economic circumstances in the affected area that may be impacted by the proposed project.

Cumulative Impacts:

No cumulative impacts to any other appropriate social and economic circumstances are anticipated because no direct and secondary impacts were identified.

23. Greenhouse Gas Assessment

Issuance of this permit would authorize construction and operation of equipment for the RMUE project. The earlier permitting action authorized changes in the existing #2 Crude Unit, Mild Hydrocracker, Delayed Coker, and Naphtha Stabilizer. Revisions within this application propose removal of a previously approved process heater and steam boiler, as well as the addition of modifications to the Zone A and Zone D sulfur recovery plants (SRPs). Additionally, unrelated to the previous MUE original project scope or the RMUE project scope, the new application proposes modifications identified as the Routine Molten Sulfur Trucking Project. With the scope changes, the RMUEP is no longer subject to PSD preconstruction requirements as emission increases no longer exceed PSD thresholds. Previously, the MUE was subject to PSD for NOx, PM_{10} and $PM_{2.5}$ significant emission increases. The RMUEP removes the addition of the new Coker Charge Heater (H-7502); removes the addition of the proposed new Boiler 13, and no longer shutters the existing Boiler 9. The Routine Loading Sulfur Truck project would add the ability for permanent molten sulfur truck loading from Sulfur Recovery Plants (SRPs) in Zone D and E. These proposed modifications are included in the Greenhouse Gas Assessment.

The analysis area for this resource is limited to the activities regulated by the issuance of MAQP #1821-46. DEQ has reviewed calculations submitted by CHS for a GHG inventory, and confirmed that calculations largely assume refinery outputs at typical historic rates, with nearly continuous 365-day operation.

CHS routinely performs mandatory greenhouse gas reporting using 40 CFR Part 98 Mandatory

Greenhouse Gas Reporting, and for this application has prepared a GHG assessment based on methodologies contained in Part 98, similar to calculations present in the EPA GHG Calculator tool. Because the Part 98 calculations allow more specific selections which apply to fuel gases used at the refinery, the CHS GHG inventory is accepted for the project analysis. Because the Part 98 calculations are likely to be more accurate for the refinery, they are used in this GHG assessment.

For the purpose of this analysis, DEQ has defined greenhouse gas emissions as the following gas species: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and many species of fluorinated compounds. The range of fluorinated compounds includes numerous chemicals which are used in many household and industrial products. Other pollutants can have some properties that also are similar to those mentioned above, but the EPA has clearly identified the species above as the primary GHGs. Water vapor is also technically a greenhouse gas, but its properties are controlled by the temperature and pressure within the atmosphere, and it is not considered an anthropogenic species.

Direct Impacts

The combustion of fossil fuels at the site would release GHGs, primarily CO_2, N_2O and much smaller concentrations of uncombusted fuel components including methane (CH_4) and other volatile organic compounds (VOCs).

Where DEQ normally uses the EPA Simplified GHG Calculator Tool, it has substituted the more detailed 40 CFR Part 98 calculations for this project. This tool totals carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4) and reports the total as CO_2 equivalent (CO_2e) in metric tons CO_2e. The calculations in Part 98 are widely accepted to represent reliable calculation approaches for developing a GHG inventory. DEQ has determined EPA's Scope 1 GHG impacts as defined in the Inventory Guidance for Greenhouse Gas Emissions are appropriate under MEPA for this Proposed Action. Scope 1 emissions are defined as direct GHG emissions that occur from sources that are controlled or owned by the organization (EPA Center for Corporate Climate Leadership). DEQ's review of Scope 1 emissions is consistent with the agency not evaluating downstream effects of other types of impacts.

One time construction related GHGs for the RMUE were estimated to be 39.8 metric tons of CO_2e. The RMUE operational annual GHG emissions were estimated to be 114,297 metric tons of CO_2e using the Part 98 calculations. The increase in molten sulfur trucking GHG emissions at the site would be minimal as travel distance on the CHS property is only approximately 1.4 miles per trip. This would equate to between 2 and 4 metric tons of CO_2e for truck hauling on site.

This review does not include an assessment of GHG impacts in quantitative economic terms, otherwise known as evaluating the social cost of carbon. DEQ instead calculates potential GHG emissions and provides a narrative description of GHG impacts. This approach is consistent with Montana Supreme Court caselaw and the agency's discussion of other impacts in this draft EA. See Belk v. Mont. DEQ, 2022 MT 38, ¶ 29.

Secondary Impacts

GHG emissions contribute to changes in atmospheric radiative forcing, resulting in climate change impacts. GHGs act to contain solar energy loss by trapping longer wave radiation emitted from the Earth's surface and act as a positive radiative forcing component (BLM 2021).

Per EPA's website "Climate Change Indicators", the lifetime of carbon dioxide cannot be represented with a single value because the gas is not destroyed over time. The gas instead moves between air, ocean, and land mediums with atmospheric carbon dioxide remaining in the atmosphere for thousands of years, due in part to the very slow process by which carbon is transferred to ocean sediments. Methane remains in the atmosphere for approximately 12 years. Nitrous oxide has the potential to remain in the atmosphere for about 109 years (EPA, Climate Change Indictors). The impacts of climate change throughout the specified region of the state of Montana include changes in flooding and drought, rising temperatures, and the spread of invasive species (BLM 2021).

Cumulative Impacts

Montana recently used the EPA State Inventory Tool (SIT) to develop a greenhouse gas inventory in conjunction with preparation of a possible grant application for the Community Planning Reduction Grant (CPRG) program. This tool was developed by EPA to help states develop their own greenhouse gas emission inventories, and relies upon data already collected by the federal government through various agencies. The inventory specifically deals with carbon dioxide, methane, and nitrous oxide and reports the total as CO_2e. The SIT consists of eleven Microsoft Excel based modules with pre-populated data that can be used with default settings or in some cases, allows states to input their own data when the state believes their own data provides a higher level of quality and accuracy. Once each of the eleven modules is filled out, the data from each module is exported into a final "synthesis" module which summarizes all the data into a single file. Within the synthesis file, several worksheets display the output data in a number of formats such as GHG emissions by sector and GHG emissions by type of greenhouse gas.

DEQ has determined the use of the default data provides a reasonable representation of the greenhouse gas inventory for the various sectors of the state, and the estimated total annual greenhouse gas inventory by year. The SIT data from EPA is currently only updated through the year 2021, as it takes several years to validate and make new data available within revised modules. DEQ maintains a copy of the output results of the SIT.

DEQ has determined that the use of the default data provides a reasonable representation of the GHG inventory for all the state sectors, and an estimated total annual GHG inventory by year. At present, annually, Montana accounts for 47.77 million metric tons of CO_2e based on the EPA SIT for the year 2021. This project may contribute up to 114,297 metric tons per year of CO_2e. The first year construction and full year operating estimated emission of 114,337 metric tons of CO_2e from this project would contribute 0.24% of Montana's total annual CO_2e emissions. Construction related GHG emissions would be limited to approximately 39.8 metric tons of CO_2e with the rest being annual GHG emissions primarily from refinery heaters.

GHG emissions that would be emitted as a result of the proposed activities would add to GHG emissions from other sources. The No Action Alternative would contribute less GHGs as the Proposed Action Alternative because the refinery operations covered in the project would not expand.

PROPOSED ACTION ALTERNATIVES

No Action Alternative: In addition to the proposed action, DEQ must also considered the "no action" alternative. The "no action" alternative would deny the approval of MAQP #1821-46. The applicant would lack the authority to conduct the proposed activity. Any potential impacts that would result from the proposed action would not occur. The no action alternative forms the baseline from which the impacts of the proposed action can be measured.
If the Applicant demonstrates compliance with all applicable rules and regulations required for approval, the "no action" alternative would not be appropriate.

Other Reasonable Alternative(s): No other alternatives were considered.

CONSULTATION

DEQ engaged in internal and external efforts to identify substantive issues and/or concerns related to the proposed project. Internal scoping consisted of internal review of the environmental assessment document by DEQ staff. External scoping efforts also included queries to the following websites.

A review of the Laurel City website, and listed department information did not indicate any specific planning documents that would be relative to this permitting action. The Laurel Growth Plan would not be impacted by the project.

MAQP #1821-45, MAQP #1821-43, MAQP #1821-46 Application, EPA State Inventory Tool, and Part 98 Calculations submitted by CHS with the application.

PUBLIC INVOLVEMENT

The public comment period for this permit action will occur from 11/13/2024 through 11/29/2024. Public comments may be submitted to the DEQ through the DEQ website, email, written letter, or in person.

OTHER GOVERNMENTAL AGENCIES WITH JURISDICTION

The proposed project would be located on privately owned land. All applicable state and federal rules must be adhered to, which, at some level, may also include other state, or federal agency jurisdiction.

NEED FOR FURTHER ANALYSIS AND SIGNIFICANCE OF POTENTIAL IMPACTS

When determining whether the preparation of an environmental impact statement is needed, DEQ is required to consider the seven significance criteria set forth in ARM 17.4.608, which are as follows:

- The severity, duration, geographic extent, and frequency of the occurrence of the impact;
- The probability that the impact will occur if the proposed action occurs; or conversely, reasonable assurance in keeping with the potential severity of an impact that the impact will not occur;
- Growth-inducing or growth-inhibiting aspects of the impact, including the relationship or contribution of the impact to cumulative impacts – identify the parameters of the proposed action;
- The quantity and quality of each environmental resource or value that would be affected, including the uniqueness and fragility of those resources and values;
- The importance to the state and to society of each environmental resource or value that would be affected.
- Any precedent that would be set as a result of an impact of the proposed action that would commit the department to future actions with significant impacts or a decision in principle about such future actions; and
- Potential conflict with local, state, or federal laws, requirements, or formal plans.

CONCLUSIONS AND FINDINGS

The DEQ finds that this action results in minor impacts to air quality and GHG emissions in Yellowstone County, Montana.

No significant adverse impacts would be expected because of the proposed project. As noted through the draft EA, the severity, duration, geographic extent and frequency of the occurrence of the impacts associated with the proposed air quality project would be limited.

As discussed in this EA, DEQ has not identified any significant impacts associated with the proposed actions for any environmental resource. DEQ does not believe that the activities proposed by the Applicant would have any growth-inducing or growth-inhibiting aspects, or contribution to cumulative impacts. The Laurel Refinery site does not appear to contain known unique or fragile resources.

There are no unique or known endangered fragile resources in the project area and no new disturbance would be required for this project.

There would be negligible impacts to view-shed aesthetics as the new equipment would not likely be distinguishable from existing refinery equipment.

Demands on the environmental resources of land, water, air, or energy would not be significant. Some additional truck traffic may occur due to truck shipping of molten sulfur.

Impacts to human health and safety would not be significant as the refinery is restricted to authorized personnel.

Issuance of a Montana Air Quality Permit #1821-46 to the Applicant does not set any precedent that commits DEQ to future actions with significant impacts or a decision in principle about such future actions. If the Applicant submits another modification or proposes to amend the permit, DEQ is not committed to issuing those revisions. DEQ would conduct an environmental review for any subsequent permit modifications sought by the Applicant pursuant to MEPA. DEQ would make permitting decisions based on the criteria set forth in the Clean Air Act of Montana.

Issuance of the Permit to the Applicant does not set a precedent for DEQ's review of other applications for Permits, including the level of environmental review. The level of environmental review decision is made based on case-specific consideration of the criteria set forth in ARM 17.4.608.

Finally, DEQ does not believe that the proposed air quality permitting action by the Applicant would have any growth-inducing or growth inhibiting impacts that would conflict with any local, state, or federal laws, requirements, or formal plans.

Based on a consideration of the criteria set forth in ARM 17.4.608, no significant adverse impacts to the affected human environment would be expected because of the proposed project. Therefore, preparation of an Environmental Impact Statement or EIS is not required, and the draft EA is deemed the appropriate level of environmental review pursuant to MEPA.

PREPARATION AND APPROVAL

EA and Significance Determination prepared by:

Craig Henrikson
Environmental Engineer, PE

Environmental Assessment Reviewed by: Craig Jones, MEPA Coordinator

Approved by: Eric Merchant, Supervisor, Air Quality Permitting Services Section, Air Quality Bureau

REFERENCES

- MAQP #1821-466 Application received from CHS, Inc. Dated September 11, 2024

City of Laurel Website https://cityoflaurelmontana.com/community

City of Laurel Growth Plan Policy:

https://cityoflaurelmontana.com/sites/default/files/fileattachments/planning/page/133/laurel_growth_policy_final_2020.pdf

- Previous CHS MAQP #1821-43
- Additional CHS Correspondence received on September 25, 2024, and on October 7, 2024.
- Attachment from the CHS September 25, 2024, correspondence (GHG inventory).
- EPA GHG Calculator Tool https://www.epa.gov/statelocalenergy/state-inventory-and-projection-tool. Version dated May 2023 in the Introduction Tab.
- EPA State Inventory Tool, https://www.epa.gov/statelocalenergy/state-inventory-and-projection-tool Version 2024.1.
- Previous State Historic Preservation Office files received for MAQP #1821-45.
- Montana Natural Resource Information System (NRIS) Data downloaded for MAQP #1821-45. https://mtnhp.org/mapviewer/
- Results of State Inventory Tool model run for Version 2024.1. Model results run by AQB staff on March 7, 2024.
- 2021 BLM Specialist Report on Annual Greenhouse Gas Emissions and Climate Trends, https://www.blm.gov