Air, Energy & Mining Division

Date of Posting: July 2, 2025

Joe Dauner
Calumet Montana Refining, LLC
1900 10th Street Northeast
Great Falls, MT 59404

Sent via email: joseph.dauner@calumetspecialty.com

RE: Final and Effective Montana Air Quality Permit #2161-40

Dear Mr. Dauner,

Montana Air Quality Permit (MAQP) #2161-40 for the above-named permittee is deemed final and effective as of July 2, 2025, by the Montana Department of Environmental Quality (DEQ). All conditions of the Decision remain the same. A copy of final MAQP #2161-40 is enclosed.

For DEQ,

Craig Henrikson

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

Montana Air Quality Permit #2161-40

Calumet Montana Refining, LLC
1900 10th Street Northeast
Great Falls, MT 59404

Final and Effective Date:
July 2, 2025

MONTANA AIR QUALITY PERMIT

Issued to: Calumet Montana Refining, LLC
1900 10th Street Northeast
Great Falls, MT 59404

MAQP: #2161-40
Application Received: 06/06/2025
Application Deemed Complete: 06/06/2025
Department Decision Issued: 06/16/2025
Permit Final: 07/02/2025

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to Calumet Montana Refining, LLC (Calumet) pursuant to Sections 75-2-204, 211, 213, and 215 of the 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

Calumet operates a petroleum refinery located at the NE¼ of Section 1, Township 20 North, Range 3 East, in Cascade County, Montana. The refinery is located along the Missouri River in Great Falls, Montana.

B. Permitted Facility

The major permitted equipment at Calumet includes:

- #1 Crude Unit
- #2 Crude Unit
- Fluid Catalytic Cracking Unit (FCCU)
- Hydrogen Plants #1 and #2
- Catalytic Reformer Unit
- Naphtha Hydrodesulfurization (HDS)
- Diesel HDS
- Catalytic Poly Unit
- Hydrogen Fluoride (HF) Alkylation Unit
- Deisobutanizer Unit
- Sodium Hydrosulfate (NaHS) Unit
- Hydrotreater Unit (HTU)
- Polymer-Modified Asphalt (PMA) Unit
- Storage Tanks (heated asphalt, crude oil, middle distillates, and petroleum products)
- Gasoline Truck Loading with a vapor combustor unit (VCU)
- Gasoline Railcar Loading with a VCU
- Asphalt/Diesel Loading and Crude Oil/Gas Oil Rail Unloading Rack
- Primary Flare #1 and Secondary Flare #2

- Miscellaneous Tanks; Utilities (Boilers (#1, #2 and #3), North and South Cooling Towers, Wastewater Treatment including new Dissolved Air Flotation Unit)
- Catalytic Thermal Oxidizer for Remediation Project

A complete list of permitted equipment for Calumet is contained in Section I.A. of the Permit Analysis.

C. Current Permit Action

On June 6, 2025, DEQ received a request to administratively update MAQP #2161-39 for conditions related to final emissions limits and standards from the 2002 Consent Decree (United States of America, et al., v. Navajo Refining Company, LP, U.S. District Court for the District of New Mexico, Civ. No. 01-1422LH (2002)). Unrelated to the administrative Consent Decree updates, Calumet also requested the removal of Hot Oil Heater 1904 (H-1904), since it was not constructed. Permit conditions for H-1904 were removed. Additionally, equipment which has been transferred to Montana Renewables, LLC, has been removed from the MAQP.

SECTION II: Limitations and Conditions

A. General Facility Conditions

1. Calumet shall comply with all applicable requirements of ARM 17.8.340, which references 40 Code of Federal Regulations (CFR) Part 60, Standards of Performance for New Stationary Sources (NSPS):

   a. Subpart A – General Provisions shall apply to all equipment or facilities subject to an NSPS Subpart as listed below.

   b. Subpart Dc – Standards of Performance for Small Industrial–Commercial Institutional Steam Generating Units for which construction, modification, or reconstruction is commenced after June 9, 1989. This Subpart applies to Boiler #3 and Hot Oil Heater H-1903.

   c. Subpart J – Standards of Performance for Petroleum Refineries applies to all fuel gas combustion devices with the exception of those subject to 40 CFR 60 Subpart Ja, in which case 40 CFR 60 Subpart Ja applies.

      1. FCCU regenerator: for carbon monoxide (CO) and sulfur dioxide (SO_2) (ARM 17.8.749).

      2. Heaters and boilers (ARM 17.8.749).

   d. Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification Commenced after May 14, 2007 (H-2101, H-2102, Boiler #3, flare system, fuel gas treatment unit (FGT), sour water stripper (SWS) and Hot Oil Heater H-1903.

e. Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984.

f. Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture shall apply to all asphalt storage tanks that processes and stores only non-roofing asphalts and was constructed or modified since May 26, 1981. Following replacement as part of the Asphalt Upgrades Project, Tank #55 will be subject to the opacity requirements under Subpart UU.

g. Subpart VV – Standards of Performance for Equipment Leaks of Volatile Organic Compounds (VOC) in the Synthetic Organic Chemicals Manufacturing Industry, shall apply to this refinery as required by 40 CFR 60, Subpart GGG and 40 CFR 63, Subpart CC.

h. Subpart VVa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.

i. Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the NaHS Unit, HTU, Hydrogen Plant #1, and any other equipment as appropriate. A monitoring and maintenance program as described under 40 CFR 60, Subpart VV shall be instituted. Once DEQ receives written notification that the HTU has been modified, the source will no longer be regulated by this condition.

j. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006. Unless Calumet demonstrates exemption from this standard, the standard applies to compressors, valves, pumps, pressure relief devices, sampling connection system, open-ended valves and lines, flanges, and connectors that are part of the Low Sulfur Fuels expansion project. The piping components within the PMA Unit will be subject to Subpart GGGa following the Asphalt Upgrades Project. The piping components within the HTU will be subject to Subpart GGGa following the Refinery Reconfiguration Project.

k. Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to the refinery's, individual drains, junction boxes, and oil-water separators.

2. Calumet shall comply with all applicable requirements of ARM 17.8.341, as specified by 40 CFR Part 61, National Emissions Standards for Hazardous Air Pollutants:

   a. Subpart A – General Provisions applies to all equipment or facilities subject to a NESHAP subpart as listed below.

   b. Subpart FF – National Emission Standard for Benzene Waste Operations.

3. Calumet shall comply with all applicable requirements of ARM 17.8.342, as specified by 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants (NESHAP) for Source Categories:

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

   b. Subpart Q – NESHAP for Industrial Process Cooling Towers shall apply if Calumet uses chromium-based water treatment chemicals in the cooling tower water.

   c. Subpart R – NESHAP for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), as specified under Subpart CC.

   d. Subpart CC – NESHAP from Petroleum Refineries shall apply to, but not be limited to, the bulk loading racks (including the gasoline truck loading and railcar loading racks), certain valves and pumps in the alkylation unit, miscellaneous process vents, storage vessels, wastewater, and equipment leaks. The gasoline loading rack provisions in Subpart CC require compliance with applicable Subpart R provisions, and the equipment leak provision requires compliance with applicable 40 CFR 60, Subpart VV provisions.

   e. Subpart UUU – NESHAP from Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, shall apply to, but not be limited to, the FCCU and the Catalytic Reformer Unit.

   f. Subpart EEEE – NESHAP for Organic Liquids Distribution (Non-Gasoline) shall apply to, but not be limited to, Tank # 1 – diethylene glycol monoether (DEGME) and the naphtha loading rack.

   g. Subpart FFFF – NESHAP for Miscellaneous Organic Chemical Manufacturing shall apply to, but not be limited to, miscellaneous organic chemical manufacturing process units (MCPU) which includes the facility-wide collection of MCPU and heat exchange systems, wastewater, and waste management units associated with the same MCPU. The piping fugitive components, wastewater components, and transfer racks at the refinery that are used to load renewable products produced by the MRI RDU shall comply with the applicable Subpart FFFF requirements. An affected source is new if construction or reconstruction of the source commenced after April 4, 2002.

h. Subpart DDDDD – NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters shall apply to, but not be limited to, all boilers and process heaters. This will now include the HTU Fractionation Heater (Hot Oil Heater H-1903).

B. CD Required Language and Emission Credit Generation

1. General Prohibition: Calumet shall not generate or use any NO_X, SO_2, PM, VOC, or CO emissions reductions that result from any projects conducted or controls required pursuant to the Consent Decree (Civ. No. 01-1422LH) as netting reductions or emissions offsets in any PSD, major non-attainment and/or minor New Source Review ("NSR") permit or permit proceeding. Exception to the General Prohibition: Notwithstanding the general prohibition set forth above, Calumet may use 10 tons per year of NO_X and 20 tons per year of SO_2 from the CD Emissions Reductions as credits or offsets in any PSD, major non-attainment and/or minor NSR permit or permit proceeding occurring after March 2002, provided that the new or modified emissions unit: (1) is being constructed or modified for purposes of compliance with Tier 2 gasoline or low sulfur diesel requirements; and (2) already has emissions limits at the time of permitting as follows.

   a. For heaters and boilers, a limit of 0.020 pounds NO_X per million British thermal units (Btu) or less on a 3-hour rolling average basis;

   b. For heaters and boilers, a limit of 0.10 grains of hydrogen sulfide per dry standard cubic foot of fuel gas or 20 ppmvd SO_2 corrected to 0% O_2 both on a 3-hour rolling average;

   c. For heaters and boilers, no liquid or solid fuel firing capabilities;

   d. For FCCUs, a limit of 20 ppmvd NO_X corrected to 0% O_2 or less on a 365-day rolling average basis;

   e. For FCCUs, a limit of 25 ppmvd SO_2 corrected to 0% O_2 or less on a 365-day rolling average basis; and

   f. For SRPs, NSPS Subpart J emission limits.

2. Conditions Precedent to Utilization of the exception to the general prohibition against the generation or utilization of CD Emissions Reductions set forth above is subject to the following conditions:

   a. Under no circumstances shall Calumet use CD Emissions Reductions for netting and/or offsets prior to the time that actual CD Emissions Reductions have occurred;

b. CD Emissions Reductions may be used only at the Calumet refinery;

c. The CD Emissions Reductions provisions of the CD are for purposes of the CD only and Calumet may not use CD Emissions Reductions for any purpose, including in any subsequent permitting or enforcement proceeding, except as provided herein; and

d. Calumet still shall be subject to all federal and state regulations applicable to the PSD, major non-attainment and/or minor NSR permitting process.

3. Definitions

"CEMS" shall mean continuous emissions monitoring system.

"Fuel Oil" shall mean any liquid fossil fuel with sulfur content of greater than 0.05% by weight.

"Shutdown" shall mean the cessation of operation of equipment for any purpose.

"Startup" shall mean the setting in operation of equipment for any purpose.

"Torch Oil" shall mean FCCU feedstock or light cycle oil that is combusted in the FCC regenerator to assist in starting up or restarting the FCCU.

C. Emission Control Requirements

Calumet shall install, operate, and maintain the following equipment and practices as specified:

1. Flare #1 (primary flare) shall be equipped with a flare gas scrubber (ARM 17.8.749 and ARM 17.8.752).

2. Flare #2 (secondary flare) must maintain a water seal except during periods of startup, shutdown, or malfunction as defined in this permit. These periods of startup, shutdown, and malfunction shall not exceed 9 hours per year based on a 12-month rolling average (ARM 17.8.749).

3. Hydrogen plant reformer heaters shall only be fired with commercially available natural gas, which may include recycled gas from the hydrogen plants, and shall not be fired with refinery fuel gas or refinery Liquefied Petroleum Gas (LPG). The HTU Heater (H-1701) shall be fired with only purchased natural gas or refinery fuel gas that meets 40 CFR 60, Subpart J or Ja requirements. The purge (vent) gas used as fuel in the hydrogen plant reformer heaters shall be sulfur-free (ARM 17.8.752).

4. All process heaters in the #2 Crude Unit (H-2101, H-2102) shall be equipped with ULNB (ARM 17.8.749 and ARM 17.8.752).

5. Storage Tanks

a. Storage tanks #47, #48, and #49 shall be used to store middle distillates with a vapor pressure equal to or less than kerosene/Jet A and shall be equipped with fixed roofs (ARM 17.8.749 and ARM 17.8.752).

b. Storage tanks #100 and #101 shall be used to store #5 Fuel Oil or NaHS and shall be equipped with a fixed roof (ARM 17.8.749).

c. Storage tank #52 shall be used to store gasoline and shall be equipped with an external floating roof, mechanical shoe seal, and a gasketed sliding cover with a pole sleeve and pole wiper on each guide pole (ARM 17.8.752).

d. Storage tanks #123, #126 and #127 shall be used to store unleaded gasoline and shall be equipped with an external floating roof and a mechanical shoe seal (ultracheck safe sleeve guide pole) (ARM 17.8.749 and ARM 17.8.752).

e. Storage tank #124 shall be used to store Naphtha (ARM 17.8.749).

f. Storage tanks #122, #124, #126, #145B, #201, #202, and #203 shall be equipped with dual-seal external floating roofs with guide pole sleeves (ARM 17.8.752).

g. Storage tank #125 shall be maintained in heavy liquids service only, with maximum vapor pressure of contents contained not to exceed 0.5 pounds per square inch absolute (psia). The tank shall be equipped and operated as a fixed roof tank with pressure/vacuum vent and submerged fill (ARM 17.8.749 and ARM 17.8.752).

h. Storage tanks #55, #56, #69, #110, #130, #132, #133, #135, #137, #138, and #139 shall be used for heavy oil or asphalt (ARM 17.8.749).

i. Storage tanks #201, #202, and #203 shall be used for crude oil service (ARM 17.8.749).

j. Storage tanks #8 and #9 shall be used for caustic service (ARM 17.8.749).

k. Storage tank #58 shall be used for middle distillates and shall be equipped and operated with a fixed roof and a submerged fill (ARM 17.8.752).

l. Asphalt tank heater #160 shall burn only natural gas or refinery fuel gas in compliance with 40 CFR 60 Subpart Ja (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60, Subpart Ja).

m. Hot Oil Heater (H-1903) shall burn only natural gas that complies with 40 CFR 60 Subpart Ja (ARM 17.8.752 and 40 CFR 60 Subpart Ja).

n. Calumet shall not cause to be discharged into the atmosphere from any asphalt tank constructed or modified since May 26, 1981, exhaust gases with opacity greater than 0% except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown for clearing (ARM 17.8.340 and 40 CFR 60, Subpart UU).

o. For any asphalt tank constructed between November 23, 1968, and May 26, 1981, or any other tank constructed since November 23, 1968, Calumet shall not cause to be discharged into the atmosphere exhaust gases with an opacity of 20% or greater, averaged over 6 consecutive minutes (ARM 17.8.304).

p. For any tank constructed prior to November 23, 1968, Calumet shall not cause to be discharged into the atmosphere exhaust gases with an opacity of 40% or greater, averaged over 6 consecutive minutes (ARM 17.8.304).

q. Tanks and process vessels #55, #130, #132, #133, D-1901 and D-1907 shall utilize a carbon adsorption device on the vent to atmosphere for VOC control (ARM 17.8.752).

r. Hot Oil Heater H-1903 shall meet the following emission control requirements:

   1. Install and operate ULNB for NO_X control (ARM 17.8.752).

   2. CO emissions shall not exceed 0.04 lb/MMBtu (HHV), based on a 1-hour average (ARM 17.8.752).

   3. Meet work practice standards under 40 CFR 63, Subpart DDDDD (ARM 17.8.749 and 40 CFR 63, Subpart DDDDD).

6. Pressure Vessels – All pressure vessels in HF Acid service, except storage tanks, shall be vented to the flare system (ARM 17.8.749 and ARM 17.8.752).

7. The HF Alkylation Unit shall be operated and maintained as follows (ARM 17.8.749 and ARM 17.8.752):

   a. All valves used shall be high quality valves containing high quality packing.

   b. All open-ended valves shall be of the same quality as the valves described above. They shall have plugs or caps installed on the open end.

c. All pumps used in the alkylation plant shall be fitted with the highest quality state-of-the-art mechanical seals.

d. All pumps shall be monitored and maintained as described in 40 CFR 60.482-2 and all control valves shall be monitored and maintained as described in 40 CFR 60.482-7. All other potential sources of VOC leaks shall be inspected quarterly for evidence of leakage by visual or other detection methods. Repairs shall be made promptly as described in 40 CFR 482-7(d). Records of monitoring and maintenance shall be maintained on site for a minimum of 2 years.

e. All process drains shall consist of water seal traps with covers.

f. All equipment shall be operated and maintained as described in 40 CFR 60.692-2, 60.692-6, and 60.693-1. Inspection reports shall be made available for inspection upon request.

g. The Alkylation Unit process heater shall burn only natural gas or fuel gas in compliance with 40 CFR 60, Subpart J (ARM 17.8.749 and 40 CFR 60, Subpart J).

8. The PMA Unit shall be operated and maintained as follows:

a. All open-ended valves shall have plugs or caps installed on the open end (ARM 17.8.752).

b. All pumps in the PMA unit shall be equipped with standard single seals (ARM 17.8.752).

c. The PMA Unit Polymer Handling Operations shall be equipped with partial or full enclosures at automated transfer points (ARM 17.8.752).

d. The PMA Unit Prilled Sulfur Handling Operations shall be equipped with full enclosures at automated transfer points (ARM 17.8.752).

e. PMA Unit piping fugitive components which are in VOC service will be required to comply with 40 CFR 60, Subpart GGGa and the equipment leak provisions found in 40 CFR 60.482-la through 60.482-10a. PMA Unit piping fugitive components which are in Organic HAP service will be required to comply with the existing source equipment leak provisions found in 40 CFR 63.648 through 649 of 40 CFR 63, Subpart CC. (ARM 17.8.752, ARM 40 CFR 60, Subpart GGGa and 40 CFR 63, Subpart CC).

9. Calumet shall ensure that the NaHS Unit, HTU, Hydrogen Plant #1, and any other equipment as appropriate, comply with the applicable requirements in 40 CFR 63 Subpart GGG and Subpart GGGa, including (ARM 17.8.342, 40 CFR 63 Subpart GGG and Subpart GGGa):

a. All valves used shall be high quality valves containing high quality packing.

b. All open-ended valves shall be of the same quality as the valves described above. They shall have plugs or caps installed on the open end.

c. A monitoring and maintenance program as described under 40 CFR 60, Subpart VV shall be instituted.

10. Calumet shall ensure that all process drains consist of water seal traps with covers for the HTU, Hydrogen Units, and any other equipment as appropriate (ARM 17.8.342 and 40 CFR 63 Subpart QQQ).

11. North Cooling Tower and South Cooling Tower

a. Calumet shall minimize particulate matter emissions from the cooling towers by maintaining the drift eliminators equipped on the cooling towers and controlling the total dissolved solids in the cooling water. The maximum total dissolved solids of cooling tower water shall not exceed 1,500 parts per million (ARM 17.8.752).

b. Calumet shall minimize VOC emissions from the cooling towers by complying with the applicable requirements of 40 CFR 63 Subpart CC as applicable to heat exchange systems, as defined in this subpart. This condition is not intended to expand the requirements and applicability of 40 CFR 63 Subpart CC (ARM 17.8.752, ARM 17.8.302, ARM 17.8.342, and 40 CFR 63 Subpart CC).

c. Calumet shall comply with 40 CFR 63 Subpart Q, during any timeframe in which 40 CFR 63 Subpart Q is applicable (ARM 17.8.749, ARM 17.8.302, ARM 17.8.342 and 40 CFR 63 Subpart Q).

12. Calumet must install, operate, and maintain an ULNB and flue gas recirculation (FGR) on Boiler #3 (ARM 17.8.752).

13. Boiler #3 shall only combust pipeline quality natural gas or refinery fuel gas with no SWS overhead gas. SWS overhead gas is considered refinery fuel gas and shall not be burned in Boiler #3 (ARM 17.8.749 and ARM 17.8.752).

14. When the SO_2/O_2 Continuous Emissions Monitoring System (CEMS) is operational on the boiler #1 and Boiler #2 stack, Calumet may combust SWS overhead in Boiler #1 and Boiler #2. Combustion of the SWS overhead and any other refinery fuel gas shall meet the applicable limitations in 40 CFR 60 Subpart J (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60 Subpart J).

15. The gasoline and distillates truck loading rack shall be operated and maintained as follows:

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

b. Calumet collected vapors shall be routed to the vapor combustion unit (VCU) at all times. In the event the VCU is inoperable, Calumet may continue to load distillates with a Reid vapor pressure of less than 27.6 kilopascals, provided DEQ is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.752).

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 and 40 CFR 63, Subpart CC).

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 position from passing to another loading position (ARM 17.8.342).

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

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

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

    iii. Calumet 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. Calumet shall notify the owner or operator of each non-vapor-tight cargo tank loaded at the truck loading rack within 3 weeks after the loading has occurred; and

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

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

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

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

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

g. Calumet shall ensure that loadings of gasoline cargo tanks at the truck 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. Calumet shall ensure that the terminal and the cargo tank vapor recovery systems are connected during each loading of a gasoline cargo tank at the truck loading rack (ARM 17.8.342).

i. Calumet shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the gasoline loading rack as described in 40 CFR 60.482-1 through 60.482-10.

j. The truck loading rack VCU stack shall be at least 35 feet above grade (ARM 17.8.749).

16. The East railcar loading rack and VCU shall be operated and maintained as follows when loading gasoline and naphtha:

a. Calumet's gasoline railcar loading rack shall be equipped with a vapor recovery system designed to collect the organic compounds displaced from railcars during gasoline and naphtha loading and vent those emissions to the VCU (ARM 17.8.342 and 40 CFR 63, Subpart CC and ARM 17.8.752).

b. Calumet shall operate and maintain the VCU to control VOC and hazardous air pollutant (HAP) emissions during the loading of gasoline or naphtha in the gasoline railcar loading rack. Calumet's collected vapors shall be routed to the VCU at all times (ARM 17.8.752).

c. The vapor recovery system shall be designed to prevent any VOC vapors collected at one loading position from passing to another loading position (ARM 17.8.749).

d. Loading of gasoline and naphtha railcars shall be restricted to the use of submerged fill and dedicated normal service (ARM 17.8.752).

e. Calumet shall ensure that loading of gasoline and naphtha into railcars at the gasoline railcar loading rack are made only into railcars equipped with vapor recovery equipment that is compatible with the terminal's vapor recovery system (ARM 17.8.749).

f. Loadings of gasoline 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 40 CFR 63, Subpart CC, and ARM 17.8.752).

   i. Calumet 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 railcar loading rack;

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

   iii. Calumet 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. Calumet shall notify the owner or operator of each non-vapor-tight cargo tank loaded at the railcar loading rack within 3 weeks after the loading has occurred; and

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

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

      B. 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 passes, the annual certification test described in 40 CFR 63.425(e).

g. Calumet shall ensure that the terminal's and the railcar's vapor recovery systems are connected during each loading of gasoline and naphtha into railcar at the gasoline railcar loading rack (ARM 17.8.749).

h. The vapor recovery and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline railcar from exceeding 4,500 Pa (450 mm of water) during gasoline loading. This level shall not be exceeded when measured by the procedures specified in 40 CFR 60.503(d) (ARM 17.8.342 and 40 CFR 63, Subpart CC).

i. No pressure-vacuum vent in the permitted terminal's vapor recovery system shall begin to open at a system pressure less than 4,500 Pa (450 mm of water) (ARM 17.8.749).

j. Calumet shall comply with the applicable provisions of 40 CFR 60, Subpart VV, including Calumet shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the gasoline loading rack as described in 40 CFR 60.482-1 through 60.482-10 (ARM 17.8.749, ARM 17.8.342 and 40 CFR 63, Subpart CC).

k. The gasoline railcar loading rack VCU stack exhaust exit shall be at least 30 feet above grade (ARM 17.8.749).

17. Calumet shall not combust any fuel gas with a hydrogen sulfide (H_2S) concentration in excess of 230 milligram per dry standard cubic meter (mg/dscm) equivalent to 0.10 grains per dry standard cubic foot (gr/dscf) in any applicable fuel gas combustion device (ARM 17.8.340 and 40 CFR 60, Subpart J).

18. For fuel gas combustion devices where construction, reconstruction, or modification commenced after May 14, 2007, Calumet shall not burn any fuel gas that contains H_2S in excess of 162 parts per million volume, dry basis (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 17.8.749, and 40 CFR 60 Subpart Ja).

19. Calumet shall not combust fuel oil as defined in this permit, in any combustion unit, except torch oil as defined in this permit may be used in the FCCU Regenerator during FCCU startups (ARM 17.8.749)

20. The #1 crude unit's stack height shall be at least 150 feet above ground level (ARM 17.8.749).

21. VOC from the dual phase extraction wells and subsequent vapor/liquid separator associated with the AOC-16 remediation project shall be collected and oxidized via an electric catalytic thermal oxidizer designed for 99% destruction efficiency of VOC and HAP during normal operation (ARM 17.8.752).

D. Emission Limitations

1. Plant-wide refinery emissions shall not exceed (ARM 17.8.749):

   a. SO_2:

      Annual 1,515 tons per year (TPY) on a rolling 12-month sum basis
      Daily 4.15 tons/rolling 24-hours

   b. CO:

      Annual 4,700 TPY on a rolling 12-month sum basis
      Daily 12.9 tons/rolling 24-hours

2. Boiler #1 and #2 emissions shall not exceed:

   a. SO_2 (ARM 17.8.749):

      i. Annual: 648 TPY on a rolling 12-month sum basis
      ii. Hourly: 148 pounds per hour (lb/hr) averaged over 1 year
      iii. 174 lb/hr averaged over a 24-hour period
      iv. 355 lb/hr averaged over a 3-hour period

   b. Oxides of Nitrogen (NO_X): 76.50 lb/hr (ARM 17.8.752)

   c. CO (ARM 17.8.752):

      i. Annual 4.4 TPY on a rolling 12-month sum basis
      ii. Hourly 1.00 lb/hr

   d. Opacity from Boilers #1 and #2 shall not exceed 40% averaged over any 6 consecutive minutes (ARM 17.8.304).

3. Boiler #3 emissions:

   a. The maximum rated capacity of Boiler #3 shall not exceed 60.5 MMBtu/hr on a higher heating value basis (ARM 17.8.749).

b. Opacity from the Boiler #3 shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

c. NO_X emissions shall not exceed 0.019 pounds per million British thermal units (lb/MMBtu) (1.15 lb/hr) on a 3-hour average basis (ARM 17.8.752 and ARM 17.8.749).

d. Refinery fuel gas combusted in Boiler #3 shall not contain H_2S at a concentration greater than 162 ppmv on a 3-hour rolling average basis (ARM 17.8.752).

e. CO emissions shall not exceed 0.034 lb/MMBtu based on a 3-hour average (ARM 17.8.752).

4. HTU Heater (H-1701)

   a. The HTU Heater firing rate shall not exceed 22.5 MMBtu/hr on a HHV, 365-day average basis, averaged daily (ARM 17.8.749).

   b. NO_X emissions shall not exceed the limit of 0.07 lb/MMBtu (ARM 17.8.752), and 6.9 TPY (ARM 17.8.749).

   c. CO emissions shall not exceed the limit of 0.88 lb/hr or 3.84 TPY (ARM 17.8.752).

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

5. Naphtha Splitter Reboiler (H-0405)

   a. The firing rate of the Naphtha Splitter Reboiler H-0405 shall not exceed 9.9 MMBtu/hr on a HHV, 365 day rolling average basis, averaged daily (ARM 17.8.749).

   b. NO_X emissions shall not exceed 0.03 lb/MMBtu on a HHV basis (ARM 17.8.749).

6. Naphtha HDS Heater (H-0402a)

   a. The firing rate of the Naphtha HDS Heater H-0402a shall not exceed 13.6 MMBtu/hr on a HHV, 365 day rolling average basis, averaged daily (ARM 17.8.749).

   b. NO_X emissions shall not exceed 0.03 lb/MMBtu on a HHV basis (ARM 17.8.749).

7. Reformer Heater (H-0403)

a. The firing rate of the Reformer Heater H-0403 shall not exceed 24.2 MMBtu/hr on a HHV, 365 day rolling average basis, averaged daily (ARM 17.8.749).

b. NO_X emissions shall not exceed 0.098 lb/MMBtu on an HHV basis (ARM 17.8.749).

8. Hydrogen Plant #1 Reformer Furnace Stack

a. NO_X emissions shall not exceed the limit of 0.07 lb/MMBtu, 1.90 lb/hr, or 8.3 TPY (ARM 17.8.752).

b. CO emissions shall not exceed the limit of 0.93 lb/hr or 4.1 TPY (ARM 17.8.752).

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

9. Hydrogen Plant #2

a. NO_X emissions shall not exceed 0.033 lb/MMBtu based on the higher heating value (HHV) (ARM 17.8.752 and ARM 17.8.749), and 11.56 TPY on a rolling 12-month sum (ARM 17.8.749).

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

10. #2 Crude Unit process heaters (Atmospheric Heater H-2101 and Vacuum Heater H-2102).

a. The maximum rated capacity of each unit shall not exceed the following on a higher heating value basis (ARM 17.8.749):

i. #2 Crude Atmospheric Heater H-2101: 71.0 MMBtu/hr.

ii. #2 Crude Vacuum Heater H-2102: 27.0 MMBtu/hr.

b. Each fuel combustion device must be equipped with an ULNB and NO_X emissions shall not exceed the following on a higher heating value basis:

i. H-2101: 0.035 lb/MMBtu, 30-day rolling average basis as may be monitored via CEMS.
ii. H-2101: 0.042 lb/MMBtu, 3-hour rolling average basis as may be monitored via CEMS (ARM 17.8.749).

iii. H-2102: 0.040 lb/MMBtu, 3-hr average basis, as may be monitored via source testing.

c. For process heaters (natural draft) with a rated capacity of greater than 40 MMBtu/hr-HHV, Calumet shall comply with 40 CFR 60 Subpart Ja. Each applicable process heater must meet the NO_X emission limits in either (b)(i) or (b)(ii), as follows (ARM 17.8.340 and 40 CFR 60, Subpart Ja):

i. 40 ppmvd (corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

ii. 0.040 lb/MMBtu-HHV basis determined daily on a 30-day rolling average basis.

d. Each applicable fuel gas combustion device shall comply with 40 CFR 60 Subpart Ja by meeting the applicable SO_2 or H_2S emission limit in 40 CFR 60 Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja):

i. Calumet shall not discharge or cause the discharge of any gases into the atmosphere that contain SO_2 in excess of 20 ppmv (dry basis, corrected to 0-percent excess air) determined hourly on a 3-hour rolling basis; and SO_2 in excess of 8 ppmv (dry basis corrected to 0-percent excess air) determined daily on a 365-successive calendar day rolling average basis; or

ii. Calumet shall not burn in any fuel gas combustion device any fuel that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis, and H_2S in excess of 60 ppmv determined daily on a 365-successive calendar day rolling average basis.

e. Calumet shall control PM/PM_{10} and $PM_{2.5}$ emissions from each heater by utilizing good combustion practices and only combusting low sulfur fuels (ARM 17.8.752):

i. PM/PM_{10} emissions from each heater shall not exceed 0.00051 lb/MMBtu, and

ii. $PM_{2.5}$ emission from each heater shall not exceed 0.00042 lb/MMBtu.

f. Calumet shall control CO emissions from each process heater using good combustion practices. CO emissions from each heater shall not exceed 0.055 lb/MMBtu (ARM 17.8.752).

g. Calumet shall control CO_2e emission from each process heater by using low carbon fuels, good combustion practices and an energy efficient design. The CO_2e emissions shall not exceed (ARM 17.8.752):

i. 142 lb/MMBtu for the Crude Heater (H-2101) and Vacuum Heater (H-2102).

ii. 141 lb/MMBtu for the Combined Feed Heater (H-4101) and Fractionator Feed Heater (H-4102).

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

11. Flare System (Flare #1 and Flare #2)

    a. Calumet shall comply with the requirements of 40 CFR 60 Subpart Ja (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60, Subpart Ja).

12. Gasoline Truck Loading Rack

    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 and ARM 17.8.752).

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

    c. The total NO_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).

    d. Calumet shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU:

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

        ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% carbon dioxide (CO_2) (ARM 17.8.752).

13. Gasoline Railcar Loading Rack

    a. The total VOC emissions to the atmosphere from the VCU due to loading gasoline into railcars shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.342 and 40 CFR Part 63.422, and ARM 17.8.752).

    b. The total CO emissions to the atmosphere from the VCU due to loading gasoline into cargo tanks shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.752).

    c. The total NO_X emissions to the atmosphere from the VCU due to loading gasoline into cargo tanks shall not exceed 4.0 mg/L of gasoline loaded (ARM 17.8.752).

    d. Calumet shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU:

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

ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO_2 (ARM 17.8.752).

14. FCCU

Calumet shall not cause or authorize to be discharged into the atmosphere from the FCCU emissions in excess of:

a. 15.0 lb/hr of PM (ARM 17.8.749).

b. Opacity shall not exceed 40%, except for one 6-minute average in any 1 hour (ARM 17.8.304).

c. CO

i. 500 ppmvd, at stack oxygen (or, "uncorrected") (40 CFR 63, Subpart UUU and 40 CFR 60, Subpart J),

ii. 500 ppmvd, 1-hour average at 0% O_2 (ARM 17.8.749),

iii. 100 ppmvd, on a 365-day rolling average at 0% O_2 (ARM 17.8.749).

d. SO_2

i. 50 ppmvd, on a 7-day rolling average at 0% O_2. SO_2 emissions during periods of startup, shutdown, or malfunction of the FCCU shall not be used in determining compliance with the 7-day rolling average SO_2 emissions limit provided that during such periods Calumet implements good air pollution control practices to minimize SO_2 emissions (ARM 17.8.749).

ii. 25 ppmvd, on a 365-day rolling average at 0% O_2 (ARM 17.8.749)

e. NO_X

i. 87 ppmvd, on a 7-day rolling average at 0% $O_{2.}$. NOx emissions during periods of startup, shutdown, or malfunction of the FCCU shall not be used in determining compliance with the 7-day rolling average NOx emissions limit provided that during such periods Calumet implements good air pollution control practices to minimize NOx emissions (ARM 17.8.749).

ii. 68 ppmvd, on a 365-day rolling average at 0% O_2.

15. NO_X Umbrella Limit incorporated in MAQP #2161-30 and revised in MAQP #2161-38 (ARM 17.8.749):

In MAQP #2161-30, NO_X emissions were limited over multiple emitting units for purposes of avoiding PSD. Boiler #3, Crude Unit #2 Atmospheric Heater H-2101, Crude Unit #2 Vacuum Heater H-2102, Combined Feed Heater H-4101, MHC Reactor Fractionation Feed Heater H-4102, Hydrogen Plant #3 Reformer Heater H-3815A, and Hydrogen Plant #3 Reformer Heater H-3815B are considered new units for the underlying net emissions increase calculations. Boiler #1, Boiler #2, Crude Unit #1 Atmospheric Heater, and Crude Unit #1 Vacuum Heater are considered existing units.

NO_X emissions from the following units, combined, shall not exceed 103.02 tons per year as determined monthly on a rolling 12-month basis, for purposes of PSD avoidance for NO_X associated with the expansion project as permitted in MAQP #2161-30. The NO_X emission limit shall be reduced by the potential NO_X emissions from the RDU Combined Feed Heater (H-4101) of 3.83 TPY and from the Hydrogen Plant #3 Reform Heaters (H-3815A and H-3815B) of a combined 29.93 TPY, upon written notification to DEQ by Calumet that the sources have been transferred to MRI. This umbrella limit may be reduced in steps as sources are transferred. In MAQP #2161-38, H-4102 has been identified as continuing to operate at the MRL facility and therefore, the umbrella limit of 69.26 TPY has been further reduced by the NOx PTE of H-4102 (5.26 TPY). Calumet shall not exceed 64.0 TPY after the transfer of H-4101, H-3815A and H-3815B, while H-4102 continues to operate at MRL.

With exception of any unit equipped with NO_X CEMS verified via RATA, NO_X emissions shall be determined utilizing emissions factors determined via monthly portable analyzer results for 12 months, after which, emissions factors shall be determined based on source tests. Fuel flow shall be monitored continuously, and heat content of fuel gas determined no less than weekly. The monthly and rolling 12-month sums for the previous month shall be determined and recorded by no later than the 25th of each month. This limit is effective beginning with the first full month following the start of portable analyzer testing. Portable analyzer testing shall begin within 90 days after finalization of MAQP #2161-30 or upon startup of any affected unit, whichever is later.

- Boiler #1
- Boiler #2
- Crude Unit #1 Atmospheric Heater
- Crude Unit #1 Vacuum Heater
- Boiler #3
- Crude Unit #2 Atmospheric Heater H-2101
- Crude Unit #2 Vacuum Heater H-2102

16. CO Umbrella Limit incorporated in MAQP #2161-30 and revised in MAQP #2161-38 (ARM 17.8.749):

    In MAQP #2161-30, CO emissions were limited over multiple emitting units for purposes of avoiding PSD. Boiler #3, Crude Unit #2 Atmospheric Heater H-2101, Crude Vacuum Heater H-2102, Combined Feed Heater H-4101, MHC Reactor Fractionation Feed Heater H-4102, Hydrogen Plant #3 Reformer Heater H-3815A, and Hydrogen Plant #3 Reformer Heater H-3815B were new units. Boiler #1, Boiler #2, Crude Unit #1 Atmospheric Heater, and Crude Unit #1

Vacuum Heater are considered existing units for the underlying net emissions increase calculations.

CO emissions from the following units, combined, shall not exceed 55.08 tons per year as determined monthly on a rolling 12-month basis, for purposes of PSD avoidance for CO associated with the expansion project as permitted in MAQP #2161-30. The CO emission limit shall be reduced by the potential CO emissions from the RDU Combined Feed Heater (H-4101) of 6.02 TPY and from Hydrogen Plant #3 Reform Heaters (H-3815A and H-3815B) of a combined 17.61 TPY, upon written notification to DEQ by Calumet that the sources have been transferred to MRI. This umbrella limit may be reduced in steps as sources are transferred. In MAQP #2161-38, H-4102 has been identified as continuing to operate at the MRL facility and therefore, the umbrella limit of 31.45 TPY has been further reduced by the CO PTE of H-4102 (7.23 TPY). Calumet shall not exceed 24.22 TPY after the transfer of H-4101, H-3815A and H-3815B, while H-4102 continues to operate at MRL.

With exception of any unit equipped with CO CEMS verified via RATA, CO emissions shall be determined utilizing emissions factors determined via monthly portable analyzer results for 12 months, after which, emissions factors shall be determined based on annual source tests. Fuel flow shall be monitored continuously, and heat content of fuel gas determined no less than weekly. The monthly and rolling 12-month sums for the previous month shall be determined and recorded by no later than the 25th of each month. This limit is effective beginning with the first full month following the start of portable analyzer testing. Portable analyzer testing shall begin within 90 days after finalization of MAQP #2161-30 or upon startup of an affected unit, whichever is later.

- Boiler #1
- Boiler #2
- Crude Unit #1 Atmospheric Heater
- Crude Unit #1 Vacuum Heater
- Boiler #3
- Crude Unit #2 Atmospheric Heater H-2101
- Crude Unit #2 Vacuum Heater H-2102

17. Catalytic Thermal Oxidizer (AOC-16 Remediation Project)

   a. The catalytic thermal oxidizer shall operate with no visible emissions, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours, as determined by an initial performance test utilizing Method 22 to be conducted within 90 days of startup of the unit (ARM 17.8.752, ARM 17.8.749).

   b. Calumet shall operate all equipment to provide the maximum air pollution control for which it was designed (ARM 17.8.752(2)).

E. Testing and Monitoring Requirements

1. Refinery Fuel Gas Combustion Devices:

   a. Calumet shall install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases (except for SWS overhead gas) in accordance with the requirements of 40 CFR Part 60, Subparts A and J, for all fuel gas combustion devices, except those subject to 40 CFR 60 Subpart Ja, in which the monitoring requirements for 40 CFR 60 Subpart Ja applies (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60 Subpart J).

   b. Calumet shall install, calibrate, maintain, and operate an instrument for continuously monitoring and recording the concentration (dry basis) of H_2S in fuel gases (except for SWS overhead gas) in accordance with the requirements of 40 CFR Part 60, Subparts A and Ja in order to demonstrate compliance with all refinery fuel gas combustion devices subject to 40 CFR 60 Subpart Ja (ARM 17.8.340 and 40 CFR 60 Subpart Ja).

   c. Calumet shall install, operate, calibrate and maintain on each applicable heater, an instrument for continuously monitoring and recording the concentration (dry basis, 0-percent excess air) of NO_X emissions into the atmosphere pursuant to 40 CFR 60, Subpart Ja or complete biennial performance tests in accordance with 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60 Subpart Ja).

   d. By July 1, 2008, Calumet shall install and operate an SO_2 and O_2 CEMS and a volumetric flow rate monitor on the stack for the #1 and #2 Boilers, to be used as the primary analytical instrument to determine compliance with state and federal SO_2 requirements. By July 1, 2008, Calumet shall initially certify the #1 and #2 Boiler SO_2/O_2 CEMS and the volumetric flow rate monitor in accordance with 40 CFR Part 60, Performance Specifications 2 and 3 and 6. After initial certification, Calumet shall conduct annual Relative Accuracy Test Audits (RATA) of the #1 and #2 Boiler SO_2/O_2 CEMS, and volumetric flow rate monitoring conformance with 40 CFR 60, Appendix F. After initial certification, Calumet shall also continue to implement all of the requirements of 40 CFR 60.13 and 40 CFR 60, Appendices B and F for the #1 and #2 Boilers SO_2/O_2 CEMS and flow rate monitor. (May 2008 Administrative Order on Consent and ARM 17.8.749).

2. Units Subject to the NO_X Umbrella Limitation of Section II.

   a. Each unit subject to the NO_X umbrella limitation and not equipped with validated (RATA conducted) CEMS meeting 40 CFR 60 Subpart A and Ja requirements, shall have annual Method 7E source tests (or testing as approved by DEQ), with the first source test to be conducted no later than 12 months after finalization of MAQP #2161-30. All testing shall be conducted concurrently with CO testing. Units equipped with NO_X CEMS shall conduct a RATA as required. Emissions factors in units of lb/MMBtu shall be determined from the most recent emissions testing (portable analyzer test, source test, or performance test (i.e. RATA testing, as applicable) (ARM 17.8.749).

b. For any refinery fuel gas fired units subject to the NO_X umbrella limit in which a NO_X CEMS verified via a RATA is not in place, Calumet shall, at least once every calendar month, conduct concurrent NO_X and CO monitoring utilizing a portable analyzer and submit the results in a format as provided by Attachment 1 on a semiannual basis (within 45 days of the end of each semiannual period). Such monitoring must begin no later than 90 days after finalization of MAQP #2161-30 and shall be conducted for no less than 12 consecutive months following finalization of MAQP #2161-30. Any subsequent source test indicating noncompliance with any NO_X or CO limit shall reinstate this requirement, until no less than 4 quarters of compliance is again achieved. Emissions factors in units of lb/MMBtu shall be determined from the most recent emissions testing (portable analyzer test, source test or performance test, as applicable) (ARM 17.8.749).

c. A source testing protocol meeting the minimum requirements of Attachment 1 shall be submitted to DEQ no later than 30 days after finalization of MAQP #2161-30, and such revisions as may be required submitted such that an approved source test protocol is in place within 60 days after finalization of MAQP #2161-30. Calumet shall conduct portable analyzer testing as required by DEQ (ARM 17.8.749).

d. Portable analyzer testing shall not be required in any month in which source testing or performance testing is performed (ARM 17.8.749).

3. Units Subject to CO Umbrella Limitation of Section II.

a. For all units subject to the CO Umbrella Limitation of Section II. in which a validated CO CEMS is not utilized, Calumet shall test for CO currently with testing for NO_X (ARM 17.8.749). For any units equipped with NO_X CEMS but no CO CEMS, CO testing concurrent with NO_X RATA Testing is acceptable. Units equipped with CO CEMS shall conduct a RATA as required and determine lb/MMBtu emissions factors during the RATA testing (ARM 17.8.749).

b. For any refinery fuel gas fired units subject to the CO umbrella limit in which a CO CEMS verified via a RATA is not utilized, Calumet shall, at least once every calendar month, conduct concurrent NO_X and CO monitoring utilizing a portable analyzer and submit the results in a format as provided by Attachment 1 on a semiannual basis (within 45 days of the end of each semiannual period). Such monitoring must begin no later than 90 days after finalization of MAQP #2161-30 and shall be conducted for no less than 12 consecutive months following finalization of MAQP #2161-30. Any subsequent source test indicating noncompliance with any NO_X or CO limit shall reinstate this requirement, until no less than 4 quarters of compliance is again achieved (ARM 17.8.749).

c. A source testing protocol meeting the minimum requirements of Attachment 1 shall be submitted to DEQ no later than 30 days after finalization of MAQP #2161-30, and such revisions as may be required submitted such that an approved source test protocol is in place within 60 days after finalization of MAQP #2161-30. Calumet shall conduct portable analyzer testing as required by DEQ (ARM 17.8.749).

4. Crude Heater #2 H-2101 shall be equipped with NO_X CEMS in compliance with 40 CFR 60, Subpart A and Ja by no later than June 30, 2018 (ARM 17.8.749).

5. SWS Overhead Gas
   a. Calumet shall comply with the SO_2 monitoring requirements contained in 40 CFR 60 Subpart J during all times when the SWS overhead gas is combusted in the boilers (Boiler #1 and/or Boiler #2). Calumet shall conduct SO_2 stack monitoring to demonstrate compliance with 20 ppm (dry basis, zero percent excess air) SO_2 limitation (ARM 17.8.749, and 40 CFR 60 Subpart J).

6. Calumet shall install and use the following continuous emission monitoring system (CEMS) on the FCCU:

   a. SO_2 and O_2 (ARM 17.8.749 and 40 CFR 60, Subpart J)

   b. NO_X and O_2 (ARM 17.8.749)

   c. CO and O_2 (ARM 17.8.749, ARM 17.8.342 and 40 CFR 63 Subpart UUU)

   d. Opacity (ARM 17.8.340 and 40 CFR 60 Subpart J, and ARM 17.8.342 and 40 CFR 63 Subpart UUU)

7. Calumet shall install, certify, calibrate, maintain and operate the above-mentioned Boiler #1 and Boiler #2 stack and FCCU CEMS in accordance with the requirements of 40 CFR 60.11, 60.13, and 60 Appendix A, and the applicable performance specification test of 40 CFR 60 Appendices B and F and 40 CFR 60, Subpart J. These CEMS are a means for demonstrating compliance with the relevant emission limits (ARM 17.8.749 and 40 CFR 60, Subpart J).

8. For both the gasoline truck loading rack and the gasoline railcar loading rack, Calumet shall install, calibrate, certify, operate and maintain a thermocouple with an associated recorder as a continuous parameter monitoring system (CPMS). A CPMS shall be located in each VCU firebox or in the ductwork immediately downstream from the firebox in a position before any substantial heat exchange occurs in accordance with 40 CFR 63.427, in order to demonstrate compliance with 40 CFR 63, Subpart R. Calumet shall operate the VCUs in a manner not to go below the operating parameter values established using the procedures in 40 CFR 63.425 (ARM 17.8.342 and 40 CFR 63 Subpart CC).

9. Calumet shall operate and maintain instrumentation for continuously monitoring the volumetric flow and sulfur content to the flare system in accordance with the requirements of 40 CFR 60 Subpart Ja (ARM 17.8.340 and 40 CFR 60 Subpart Ja).

10. The FCCU shall be tested for CO and SO_2 and the results submitted to DEQ in order to demonstrate compliance with the emission limits contained in Section II.C.13.c and d. The testing shall occur annually or according to another testing/monitoring schedule as may be approved by DEQ (ARM 17.8.105 and ARM 17.8.106).

12. All fuel combustion devices in the #2 Crude Unit shall be initially tested for NO_X and subject to the applicable performance testing requirements of 40 CFR 60, Subpart Ja (ARM 17.8.340 and ARM 17.8.749).

13. The owner or operator of each applicable fuel combustion device and flare subject to 40 CFR 60, Subpart Ja shall demonstrate initial compliance with the applicable emission limit in §60.102a according to the requirements of §60.8.

14. Calumet shall comply with all test methods and procedures as specified by 40 CFR 63.425(a) through (c), and 63.425(e) through (h). This shall apply to, but not be limited to, the gasoline and distillate truck loading rack, the gasoline railcar loading rack, the vapor processing systems, and all gasoline equipment.

15. The gasoline truck loading rack VCU shall be tested for total organic compounds and compliance demonstrated with the emission limitation contained in Section II.C.11 on an every 5-year basis or according to another testing/monitoring schedule as may be approved by DEQ. Calumet shall perform the test methods and procedures as specified in 40 CFR 63.425 (ARM 17.8.105 and 17.8.342).

16. The gasoline railcar loading rack VCU shall be initially tested for total organic compounds and compliance demonstrated with the emission limitation contained in Section II.C.12.a within 180 days of initial startup. Additional testing shall occur on an every 5-year basis or according to another testing/monitoring schedule as may be approved by DEQ. Calumet shall perform the test methods and procedures as specified in 40 CFR 63.425 (ARM 17.8.105 and 17.8.342).

17. The gasoline railcar loading VCU shall be initially tested for CO and NO_X, concurrently, and compliance demonstrated with the emission limitations contained in Section II.C.12.b and c within 180 days of initial startup (ARM 17.8.105).

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

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

20. Calumet shall conduct a Method 22 on the thermal catalytic oxidizer required by Section II.C.16 within 90 days of startup of the unit. No source test protocol need be submitted prior to the test, provided the observations are conducted and recorded as required by Method 22. A source test report shall be submitted to DEQ within 15 days of completion of the test. (ARM 17.8.749).

21. DEQ may require further testing (ARM 17.8.105).

F. Compliance Determination

1. Facility-wide Refinery:

   a. Compliance with the plant-wide SO_2 emission limitations contained in Section II.C.1.a shall be determined based on data taken from the refinery fuel gas H_2S monitoring systems required by 40 CFR 60, Subpart J or Ja, in conjunction with metered refinery fuel gas usage, data from the FCCU SO_2 CEMS, and the #1 and #2 Boiler SO_2 CEMS, and stack testing data (ARM 17.8.749).

   b. Compliance with the plant-wide CO emission limitations contained in Section II.C.1.b shall be determined based on data from the FCCU CO CEMS and emission factors developed from stack tests of the Boiler #1, Boiler #2, Boiler #3, FCCU, product loading VCUs, and any other stack tests conducted (ARM 17.8.749).

   c. By the 25th day of each month, Calumet shall calculate and record the monthly and rolling 12-month sum of NO_X emissions from each unit subject to the NO_X umbrella limitations for the previous month. Calumet shall also calculate and record, by the 25th of each month, the total monthly and rolling 12-month sum of emissions for the units combined for the previous 12 months (ARM 17.8.749).

   d. By the 25th day of each month, Calumet shall calculate and record the monthly and rolling 12-month sum of CO emissions from each unit subject to the CO umbrella limitations for the previous month. Calumet shall also calculate and record, by the 25th of each month, the total monthly and rolling 12-month sum of emissions for the units combined for the previous 12 months (ARM 17.8.749).

2. Boilers #1 and #2

   a. Compliance with Boilers #1 and #2 SO_2 emission limitations contained in Section II.C.3.a shall be based on the data from the SO_2/O_2 CEMS (May 2008 Administrative Order on Consent and ARM 17.8.749).

   b. In the event that the SO_2/O_2 CEMS or stack volumetric flow monitor is not operational, Calumet must (ARM 17.8.749):

      i. notify DEQ of the problem within 24 hours (by phone) followed by written notification within 7 days;

      ii. continue to monitor using the H_2S CEMS at the fuel gas drum (pre-combustion);

      iii. route all SWS overhead gas to the flare system caustic scrubber;

iv. repair and/or replace the SO_2/O_2 CEMS equipment and continue to monitor compliance as required in Section II.F; and

v. notify DEQ within 24-hours when the SO_2/O_2 CEMS is back on-line.

c. Compliance with the #1 and #2 Boiler CO emission limits contained in Section II.C.2 shall be determined through compliance source testing and by using the actual fuel burning rates and the emission factors developed from the most recent compliance source test (ARM 17.8.749).

3. Boiler #3

a. Compliance with the Boiler #3 refinery fuel gas H_2S limitations shall be based on the data from the H_2S CEMS at the fuel gas drum (pre-combustion) operated in compliance with 40 CFR 60 Subpart Ja (ARM 17.8.749).

b. Calumet shall monitor NO_X emissions from Boiler #3 in accordance with 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja, ARM 17.8.749).

c. Compliance with the Boiler #3 CO emission limits in Section II.C.3 shall be demonstrated through compliance source testing and by using the actual fuel burning rates and the emission factors developed from the most recent compliance source test (ARM 17.8.749).

4. HTU Heater (H-1701)

Compliance determinations for NO_X and CO emission limits for the HTU Heater (H-1701) shall be based upon source testing and actual fuel burning rates and emission factors developed from the most recent compliance source test.

5. Hydrogen Plant(s) - Reformer Heaters

a. Compliance determinations for NO_X and CO emission limits for Hydrogen Plant #1 reformer heater shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test.

6. Gasoline Truck Loading Rack VCU

Compliance determinations for VOC, NO_x and CO emission limits for the gasoline truck loading rack VCU shall be based upon the most recent compliance source test as well as compliance with the designated operating parameter value using the thermocouple and recorder.

7. Gasoline Railcar Loading Rack VCU

Compliance determinations for VOC, NO_X and CO emission limits for the gasoline railcar loading rack VCU shall be based upon the most recent compliance source test as well as compliance with the designated operating parameter value using the thermocouple and recorder.

8. FCCU

   Compliance determinations for the PM emission limit under Section II.C.12.a will be based on the annual source test conducted under Section II.E. Compliance determinations for CO, SO_2 and NO_X emission limits under Section II.C.13 will be based on the data from CEMS as well as the annual source test conducted under Section II.E.

9. #2 Crude Unit and MHC process heaters (H-2101, H-2102)

   Compliance monitoring with NSPS Ja NO_X and SO_2 emission limits for these heaters shall be conducted in accordance with monitoring and testing requirements of 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

10. Flare System (Primary Flare #1 and Secondary Flare #2)

    Calumet shall install, operate, calibrate, and maintain an instrument for continuously monitoring and recording the concentration by volume (dry basis) of H_2S in the fuel gases before being burned in any fuel combustion device or flare. The H_2S monitor shall be installed, operated, and maintained in accordance with Performance Specification 7 of Appendix B to Part 60 (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

11. Compliance with the opacity limitations shall be determined according to 40 CFR 60, Appendix A, and Method 9 Visual Determination of Opacity of Emissions from Stationary Sources.

12. Calumet shall determine, and submit to DEQ for concurrence, an empirically determined "k" factor to multiply conductivity (in micro-siemens per centimeter) of cooling tower water by to determine total dissolved solids of the cooling tower water. Such k factor shall be proposed within 3 months of finalization of MAQP #2161-31. Thereafter, Calumet shall test a representative grab sample of cooling water tower water for conductivity no less than once per calendar quarter utilizing Method 120.1 conductivity test procedures, as found for use under 40 CFR 136, or alternatively, at a more frequent interval and/or with different methods as may be proposed in writing by Calumet and approved in writing by DEQ. The results shall be recorded and compared to the conductivity that would represent the 1,500-ppm total dissolved solids limit in a log (ARM 17.8.749). Calumet shall maintain, on-site, documentation regarding the drift rate of drift eliminators maintained on each cooling tower (ARM 17.8.749).

G. Reporting and Recordkeeping Requirements

1. Plant-wide Refinery

   Calumet shall provide semiannual emission reports to demonstrate compliance with Section II.C.1.a using data required in Section II.F.1.a. The report shall include the following (ARM 17.8.749):

   a. Facility-wide SO_2 emission estimates for each month, including:

i. Refinery fuel gas: daily H_2S monitoring data and refinery fuel gas usage.

ii. SO_2 CEMS Data from FCCU, and Boiler #1 and #2, converted to daily mass emissions.

b. Compliance source test data used to update emission factors, conducted during the reporting period.

c. Monitoring downtime that occurred during the reporting period.

2. Boilers #1 and #2

Calumet shall provide semiannual emission reports to demonstrate compliance with Section II.C.2 using data required in Section II.F.2. The report shall include the following (ARM 17.8.749):

a. SO_2 emission estimates for #1 and #2 Boilers for each month, including:

i. Hourly SO_2 CEMS data for the reporting period.

ii. Fuel gas H_2S analyzer data for the reporting period.

b. NO_X emission estimates for each month. The NO_X emission rates shall be reported as an hourly average and a monthly total.

c. CO emission estimates for the #1 and #2 Boilers for each month. The CO emission rate shall be reported as an hourly average.

d. Compliance source test data used to update emission factors, conducted during the reporting period.

e. Calumet shall maintain records of daily fuel usage (in MMscf/yr) of the #1 and # 2 Boilers. The fuel usage shall be reported annually for each Boiler based on a 12-month total (ARM 17.8.749).

f. Monitoring downtime that occurred during the reporting period.

3. Boiler #3

Calumet shall provide semiannual emission reports to demonstrate compliance with Section II.C.3 using data required in Section II.F.3. The report shall include the following (ARM 17.8.749):

a. SO_2 emission estimates for the Boiler #3 for each month, including:

i. Fuel gas H_2S analyzer data for the reporting the data.

b. NO_X emission estimates for each month. The NO_X emission rates shall be reported as an hourly average.

c. CO emission estimates for the Boiler #3 for each month. The CO emission rate shall be reported as an hourly average.

d. Compliance source test data used to update emission factors conducted during the reporting period.

e. Monitoring downtime that occurred during the reporting period.

4. Gasoline Truck Loading Rack VCU

   Calumet shall comply with all recordkeeping and reporting requirements, as applicable, of 40 CFR 63.654 and the referenced provisions in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC).

5. Gasoline Railcar Loading Rack VCU

   Calumet shall comply with all recordkeeping and reporting requirements, as applicable, of 40 CFR 63.654 and the referenced provisions in 40 CFR 63, Subpart R (ARM 17.8.342 and 40 CFR 63, Subpart CC).

6. FCCU

   Calumet shall provide semiannual emission reports to demonstrate compliance with Section II.C.13 using data required in Section II.F.8. The report shall include the following (ARM 17.8.749):

   a. Emission estimates for NO_X, SO_2 and CO, for each month.

   b. Daily SO_2 CEMS data for the reporting period.

   c. Hourly NO_X and CO CEMS data for the reporting period.

   d. Operating times for the FCCU during the reporting period.

   e. Monitoring downtime that occurred during the reporting period.

7. All Emission Reports shall be submitted within 45 days following the end of the semiannual period (ARM 17.8.749).

8. Calumet shall maintain a file of all measurements from all CEMS and H_2S monitors, including, but not limited to: compliance data; performance testing measurements; all flow rate meter performance evaluations; all flow rate meter calibrations, checks, and audits. Adjustments and maintenance performed on these systems or devices shall be recorded in a permanent form suitable for inspection. The file shall be retained on site for at least 5 years following the date of such measurements and reports. Calumet shall supply these records to DEQ upon request (ARM 17.8.749).

9. Calumet shall report monthly and rolling 12-month sums for each unit under the NO_X and CO Umbrella limitations of Sections II.C.16 and II.C.17, on a semiannual basis. The report shall include monthly and rolling 12-month sums for each unit, and as a sum of all units (ARM 17.8.749).

H. Operational Reporting Requirements

1. Calumet shall supply DEQ with annual production information for all emission points, as required, by DEQ 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 DEQ by the date required in the Emission Inventory request. Information shall be in the units required by DEQ. 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. Calumet shall notify DEQ 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 DEQ, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change and must include information requested in ARM 17.8.745(l)(d) (ARM 17.8.745).

3. All records compiled in accordance with this permit must be maintained by Calumet 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 DEQ, and must be submitted to DEQ upon request (ARM 17.8.749).

I. Notification Requirements

1. Calumet shall provide DEQ with written notification of the following dates within the specified time periods (ARM 17.8.749):

   a. Pretest information forms must be completed and received by DEQ no later than 25 working days prior to any proposed test date, according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

   b. DEQ must be notified of any proposed test date 10 working days before that date according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

   c. DEQ must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitations or can be expected to last for a period greater than 4 hours (ARM 17.8.110).

SECTION III: General Conditions

A. Inspection – Calumet shall allow DEQ'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) and 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 the terms, conditions, and matters stated herein shall be deemed accepted if Calumet fails to appeal as indicated below.

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving Calumet 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 action as specified in Section 75-2-401, *et seq*., MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by DEQ's decision may request, within 15 days after DEQ 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 DEQ'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 DEQ'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, DEQ's decision on the application is final 16 days after DEQ'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 DEQ at the location of the source.

G. Permit Fee – Pursuant to Section 75-2-220, MCA, failure to pay the annual operation fee by Calumet may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

H. 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).

Summary of Attachments

Attachment 1	PORTABLE ELECTROCHEMICAL (EC) ANALYZER TESTING FOR NO_X AND CO UMBRELLA LIMIT MONITORING

ATTACHMENT 1

Portable Electrochemical (EC) Analyzer Testing for NO_X and CO Umbrella Limit Monitoring

Calumet shall submit a source testing protocol, intended to be applicable for 5 years from the acceptance date, regarding details of the portable testing plan. The following are guidelines which outline the minimum requirements to be met in such submittal.

Analyzer Apparatus

1. Use any measurement system that meets the performance and design specifications of this guidance. The sampling system should maintain the gas sample at conditions that will prevent condensation in the lines or when it contacts the EC cells. Some of the components of an appropriate measurement system are described below.

2. The sample probe and sample line should be made of glass, stainless steel or other non-reactive material and should be designed to prevent condensation.

3. The calibration assembly should introduce calibration gases at ambient pressure to the sample probe during calibration checks. The assembly should be designed such that only the calibration gases are processed and that the calibration gases flow through all the filters in the sampling line.

4. The moisture removal system should be used to remove condensate from the sample gas while maintaining minimal contact between the condensate and the sample gases.

5. Particulate filters should be utilized before the inlet of the EC analyzer to prevent accumulation of particulate material in the measurement system and to extend the useful life of the EC analyzer. All filters should be fabricated of materials that are non-reactive to the gases being sampled.

6. The sample pump should be a leak-free pump that will transport the sample gas to the system at a flow rate sufficient to minimize the response time of the measurement system. If upstream of the EC cells, the pump should be constructed of material that is non-reactive to the gases being sampled.

7. The sample flow rate should not vary by more than 10% throughout the calibration, testing, and drift check.

8. Interference gas scrubbers should be checked and replenished in accordance with the manufacturer's recommendations. EC analyzers should have a means to determine when the agent is depleted.

9. A data recorder should be used for recording the EC analyzer data.

EC Analyzer Calibration and Testing Specifications:

1. For purposes of testing for submission to DEQ, all combustion equipment shall be tested "as-found." No tuning or maintenance for the purpose of lowering tested emissions is allowed within 24 hours prior to testing.

2. Each EC analyzer should be certified by the manufacturer at least once per year unless waived by DEQ. Assemble the measurement system by following the manufacturer's recommended procedures for preparing and preconditioning the EC analyzer. Ensure the system has no leaks and verify that the gas-scrubbing agent is not depleted. When an EC cell is replaced, the EC analyzer should be re-calibrated.

3. Calibration of the EC analyzer should be done using certified calibration gases (EPA Protocol gases). Fresh air, free from ambient CO and NO_X, is permitted for O_2 calibration (20.9% O_2), and as a zero gas for CO and NO_X. Calibration gases for NO, NO_2, and CO should be chosen so that the concentration of the calibration gas is between 20% and 125% of the range of concentrations of the EC analyzer cell for each pollutant. Alternatively, calibration gases should not exceed 200% of the anticipated concentration expected from the emission unit being tested. If the measured concentration exceeds 125% of the span of the EC analyzer, at any time during the sampling run, that test run should be considered invalid. For NO_2 concentrations below 10% of the total NO_X concentration, NO_2 does not have to be measured directly and calibration of the EC analyzer for NO_2 is not required.

4. Inject each calibration gas into the EC analyzer and record the start time, response time, and concentrations. Gases should be injected through the entire sample handling system. All EC analyzer output responses should be recorded at least once per minute. The response time is the time it takes for the EC analyzer to get a steady response from a calibration gas after injecting the calibration gas into the measurement system. Actual measurements should not be averaged until the after the response time of the measurement system. After each calibration gas run, the EC analyzer should be refreshed with fresh air, free from CO, NO_X, and other pollutants. Repeat these steps for each calibration gas.

5. For the EC analyzer O_2 cell calibration, the minimum detectable limit should be 0.3%. For the EC analyzer NO_X and CO cells, the minimum detectable limit should be 2% of the calibration gas or 2 ppm whichever is less restrictive. If an invalid calibration is exhibited, corrective action should be taken, and the EC analyzer calibration check should be repeated until an acceptable EC analyzer performance is achieved.

6. Calculate the mean of the readings from the EC analyzer for each calibration gas. The average calculated EC analyzer response error for each calibration gas should not exceed ±5% of the calibration gas concentration. The maximum allowable deviation of any single reading, after the response time and prior to the refresh period, should not exceed ±2% of the average calculated EC analyzer response. For example: For a calibration gas with a concentration of 100 ppm, the calibration gas check should be considered valid only if the average of the measured concentrations for that calibration gas are within 5 ppm of 100 ppm, i.e., 95 to 105 ppm, and if the maximum deviation of any single measurement comprising that average is less than 2% or approximately 2 ppm.

7. During calibration an interference check should be performed. During the calibration check of a single gas species (e.g., NO & NO_2), record the response displayed by the other EC cells (i.e., CO & NO). Record the interference response for each EC cell to each calibration gas. The CO, NO, and NO_2 interference response should not exceed 5% of the calibration gas concentration. EC analyzers that have been verified for interference response using an interference scrubber are considered to be in compliance with this interference check specification when the interference scrubber is replenished per manufacturer's specifications.

The potential for interference from other flue gas constituents should be reviewed with the EC analyzer manufacturer based on site-specific data.

8. A post-test calibration check should be performed in the same manner as the pre-test calibration after each emissions unit test. If the post-test calibration checks do not meet the required specifications, all test data for that emissions unit should be considered null and void and re-calibration and re-testing should be conducted. To prevent loss of data, the drift of the analyzer should be determined after each measurement cycle. This should be done by performing a calibration check after each measurement cycle and determining the drift to ensure that it is still within the limit of ±5%. No changes to the sampling system or EC analyzer calibration should be made until all post-test calibration checks have been recorded. The difference (% Drift) between the pre-test calibration and the post-test calibration should not exceed 5% for each pollutant.

EMISSIONS MEASUREMENTS

1. Testing should be conducted by personnel trained in the use of the specific EC analyzer utilized for the testing. Samples of pollutant concentrations should be taken from sample ports in the stack or using a "Shepard's hook" from a location in the stack such that a representative concentration is measured and bias (e.g., air leakage at weep holes) is prevented. A single sampling location near the center of the duct may be selected.

2. Prior to sample collection, ensure that the pre-test calibration has been performed. Zero the EC analyzer with fresh air, free from ambient CO and NO_X or other combustion gases. Each test for an emission unit should consist of at least three 10-minute measurement cycles. Position the probe at the sampling point and begin the measurement cycle at the same flow rate used during the calibration check. Measurements should not be recorded and averaged until the measurement system response time has passed. The EC analyzer should be "refreshed," the analyzer drift should be determined, and the moisture collection system emptied after each sampling cycle. Use the measurement data to calculate the mean effluent concentration. The Data recorder should record a reading at least every 60 seconds. Record the average gas sample concentration for each pollutant from the cycle on a form similar to the one provided.

3. Conduct the post-test calibration check after testing of each emission unit. If the sampling system is disassembled or if the EC analyzer calibration is adjusted, the EC analyzer should be recalibrated before conducting the next emission unit test.

4. The emissions testing should produce at least three sets of concentration data for each pollutant of concern. Results from each test represent a "quasi steady-state" measurement of pollutant concentration and the measured pollutant concentrations should be calculated as the mean gas concentration using the emissions data collected during the three test runs. Data from additional tests may be included in the calculation so long as other operational parameters remain relatively unchanged. To maintain consistency, the run length should be the same for all runs and all units.

5. The measured pollutant concentrations should then be corrected to give actual values using the pre-test calibration and post-test calibration results. The following equation should be used.

$$C_{ACTUAL} := \left(\boxed{C_{MEAS}} - C_{CZ}\right) \cdot \frac{\left(C_{CAL} - C_{CZ}\right)}{\left(C_{CM} - C_{CZ}\right)}$$

Where:

C_{ACTUAL} = actual pollutant concentration, ppmdv

C_{MEAS} = measured pollutant concentration, ppmdv

C_{CAL} = concentration of the calibration gas, ppmv

C_{CZ} = average of pre-test and post-test calibration zero checks, ppmdv

C_{CM} = average of pre-test and post-test measured concentrations of the calibration gas measurement checks, ppmdv

<u>Operational Parameter Measurements</u>:

1. During the emissions testing of the emission unit, the following operational parameters should be measured or determined:

   a. % Firing Rate
   b. Fuel Btu content
   c. Fuel Consumption

2. Sampling of the fuel, that is representative of the fuel combusted in the emission unit, should be performed. The fuel sampling should be conducted within a 24-hour period of the testing. The sample should be taken from the inlet gas line, downstream from any inlet separator, using a manifold to remove entrained liquids from the sample and probe to collect the sample from the center of the gas line.

3. The stack velocity or flow shall be measured or determined using one of the following methods:

   a. EPA Reference Method 19
   b. A method as approved by DEQ, such as Method 2

Calculations and Requirements for a Valid Test Run:

Oxygen Based F Factor, Dry Basis

Use Method 19 equation 19-1.

$E = C_d F_d * (20.9/(20.9 - \%O_2 dry))$

Fd Calculation:

Use Method 19 Equation 19-13.

$$F_d = \frac{K(K_{hd}\%H + K_c\%C + K_s\%S + K_n\%N - K_o\%O)}{GCV} \qquad \text{Eq. 19-13}$$

Calibration Error:

Calibration Error = (Analyzer Response – Calibration Gas Concentration) / (Calibration Gas Concentration) * 100%. This value must be < 5% for a valid run.

% Interference

% Interference = Analyzer Response/Calibration Gas Concentration * 100%. This value must be <5% for a valid run.

% Drift

% Drift = (Post Test Analyzer Response – Pre-Test Analyzer Response)/(Pre Test Analyzer Response) * 100%. This value must be less than 5% for a valid test run.

Training:

Any persons performing the portable analyzer testing should be trained in the use of that portable analyzer and the associated concepts and principles of the emissions measurements and associated calculations.

Reporting

1. Use the following form when reporting results. This form is available electronically in Excel format and is available upon request, and is required to be reported on a semiannual basis.

2. Testing results that show emissions factors which are 10% or more higher than established during the last source test for the emitting unit, shall be reported within 2 weeks of the test. Such results will trigger the need for a full source test.

Calumet Portable Analyzer Emission Check
Monthly Monitoring Report

Tester Name				Ambient Temperature (°F)	
Tester Signature				Barometric Pressure (" Hg)	
Tester Title and Affiliation:				Date	

Emitting Unit Name as indicated in MAQP					
Fuel Factor (Fd) (dscf/MMBtu, as determined via Method 19 ultimate analysis on fuel burned on the testing date)					
Time Start					
Time Stop					
Check Zero NOx					
Check Zero CO					
Check Zero O2					
Check Span NOx (ppm)					
Check Span CO (ppm)					
Check Span O2 (ppm)					
Measured NOx (ppm)					
Measured CO (ppm)					
% O2					
Flue Gas Temp. (°F)					
Moisture (%)					
Check Zero NOx					
Check Zero CO					
Check Zero O2					
Check Span NOx (ppm)					
Check Span CO (ppm)					
Check Span O2 (ppm)					
NOx Calibration Error (%)					
NOx Interference (%)					
NOx Drift (%)					
CO Calibration Error (%)					
CO Interference (%)					
CO Drift (%)					
average % firing rate					
Maximum Rated Design Capacity (MMBtu/hr)					
Estimated lb/MMBtu emissions rate:					

notes: See Appendix 2 of the MAQP for equations, testing requirements, QA/QC requirements, and etc.

Montana Air Quality Permit (MAQP) Analysis
Calumet Montana Refining, LLC
MAQP #2161-40

I. Introduction/Process Description

Calumet Montana Refining, LLC (Calumet) operates a petroleum refinery located at the NE ¼ of Section 1, Township 20 North, Range 3 East, in Cascade County, Montana. The refinery is located along the Missouri River in Great Falls, Montana.

A. Permitted Equipment

The major permitted equipment at Calumet includes the following emission sources:

#1 Crude Unit, including
- Crude Heater H-0101 (30 million British thermal units per hour (MMBtu/hr))
- Vacuum Heater H-0102 (7 MMBtu/hr)

#2 Crude Unit, including
- Crude Heater H-2101 (71 MMBtu/hr)
- Vacuum Heater H-2102 (27 MMBtu/hr)
- Off-gas compressor (a primary compressor and a backup compressor) (NEW)

Catalytic Poly Unit

Fluidized Catalytic Cracking Unit (FCCU), including
- FCCU Preheater H-0302 (8.9 MMBtu/hr)
- FCCU Catalyst Regenerator

Catalytic Reformer and Naphtha Unit, including
- Reformer Heater H-0403 (24.2 MMBtu/hr, HHV)
- Naphtha HDS Heater H-0402a (13.6 MMBtu/hr, HHV)
- Naphtha Splitter Reboiler H-0405 (9.9 MMBtu/hr, HHV)
- Naphtha Hydrodesulfurization (HDS) Unit
- Kerosene HDS Unit

Alkylation Unit, including
- Deisobutanizer reboiler (28 MMBtu/hr)

Hydrogen Plants, including
- Hydrogen Plant #1 Reformer Heater H-1801 (23.8 MMBtu/hr)
- Hydrogen Plant #2 Reformer Heater H-2815 (80 MMBtu/hr)

Hydrotreater Unit (HTU), including

- Kerosene Heater
- HTU Heater H-1701 (22.5 MMBtu/hr, HHV)

Sodium Hydrosulfide (NaHS) Unit

Polymer-Modified Asphalt (PMA) Unit, including

- D-1901 – wetting tank (New larger tank added in MAQP #2161-35)
- RT-1901 – reactor tank
- Tank 130: 1,007 bbl for PMA Preparation
- Tank 132: 1,007 bbl for PMA Preparation
- Tank 133: 1,007 bbl for PMA Preparation
- Tank D-1906: 55 bbl Hot Oil Expansion Tank
- Tank D-1907: 72 bbl Crosslinking Tank
- Prilled Sulfur Handling Operations

Product Loading, including

- Truck Loading with Vapor Combustion Unit (VCU)
- Railcar Loading with VCU
- Railcar Loading (diesel and asphalt)

Utilities

- Boilers #1 & #2 with maximum rated capacity of 25 MMBtu/hr each
- Boiler #3 with maximum capacity of 60.5 MMBtu/hr
- Tank D-1908: 55 bbl Hot Oil Expansion Tank
- Wastewater
  Surge Tank T-143, 18,000 bbl external floating roof
  Surge Tank T-145, 37,000 bbl external floating roof
  Aeration Tank TK-146
  Slop Oil Tank 144, 600 bbl
  Slop Oil Tank 144B, 300 bbl
  Slop Oil Tank 186, 600 bbl each
  API Separator
  DAF Unit (Existing and New DAF unit in series)
  Drains
- North and South Cooling Towers

Storage Tanks, including:
Tank 1: 152 bbl, Fixed Roof in Jet Fuel Additive service
Tank 2: 800 bbl Pressure Vessel in Propane service
Tank 3: 2,000 bbl Pressure Vessel in Isobutane service
Tank 4: 600 bbl Pressure Vessel in Butane service
Tank 5: 600 bbl Pressure Vessel in Isobutane service
Tank 10: 375 bbl Fixed Roof tank in Transmix service
Tank 14: 1,400 bbl Pressure Vessel in Isobutane service
Tank 15: 1,400 bbl Pressure Vessel in Butane service

Tank 47: 20,500 bbl Fixed Roof in Middle Distillates service
Tank 48: 20,500 bbl Fixed Roof in Middle Distillates service
Tank 49: 20,500 bbl Fixed Roof in Middle Distillates service

Tank 51: 21,000 bbl Fixed Roof in Kerosene / Jet Fuel service
Tank 52: 19,000 bbl External Floating Roof in Gasoline service
Tank 55: 3,022 bbl in Asphalt Service

Tank 58: 20,983 bbl Fixed Roof in Middle Distillates service
Tank 100: 1,100 bbl Fixed Roof in #5 Fuel Oil or NaHS service
Tank 101: 1,100 bbl Fixed Roof in #5 Fuel Oil or NaHS service

Tank 118: 2,000 bbl Fixed Roof in Asphalt Emulsion service
Tank 119: 2,000 bbl Fixed Roof in Asphalt Emulsion service
Tank 120: 2,200 bbl Fixed Roof in Asphalt Emulsion service
Tank 121: 2,200 bbl Fixed Roof in Asphalt Emulsion service
Tank 122: 21,900 bbl External Floating Roof in Gasoline service
Tank 123: 21,900 bbl External Floating Roof in Gasoline service
Tank 124: 21,500 bbl External Floating Roof in Naphtha service
Tank 125: 38,500 bbl Fixed Roof in Heavy Liquids Service
Tank 126: 29,500 bbl External Floating Roof in Gasoline service
Tank 127: 21,500 bbl External Floating Roof in Gasoline service

Tank 137: Fixed Roof in Asphalt Storage service
Tank 138: Fixed Roof in Asphalt Storage service
Tank 139: Fixed Roof in Asphalt Storage service

Tank 150: 30,100 bbl Fixed Roof in Raw Kerosene service
Tank 170: 10,200 bbl Fixed Roof in Distillate service
Tank 171: 10,200 bbl Fixed Roof in Distillate service
Tank 175: 400 bbl Fixed Roof in Ethanol service
Tank 176: 5,000 bbl Internal Floating Roof in Ethanol service
Tank 201: 69,700 bbl External Floating Roof in Crude Oil service
Tank 202: 69,700 bbl External Floating Roof in Crude Oil service

Tanks Added Under the *de minimis* action known as the Canola Oil Project:

Three tanks of 21,000 gallons each for storage of approximately 29,000 gallons of Canola oil for storage on-site for up to 8 months.

Tanks Added Under the Refinery Reconfiguration Project:

Tank 58: 20,983 bbl Fixed Roof in Middle Distillates service

Stationary Internal Combustion Engines:

GEN1: 400 hp diesel fired Emergency Generator
AC1: 540 hp diesel fired Emergency Air Compressor Engine
WP1: 165 hp, diesel fired Emergency Storm Water Pump

WP2: 240 hp, diesel fired Tank 54 Emergency Fire Water Pump
WP3: 300 hp, diesel fired Tank 24 Emergency Fire Water Pump
WP4: 300 hp, diesel fired Tank 146 Emergency Fire Water Pump

Electric Catalytic Thermal Oxidizer for the AOC-16 Remediation Project

B. Source Description

Petroleum refining has been conducted at this site since the early 1920's. Calumet converts crude oil into a variety of petroleum products, including gasoline, diesel fuel, jet fuel, naphtha, asphalt, and NaHS.

C. Permit History

On December 2, 1985, the Montana Department of Health and Environmental Sciences and Montana Refining Company (MRC) signed a stipulation requiring MRC to obtain an air quality permit and stipulated that a permit emission limitation of 4,700 tons per year (TPY) carbon monoxide (CO) would constitute compliance with ambient CO standards. MRC submitted this permit application with the intentions of permitting its existing refining operations, including all equipment not already permitted.

On October 20, 1985, MRC was granted a general permit for their petroleum refinery and major refinery equipment located in Great Falls, Cascade County, Montana. The application was given **MAQP #2161**.

The first alteration to their original permit was given **MAQP #2161-A** and was issued on May 31, 1989. This alteration involved the addition of a deisobutanizer reboiler.

The second alteration was given **MAQP #2161-A1** and was issued on March 12, 1990. This project involved the installation of one 30,000-barrel gasoline storage tank and one 40,000-barrel crude oil storage tank at the present facility. Both tanks were installed with external floating roof control.

The third alteration was given **MAQP #2161-A3** and was issued on December 18, 1990. This alteration consisted of the installation of a Hydrofluoric (HF) Acid Alkylation Unit, internal floating roofs at existing storage tanks, which had fixed roofs, and a safety flare.

The fourth alteration was given **MAQP #2161-04** and was issued on June 16, 1992. This alteration consisted of the installation of a NaHS unit at the existing Great Falls Refinery.

The NaHS unit receives refinery fuel gas (540,000 standard cubic foot per day (scf/day) maximum rated capacity) containing hydrogen sulfide (H_2S) and reacts with a sodium hydroxide caustic solution to remove virtually 100% of the H_2S by converting it to NaHS, a saleable product.

The resultant sweet fuel gas is burned, as before, in other process heaters. However, since the fuel gas contains virtually no H_2S, sulfur dioxide (SO_2) emissions from the process heaters, assuming no other changes, were decreased by nearly 60%. There was no decrease in permitted SO_2 emissions from this permit because the refinery wanted to retain the existing permitted SO_2 emission limitations, so it could charge less expensive, higher sulfur crude oil.

In the basic process, off-gases from product desulfurizing processes (fuel gases) are contacted with a caustic solution in a gas contractor. The resultant reaction solution is continually circulated until the caustic solution is essentially used up; NaHS product is then sent to storage. Make-up caustic is added to the process as required. The process requires a gas contractor, process heat exchanger, circulation pump, storage tanks for fresh caustic and NaHS product, 12 pipeline valves, 4 open-ended valves, 21 flanges, and other process control equipment.

The only process emissions are fugitive Volatile Organic Compounds (VOC) from equipment (valves and flanges) in fuel gas stream service. To estimate unit VOC emissions, emission factors developed by the Environmental Protection Agency (EPA) for equipment in gas vapor service with measured emissions from 0 to 1,000 parts per million (ppm) are used. With an aggressive monitoring and maintenance program, fugitive VOC emissions from valves and flanges are within this 0 to 1,000-ppm range. Total annual fugitive VOC emissions from the NaHS units are estimated to be 20 pounds per year.

The tank that is to be used to store NaHS product was in jet fuel service. When taken out of jet fuel service, this tank (#35) is no longer a source of VOC emissions; the reduction in VOC emissions will be 2,270 pounds per year (PPY). Considering the 2,270-PPY decrease due to tank #35 service change, the refinery realized a net decrease in annual VOC emissions of 2,250 PPY or 1.1 TPY.

The fifth alteration was given **MAQP #2161-05** and was issued on October 15, 1992. This permit alteration was for the construction and operation of two 20,000-barrel capacity aboveground storage tanks at its Great Falls Refinery. The new tanks contain heavy naphtha (#127) and raw diesel (#128).

Each tank was constructed of metal sections welded together that rest on a concrete ring wall foundation. External floating roofs with dual seals are installed on each tank for VOC control.

On April 6, 1993, MRC was granted **MAQP # 2161-06** to construct and operate a HDS unit and hydrogen plant. This sixth alteration was required to go through New Source Review (NSR) - Prevention of Significant Deterioration (PSD) review for Oxides of Nitrogen (NO_X) and was deemed complete on February 22, 1993. The HDS project was designed to process 5,000 barrels per day (BPD) of diesel/gas oil and to reduce the sulfur content to 0.05 weight percent. The reduction of sulfur in diesel fuel and gasoline were mandated by the 1990 Clean Air Act Amendments and were accomplished by October 1993, and 1995, respectively. The desulfurizer unit operated by MRC was limited in size and throughput capacity to approximately 1,400 barrels per day.

The HDS project consisted of an HDS process unit and heater, hydrogen plant with reformer heater, and the removal of storage tanks #40 through #43. Tanks #40 and #41, which processed gas oil, were discontinued. Tanks #42 and #43 that process raw diesel were also discontinued. Tanks #44 and #111 were changed to gas oil use and Tank #45 which serviced JP-4 was changed to gas oil use.

On July 28, 1993, **MAQP #2161-07**, a modification to MRC's MAQP #2161-06, was issued to change the emission control requirements of the Section titled "Pressure Vessels."

In a system where the valves relieve to atmosphere, rupture discs can prevent emissions in the event of relief valve leakage. In HF systems, they can provide some protection from acid corrosion on the relief valve and acid salt formation. Except where HF acid is present, rupture discs do not provide any additional protection, nor do they prevent any release of air contaminates in a closed relief system.

In heavy liquid service, rupture discs can be safety hazards by partial failure or leaking and changing, over time, the differential pressure required providing vessel protection. Therefore, only pressure vessels in HF Acid service shall be equipped with rupture discs upstream of the relief valves and all except storage tanks shall be vented to the flare system.

Also, the allowable particulate emission limitation for MRC's FCCU was corrected to reflect the maximum allowable emissions based on the process weight rule (Administrative Rules of Montana (ARM) 17.8.310). The maximum allowable emissions were calculated to be 234.53 TPY using a catalyst circulation rate of 125 tons per hour (TPH).

MRC requested a permit modification, **MAQP #2161-08**, to remove the alkylation unit and tanks #127 and #128 from New Source Performance Standards (NSPS) status because they were erroneously classified as affected facilities under NSPS when originally permitted. This request for modification was submitted on August 11, 1993, and issued on January 6, 1994.

When MRC applied for the preconstruction permit to build the HF Alkylation Unit in 1990, it was presumed, since this unit was new to MRC, it automatically fell under NSPS as new construction. Subsequently, it has been determined that if a source is moved as a unit from a location where operation occurred (Garden City, Kansas) to another location, it must meet the definition of reconstruction or modification in order to trigger NSPS applicability.

The alkylation plant was originally constructed in Garden City, Kansas during 1959 - 1960 and moved, in its entirety, to Great Falls and installed. Since the unit was originally constructed before the NSPS-affected date of January 5, 1981, it does not meet the criteria for construction date of a new source under 40 Code of Federal Regulations (CFR), Subpart GGG or Subpart QQQ.

The project did not meet the criteria under reconstruction because no capital equipment was replaced when the unit was relocated. The replacement work performed, as the unit was moved, amounted to pump seals, valve packing, bearings, small amounts of corroded piping, and some heat exchanger tubes and bundles, all of which are done routinely as maintenance. The VOC emitters, such as valve packing and pump seals, were upgraded to meet Best Available Control Technology (BACT).

Along the same line, tanks #127 and #128 were originally constructed at Cody, Wyoming in 1960 and relocated to Great Falls in 1993. The only change was the modification of the roof seals to double seals to meet BACT. This cost of modification was a total of $15,000 for both tanks as compared to more than $500,000 if two new tanks were to be built.

Also, on October 28, 1993, MRC submitted a permit application to alter the existing permit. This modification and alteration of the existing permits were assigned MAQP #2161-08. MRC proposed to construct and operate a 3,500 barrel-per-day asphalt polymerization unit. The unit enabled MRC to produce a polymerized asphalt product that would meet future federal specifications for road asphalt, as well as supply polymerized asphalt to customers that wished to use the product.

The proposed unit consisted of two circuits: the asphalt circuit and the hot oil circuit. In the asphalt circuit, polymerization occurs in a 1,000-barrel steel, vented mix tank. Product blending and storage occurs in 3 steel, vented 1,000-barrel tanks identified as A, B, and C. Existing Tanks #55 and #56 (3,000 barrels each) remained in asphalt service and are used for storage. In addition to the above equipment, the asphalt circuit also consisted of 4 pumps and approximately 47 standard valves. All the above equipment became part of the asphalt service and, except for Tanks #55 and #56, was new.

To maintain the asphalt at the optimum temperature in the storage and blending tanks, a hot circuit was utilized. Hot oil (heavy fuel oil) was heated in an existing permitted process heater (Tank #56 heater) and circulated through coils in the process tankage. No change in the method of operation of the heater was anticipated. A steel vented hot-oil storage/supply tank was utilized to maintain the required amount of hot oil in the unit. In addition to the process heater and storage/supply tank, the hot-oil circuit consisted of one pump and approximately 56 standard valves. The above equipment was used in hot-oil service and, except for the heater, was new.

An annual emission increase of 7.3 TPY of VOC was expected due to operation of the unit. It was anticipated that the unit would be operated only 6 months of the year. The VOC emissions resulted from the vented hot-oil tank and the valves and pump in hot-oil service.

MAQP #2161-09 was issued on September 6, 1994, and included a change in the method of heating three previously permitted polymer modified asphalt tanks. As previously permitted, these tanks were heated utilizing circulating hot oil. The tanks were heated individually using natural gas fired fire-tube heaters. The use of natural gas eliminated the hot-oil circuit, including the hot-oil storage tank, entirely.

Since the initial permit application for the modified asphalt unit, several small design changes occurred involving the addition of a new 800-gallon wetting tank for asphalt service. An output line from existing Tank #69 (Tall Oil) was also added. This output line added approximately 12 new valves and one new pump, all in Tall Oil service, to the unit. All other valves and pumps were designated to be in asphalt service.

All VOC emissions from equipment and tanks in asphalt service were assumed to be negligible, since asphalt has negligible vapor pressure at the working temperatures seen in the unit.

MAQP #2161-10, for the installation of an additional boiler (Boiler #3) to provide steam for the facility, was never issued as a final permit. On May 28, 1997, the Department of Environmental Quality (DEQ) – Air Resources Management Bureau received a letter requesting the withdrawal of the permit application and the withdrawal was granted to MRC. A summary of this permitting action is included in the analysis for MAQP #2161-11.

MAQP #2161-11 was issued on January 23, 1998, for the installation of a vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAP) resulting from the loading of gasoline. This was done in order to comply with the gasoline loading rack provisions of 40 CFR 63, Subpart CC - National Emission Standards (NES) for Petroleum Refineries. A VCU was added to the truck loading rack. The gasoline vapors are collected from the trucks during loading then routed to an enclosed flare where combustion occurs. The result of this project was an overall reduction in the amount of VOC and HAPs emitted, and a slight increase in CO and NO_x emissions.

Because MRC's bulk gasoline and distillate truck loading rack VCU was defined as an incinerator under Montana Code Annotated (MCA) 75-2-215, 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. MRC and DEQ identified the following HAPs from the flare that was used in the health risk assessment. These constituents are typical components of MRC's gasoline.

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

The reference concentrations for Benzene, Toluene, Ethyl Benzene, and Hexane were obtained from EPA's IRIS database. The risk information for the remaining HAPs was contained in the January 1992 CAPCOA Risk Assessment Guidelines. The ISCT3 modeling performed by MRC for HAPs identified above demonstrated compliance with the negligible risk requirement.

MRC requested, via a letter dated August 13, 1997, changes to administratively and technically correct MAQP #2161-09. These changes were necessary as a result of the withdrawal of MAQP #2161-10. The changes included correctly stating opacity limits relating to asphalt storage tanks, removing references to procedural rules, changing monitoring requirements for the HTU Sour Water Stripper (SWS) and changing performance specifications for the continuous H_2S monitoring system.

DEQ issued Draft Modification #2161-11 on November 6, 1997, to address the permit changes that were requested by MRC. DEQ received comments on November 13, 1997, from MRC and later met on November 17, 1997, to discuss the draft modification. Because MRC had applied for a permit alteration on October 21, 1997, for the loading rack VCU, the draft modification was addressed in the permit alteration request.

DEQ issued Preliminary Determination #2161-11 on November 26, 1997. DEQ received comments from MRC on December 4, 1997, December 10, 1997, December 15, 1997, and December 30, 1997. DEQ responded to these comments via faxes on December 8, 1997, December 11, 1997, and December 16, 1997. On December 23, 1997, DEQ was prepared to issue a Department Decision, but MRC requested, via telephone, that the decision not be issued until after the holidays. The decision was required to be issued by January 8, 1998, to meet the mandated time frames for issuing a Department Decision.

MAQP #2161-12 was not issued. MRC applied for a modification on February 18, 1998, and this action was given #2161-12. On February 27, 1998, DEQ notified MRC that the permitting actions requested would require an alteration and that a complete preconstruction permit application would be required.

MAQP #2161-13 placed enforceable emission limits on the facility, both plant-wide and the #1 and #2 boilers. The emission limits showed, through the use of EPA-approved models, to protect the National Ambient Air Quality Standards (NAAQS) for SO_2.

The continuous gas flowmeters installed on the vacuum heater and the crude heater were placed in the permit. Also, the #1 and #2 boiler limits were updated to allow MRC more flexibility in their operations. The limits were originally placed on the boilers to keep MRC below the PSD permitting threshold. The new limits-maintained MRC's status below the PSD permitting threshold.

The monitoring location was identified in Attachment 1 Ambient Air Monitoring Plan. The current location was determined to be inappropriate after reviewing the modeling analysis, and the new location was approximately 1.2 km from its present location. The monitoring location was chosen based on the modeling analysis that was submitted and is required to provide monitored confirmation of compliance with the Montana SO_2 Standards.

The method numbers for examination of water and wastewater were updated. The conditions in MAQP #2161-13 were incorporated into the Operating Permit and the compliance demonstration methodology for those conditions was evaluated at the time of the Operating Permit's issuance. MAQP #2161-13 replaced MAQP #2161-11.

On August 6, 2001, DEQ issued **MAQP #2161-14** for the installation and operation of five 1600-kilowatt (kW) diesel-powered, temporary generators. These generators were necessary because of the current high cost of electricity. The generators would only operate for the length of time necessary for MRC to acquire a permanent, more economical, supply of power. Further, the generators are limited to a maximum operating period of 2 years.

Because these generators would only be used when commercial power is cost prohibitive, the amount of emissions expected during actual operation is minor. In addition, because the permit limits the operation of these generators to a time period of less than 2-years, the installation and operation qualifies as a "temporary source" under the PSD permitting program. Therefore, the proposed project does not require compliance with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, DEQ requires compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 will be ensured. Finally, MRC is responsible for complying with all applicable ambient air quality standards. MAQP #2161-14 replaced MAQP #2161-13.

On August 17, 2002, DEQ issued **MAQP #2161-15** to eliminate the summer boiler SO_2 emission limits (both the plant-wide and 24-hour average) and redefine the winter limits as year-round limits. The seasonal limits were originally placed in the permit to allow MRC more flexibility when operating the boilers. Both the winter and summer scenarios were supported by ambient air quality modeling performed prior to MAQP #2161-13 being issued. The winter limit being redefined as a year-round limit does not represent an increase in SO_2 emissions from the boilers or any other emitting point. In addition, DEQ removed requirements to determine and report NO_X emissions both from the crude heater (due to the old SWS) and refinery wide, as these sources are not subject to NO_X emissions limitations. The requirements appeared to have been inadvertently applied through an administrative error. MRC already provides refinery-wide NO_X emissions as part of its annual Emission Inventory submission to DEQ. MAQP #2161-15 replaced MAQP #2161-14.

On March 19, 2003, DEQ issued **MAQP #2161-16** to include certain limits and standards associated with the Consent Decree lodged on December 20, 2001. In addition, the permit was updated with new rule references under ARM 17.8, Subchapter 7. MAQP #2161-16 replaced MAQP #2161-15.

DEQ received a request to modify MAQP #2161-16 on July 10, 2003, to change the emission testing schedule for the gasoline truck loading vapor combustion unit to be consistent with MRC's current operating permit. MRC also requested DEQ clarify the 7,000-BPD limit of crude charge (referenced in MRC's Title V Operating Permit) is no longer valid. Should MRC's normal processing exceed 7,000-BPD, MRC would be required to comply with ARM 17.8.324, as applicable. In a letter received by DEQ on September 30, 2003, MRC also requested to add three new asphalt tanks with associated natural gas heaters. The emissions from the three tanks met the requirements of the de minimis rule and were added to the permit. The permit action updated the permit to reflect the changes. **MAQP #2161-17** replaced MAQP #2161-16.

On May 14, 2004, DEQ received a letter from MRC requesting changes to MAQP #2161-17. The proposed change includes adding the ability to burn sweet gas in heaters at the HF Alkylation Unit, and at Tanks 102, 135, 137, 138, and 139. The sweet gas will have a H_2S limit equivalent to the 40 CFR Part 60, Standards of Performance for NSPS, Subpart J limit of 0.10 grains per dry standard cubic foot (gr/dscf) H_2S. The continuous refinery fuel gas monitoring system for H_2S installed on the fuel gas system that supplies the heaters would be used to determine compliance with the limit. Since the emissions from switching the fuel to sweet gas were less than the de minimis threshold, DEQ added the fuel switch. The permit action updated the permit to reflect these changes. **MAQP #2161-18** replaced MAQP #2161-17.

On May 17, 2007, DEQ received an application from MRC for the installation of a railcar product loading rack controlled by a John Zink VCU. On June 19, 2007, MRC clarified that gasoline and naphtha were the only products that will go through the new railcar loading rack, and that other liquid products already loaded into railcars (diesel, jet fuel, etc.) would not be affected.

The gasoline railcar loading rack is subject to 40 CFR 63, Subpart CC, which requires MRC to comply with specific bulk loading requirements in 40 CFR 63, Subpart R. Subpart R restricts the operation of the railcar loading system to less than 10 milligrams (mg) of VOC per liter of gasoline loaded and requires the operation of a continuous monitor downstream from the firebox. Furthermore, the gasoline and naphtha railcars are considered as 'gasoline cargo tanks' and are required to comply with the leak detection testing requirements. Lastly, 40 CFR 63, Subpart CC requires MRC to comply with 40 CFR 60, Subpart VV to minimize fugitive equipment leaks.

Other new applicable regulations were added, including 40 CFR 63, Subpart UUU, Subpart EEEE, and Subpart DDDDD. Consent Decree #CIV-01-1422LH requirements, entered March 5, 2002 (Consent Decree), were included, such as the new requirements to comply with 40 CFR 60, Subpart J limits for refinery fuel gas and SWS overhead gas. Other changes completed in this permit action were adding FCCU uncorrected CO emissions from 40 CFR 63, Subpart UUU, and SO_2 and NO_X emission limits resulting from the Consent Decree; and revising the permit to reflect the operation of a continuous H_2S fuel gas meter and requirement to comply with 40 CFR 60, Subpart J. **MAQP #2161-19** replaced MAQP #2161-18.

On October 15, 2007, DEQ received a letter from MRC requesting a correction to MAQP #2161-19, to remove the restrictions on the type of fuel used in specific asphalt tank heaters, which was added erroneously during the previous permitting action. In addition, the MAQP was updated to reflect the fact that requirements under 40 CFR 63, Subpart DDDDD are now "state-only" since the federal rule was vacated in Federal Court on July 30, 2007. **MAQP #2161-20** replaced MAQP #2161-19.

On June 9, 2008, DEQ received a letter from MRC requesting an amendment to MAQP #2161-20, to modify the restrictions on Storage Tank #8. This request was a follow-up to a de minimis request received by DEQ on April 21, 2008, where MRC proposed to change the operation of Storage Tank #8 from NaHS to naphtha. DEQ reviewed this de minimis request and determined that MAQP #2161-20 must first be amended as described in ARM 17.8.745(2) and ARM 17.8.764 before this change would be allowed. Although the potential emissions increase for this project is less than the de minimis threshold, the proposal would have violated a condition of MRC's current permit. Specifically, the MAQP states, "Storage tanks #8, #9, #50, #55, #56, #69 #102, #110, #112, #130, #132, #133, and #135 shall be used for asphalt, modified asphalt, or tall oil service (ARM 17.8.749)." This permit has been amended to allow the proposed change in operation of Storage Tank #8.

On July 2, 2008, DEQ received another letter from MRC requesting an administrative amendment to MAQP #2161-20 to include certain conditions specified in the Administrative Order on Consent (AOC) that MRC entered into with DEQ on May 13, 2008. The AOC requires MRC to install and operate a SO_2 and Oxygen (O_2) continuous emission monitor system (CEMS) on the stack for the #1 and #2 Boilers. This SO_2/O_2 CEMS is to be used as the primary analytical instrument to determine compliance with state and federal SO_2 requirements. The AOC requires MRC to request that these conditions be included in the MAQP as enforceable permit conditions.

In addition, MRC requested that the permit be amended to allow certain de minimis changes related to the Diesel/Gas Oil HDS heater and three PMA tank heaters. Specifically, MRC requested that refinery fuel gas, in addition to natural gas, be allowed to be burned in these heaters. The current permit requires that the Diesel/Gas Oil HDS heater and the three PMA tank heaters be fired only with natural gas. This requirement is based on BACT. For the Diesel/Gas Oil HDS heater, the BACT analysis requires that low sulfur fuel be used. Since the refinery fuel gas is also a low sulfur fuel meeting 40 CFR 60, Subpart J requirements of 160 ppm H_2S, DEQ determined that the proposed change does not violate any applicable rule and therefore, can be allowed through an administrative amendment as specified in ARM 17.8.745(2) and ARM 17.8.764. For the three PMA tank heaters, however, the BACT analysis specifically requires that these heaters be fired with natural gas for control of NO_x emissions. Therefore, DEQ determined that the proposed three PMA tank heaters de minimis changes are prohibited under ARM 17.8.745(1)(a)(i) since an applicable rule, specifically ARM 17.8.752 requiring that BACT be utilized, would be violated. Because BACT determinations cannot be changed under the amendment process, DEQ requested that MRC submit an application for a permit modification that would include a revised BACT analysis in order to make the proposed change for the three PMA tank heaters.

In addition, DEQ updated Attachment 1 to reflect the most current permit language and requirements for ambient monitoring. **MAQP #2161-21** replaced MAQP #2161-20.

On December 19, 2008, DEQ received a request from MRC to amend MAQP #2161-21. MRC requested to change the wording for material stored in specified storage tanks to language representative of the requirements of 40 CFR 60, Subpart Kb in order to provide operational flexibility. Instead of referring to specific products (e.g., naphtha, gasoline, diesel, tall oil, etc.), the products would instead be referred to as light oils, medium oils, and heavy oils.

Under MRC's proposed language, light oils would be defined as a volatile organic liquid with a maximum true vapor pressure greater than or equal to 27.6 kilopascal (kPa), but less than 76.6 kPa and would include, but not be limited to, gasoline and naphtha. Medium oils would be defined as volatile organic liquids with a vapor pressure less than 27.6 kPa and greater than or equal to 5.2 kPa and would include, but not be limited to, ethanol. Heavy oils would be defined as volatile organic liquid with a maximum true vapor pressure less than 5.2 kPa and would include, but not be limited to diesel, kerosene, jet fuel, slurry oil, and asphalt.

In addition to making the requested change, DEQ 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. DEQ has also updated Attachment 1, Ambient Monitoring to reflect the most current permit language and requirements for ambient monitoring. **MAQP #2161-22** replaced MAQP #2161-21.

On July 9, 2009, DEQ received a permit application from MRC to modify MAQP #2161-22. The application was deemed complete on July 24, 2009. MRC submitted a permit modification to allow the use of treated refinery fuel gas or natural gas in the tank heaters. Previously, the PMA tanks heaters were permitted to use natural gas only pursuant to a BACT analysis that was completed for MAQP #2161-09. This permit modification applied to three previously permitted asphalt tanks (Tanks #130, 132 and 133) and the associated PMA tank heaters. **MAQP #2161-23** replaced MAQP #2161-22.

On January 15, 2008, DEQ received a request from MRC to install a second hydrogen plant that utilizes a process heater with a heat input of 80 million British thermal units per hour (MMBtu/hr). DEQ approved this de minimis request on February 8, 2008. Pursuant to the Consent Decree (CD) and the approval of the de minimis request, MRC was required to conduct an initial performance test on the process heater with the results reported based upon the average of three, one-hour testing periods. The CD also required MRC to submit an application to DEQ and to propose a NO_x permit limit for the heater. MRC submitted a permit application on December 29, 2009, and DEQ deemed this application incomplete on January 15, 2010. On July 12, 2010, MRC submitted additional information as requested by DEQ. On September 2, 2010, during the comment period, MRC submitted information to support the guaranteed ultra-low NO_x burner emission limit of 0.033 lb/MMBtu based on the Higher Heating Value (HHV) of the fuel. This limit was based on the process heater of the hydrogen plant operating at full capacity (80 MMBtu/hr) with fuel gas consisting of 40.5 % natural gas and 59.4% Pressure Swing Adsorption (PSA) vent gas. This permit modification applied to NO_x limits on the Hydrogen Plant #2 process heater. **MAQP #2161-24** replaced MAQP #2161-23.

On July 6, 2011, MRC submitted a permit application and subsequent modeling demonstration to add a new boiler (Boiler #3) capable of firing refinery fuel gas, SWS overhead gas, or natural gas at the petroleum refinery. The primary purpose of Boiler #3 is to supplement the two existing boilers (#1 and #2) that provide process steam to the refinery. The design burner heat input capacity for Boiler #3 varies, depending upon fuel characteristics, from 59.7 to 60.5 MMBtu/hr. DEQ deemed the application incomplete on August 4, 2011, and MRC provided additional information in response to DEQ's letter on September 26, 2011.

On October 25, 2011, DEQ requested additional information with respect to MRC's plantwide applicability limit (PAL) and the SWS overhead gas combustion properties. This information was received by DEQ on November 15, 2011. Additionally, because MRC experienced significant downtime with the SO_2/O_2 CEMS required on the #1 and #2 Boiler stack, MRC submitted a request to allow the use of the H_2S fuel gas analyzer located near the fuel gas drum as backup to the SO_2/O_2 CEMS. MRC also requested this for Boiler #3.

Therefore, in addition to adding the Boiler #3 to the refinery's operation, the permit action also added compliance, reporting and recordkeeping requirements for allowing the H_2S fuel analyzer to be used as a backup to the SO_2/O_2 CEMS. When the H_2S fuel analyzer is used, MRC would not be allowed to route the SWS overhead gas to the boilers. **MAQP #2161-25** replaced MAQP #2161-24.

On October 24, 2012, DEQ received a request for the transfer of ownership. According to the information submitted, the previous owner, Connacher Oil and Gas, sold its shares of MRC to Calumet Specialty Products Partners. With the transfer of ownership, Calumet Specialty Products Partners also requested a facility name change from MRC to Calumet Montana Refining, LLC. This was an administrative permit action to change the name. **MAQP #2161-26** replaced MAQP #2161-25.

On July 30, 2013, DEQ received an application for modification to MAQP #2161-26. The permit action removed older storage tanks that were located close to the process unit area and in order to accommodate potential future expansion. As such, Calumet requested to remove nine (9) tanks and to add eight (8) new tanks as shown in the table below:

Current Tank ID	Current Service	Current Capacity (in barrels (bbl))	New Tank ID	Service	New Capacity (in bbl)
Tank #122	Unleaded Gasoline	11300	Tank #122	Unleaded Gasoline	20000
Tank #123	Unleaded Gasoline	11300	Tank #123	Unleaded Gasoline	20000
Tank #52	Premium Gasoline	3000	Tank #52	Premium Gasoline	11300
Tank #53	Premium Gasoline	3000	Removed from service		
Tank #46	Kero/Jet A	5140	Tank #49	Kero/Jet A	20000
Tank #47	Kero/Jet A	10500	Tank #47	Kero/Jet A	20000
Tank #48	Kero/Jet A	10500	Tank #48	Kero/Jet A	20000
Tank #50	Asphalt	55700	Tank #50	Asphalt	20000
Tank #102	Asphalt	10300	Tank #102	Asphalt	20000

All kerosene and asphalt tanks were equipped with fixed roofs, and all gasoline storage tanks are equipped with external floating roofs. In addition, tanks 50 and 102 are equipped with two burners (John Zink Burner), each rated at 2.3 MMBtu/hr to keep the asphalt from cooling down and/or hardening. **MAQP #2161-27** replaced MAQP #2161-26.

On October 3, 2013, DEQ received a permit application requesting a major modification under the New Source Review-Prevention of Significant Deterioration (NSR-PSD) program. This permit application was assigned MAQP #2161-28. The project was deemed significant for greenhouses (GHG) and volatile organic compounds (VOCs), and the permit application was deemed complete on February 10, 2014.

With this permit action, Calumet proposed to increase the low sulfur fuels capacity at the refinery from approximately 10,000 bpsd throughput up to 30,000 bpsd while increasing yields of distillates, kerosene, diesel, and asphalt products.

The expansion project included the construction of four new processing units: a new crude unit that will process heavy sour crudes, a MHC for gas-oil conversion to higher value distillates, a new hydrogen plant (#3) to support the MHC, and a fuel gas treatment unit to handle the increased fuel gas production from the MHC.

The main emitting units included with the expansion project are as follows: Hydrogen Plant #3 (equipped with two heaters with a total combined firing rating of up to 134 million British thermal units per hour (MMBtu/hr)); Combined Feed Heater (up to 54 MMBtu/hr); Fractionation Feed Heater (up to 38 MMBtu/hr), Crude Heater (up to 71 MMBtu/hr), Vacuum Heater (up to 27 MMBtu/hr), and a new flare interconnected to the existing flare that will be equipped with a flare gas scrubber. With the expansion, Calumet also proposed to add a new rail car loading (diesel and asphalt) and unloading (crude oil and gas oil) area, and several new storage tanks in addition to re-purposing some existing storage tanks to accommodate the expansion project.

Additionally, the existing HTU that block operated in both diesel and gas-oil service was to become the kerosene HTU, and the existing kerosene HTU was to become a Naphtha HTU. Lastly, Calumet requested a federally enforceable operational limit on Boiler #1 and Boiler #2.

DEQ issued a preliminary determination (PD) as **MAQP #2161-28** on March 18, 2014, final department decision (DD) on April 25, 2014, and final permit on May 13, 2014. However, DEQ did not notify the public by advertisement in a newspaper of general circulation in the Great Falls area in accordance with ARM 17.8.826(2)(c) when it issued the PD for MAQP #2161-28. Therefore, DEQ reissued its PD under **MAQP #2161-29** along with a public notice in the Great Falls Tribune to satisfy the requirements of ARM 17.8.826(2)(c). All project analyses and conclusions from MAQP #2161-28 for this project remained the same. MAQP #2161-29 contained any comments received on the PD for MAQP #2161-28 and corrections made to address them.

On April 4, 2017, DEQ received an application from Calumet to modify the existing MAQP. Incompleteness responses and additional information were received, with final information completing the application on September 26, 2017. Due to various operational and design issues, compliance with certain limits associated with the expansion project permitted in MAQP #2161-29 were determined to be unachievable on a continuous and ongoing basis. These limitations were necessary to avoid the project being determined a major modification of a major stationary source and subject to the permitting requirements of ARM 17.8 Subchapter 8 for NO_X. As such, Calumet proposed an alternative operating scenario and alternative limitations to maintain the project below relevant significant emissions rates.

Calumet proposed to install a new temporary low NO_X boiler (Boiler #4) for additional/supplemental steam production and an ammonia combustor to remove and combust fuel bound nitrogen that otherwise would be present in refinery fuel gas. In addition, Calumet proposed an umbrella limit on emissions of NO_X and CO on a rolling 12-month basis. The umbrella limit would apply to combined emissions from multiple units such that any combination of emissions from these units, provided the overall emissions limitation is adhered to, maintains the project as not a major modification for NO_X or CO. Prior limitations related to PSD avoidance on Boilers #1 and #2 have been removed from the permit.

Calumet has determined a need to reduce fuel-bound nitrogen in fuel gas in order to meet NO_X limitations on various units. Further, Calumet has identified mechanical issues with Boiler #3 which has resulted in the potential for excess NO_X emissions. Bringing a temporary low NO_X boiler on-site will allow Calumet to produce steam for operations while ongoing efforts are undertaken to reduce plant wide NO_X emissions. The low NO_X boiler will provide for reduced emissions of NO_X per pound of steam produced compared to the NO_X performance capabilities of Boilers #1 and #2.

Boiler #3, the new low NO_X boiler, and the ammonia combustor were determined technically and economically related to the expansion project and were included in the expansion project as new units. The purpose of this permitting action is to establish limits which maintain the net emissions increases to less than the significant emissions rates for NO_X and CO, or less than the amount of other emissions previously reviewed for the expansion project. All pollutants were reviewed, and the project was re-permitted as if the project had not been previously permitted. A request in the future to modify or replace associated units would require a reassessment of the project emissions. The allowable operating capacity of the associated refining unit heaters was reduced in the current operational scenario, and future projects to reduce emissions will be necessary to gain full use of the increased refining capacity capable of being accomplished with the associated equipment installed for avoidance of PSD.

During PSD review, Calumet identified that Tank #50 and #102 will not be equipped with tank heaters and the emissions were removed from considerations in contemporaneous emissions increases. **MAQP #2161-30** replaced MAQP #2161-29.

On July 12, 2019, DEQ received from Calumet an application to modify the MAQP. Calumet sought to relax the control requirements on Tanks #125 and #128, due to a finding that the tanks are out-of-round, making seals associated with floating roof design to be infeasible to maintain. These tanks are in heavy liquid service, and as such, DEQ approved request to maintain these tanks as fixed roof tanks with submerged fill. In doing so, the emissions increases associated with the expansion project is updated, and Best Available Control Technology (BACT) review is presented in demonstration that the requirements of BACT are maintained (see the permit analysis). Condition III.B.7.h was established to require the fixed roof tanks be maintained in heavy liquids service with submerged fill practices maintained. Prior requirements that these tanks be maintained with floating roof design was removed. **MAQP #2161-32** replaced MAQP #2161-31.

On December 31, 2019, DEQ received from Calumet a concurrent MAQP and Title V application to revise nitrogen oxides (NO_X) limitations on the #2 Crude Vacuum Heater H-2102 and the Mild Hydrocracker Reactor Fractionation Heater H-4102. These heaters were assigned NO_X limitations as part of Best Available Control Technology (BACT) review associated with the refinery expansion project. The limits were originally set at 0.035 pounds per million British thermal units, on a higher heating value basis, on a 30-day rolling average.

The permit application requested that these limits be revised to 0.040 lb/MMBtu, on a 3-hr basis via an annual source test. The permit action provided for an achievable limitation which is practically enforceable without a requirement for CEMS. The mass-based umbrella limitations for NO_X and CO remained unchanged. **MAQP #2161-33** replaced MAQP #2161-32.

On February 19, 2021, DEQ received from Calumet an application to modify the MAQP for installation of a catalytic thermal oxidizer. Calumet implemented the AOC-16 Remediation Project at the Gasoline and Light Oil Loading Rack area, which included dual-phase extraction in an existing primary recovery trench in the truck rack area, and a passive treatment trench just north of North River Road. The installation of a vapor-liquid separator, with a catalytic thermal oxidizer to destroy VOC vapors, was included as part of this project.

In accord with ARM 17.8.770, a human health risk assessment on the air emissions from the catalytic thermal oxidizer was conducted. Further, a best available control technology review as required by ARM 17.8.752 was conducted. The analyses demonstrated the proposed oxidizer emissions would present a negligible risk to public health, safety, and welfare as defined in ARM 17.8.770, and meet the requirements of BACT as required by ARM 17.8.752. **MAQP #2161-34** replaced MAQP #2161-33.

On July 2, 2021, DEQ received from Calumet an application to modify the MAQP for installation of new equipment and tanks related to the polymer modified asphalt (PMA) production process. This project was titled the Asphalt Upgrades Project. The Asphalt Upgrades Project provided the refinery with improved PMA production capabilities, more advanced asphalt product blending capabilities, and modernized heating systems for PMA process equipment, PMA storage tanks, and asphalt storage tanks. The project also included the shutdown of numerous heaters which were replaced with heaters fired by refinery fuel gas. The project also made changes to the asphalt product blending and storage operations at the refinery. **MAQP #2161-35** replaced MAQP #2161-34.

On August 6, 2021, DEQ received from Calumet an application to modify the MAQP as part of the Refinery Reconfiguration Project which entailed transferring some equipment from Calumet to Montana Renewables, Inc (MRI) for the Great Falls Renewable Diesel Unit (RDU). Additional information was submitted on September 16, 2021, in response to DEQ's incompleteness letter. The application also requested several changes to the existing equipment and to permit some new equipment. It's important to note that equipment scheduled to be transferred to MRI will remain as active equipment under the conditions of MAQP #2161-36 until such time as DEQ issues MRI a final MAQP for the operation of the equipment listed below at RDU <u>and</u> DEQ receives written notification from Calumet identifying the date that service of each piece of equipment listed below was transferred to MRI.

Following is a list of the equipment to be transferred to MRI:

- Mild Hydrocracker (MHC) Combined Feeder Heater (H-4101);
- MHC Fractionator Feed Heater (H-4102) (the emission source will be transferred to MRI, but H-4102 will be out of service because it will not be required to operate in the RDU);
- Hydrogen Plant #3 Reformer Heaters (H-3815A & H-3815B);
- Tanks #29, #50, #102, #112, #116, #125, #128, and #140; and
- MHC Hydrogen Plant #3, and Storage Tank Piping Fugitive Components and Wastewater Components.

The CO and NOx umbrella limits are to be reduced upon Calumet providing written notification that the following emission sources have been transferred to MRI: MHC Combined Feeder Heater (H-4101); MHC Fractionator Feed Heater (H-4102); and Hydrogen Plant #3 Reformer Heaters (H-3815A & H-3815B).

Calumet requested the following changes to existing emission sources that are to remain at the refinery but will be modified to adapt to changing operations as part of the Refinery Reconfiguration Project:

- Crude Unit #2 changes include:
  - changes to piping and valves,
  - modification of fractionator tower components,
  - add a primary off-gas compressor, and
  - add a backup off-gas compressor.
- Hydrotreating Unit (HTU) will be reconfigured to increase its capacity to provide flexibility in the petroleum derived feed streams it is capable of processing including the following changes:
- Purified hydrogen (an unregulated air compound) will be vented by a new stack at the MRI's RDU when there are abrupt process changes at hydrogen consuming process units or Hydrogen Plant #2.
- Allow Flare #1 to receive natural gas purges from MRI's new Hydrogen Plant #4.
- Add Tank #58 (which is reusing a tank designation), a fixed roof atmospheric storage tank that shall store middle distillates that the HTU will be capable of processing; and
- Change locations of some existing loading facilities to accommodate efficient loading and unloading of refinery and MRI's RDU materials separate from one another.

On August 2, 2021, Calumet submitted a *de minimis* change notification for the receipt of a single railcar of canola oil for receipt, unloading and storage. The canola will either be processed in the existing crude unit, transferred, and used by the MRI's RDU, or shipped offsite via railcar. No permit changes were deemed necessary for this *de minimis* change.

A description of the project impacted emitting units is in the table below:

Emissions Unit	Existing/ New Unit	Project Impact
HTU Heater (H-1701) (EPN 26)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. CMR estimated that the project may use all the heater's existing firing rate capacity that is not currently being used. CMR is not proposing to increase the firing rate capacity of the heater.
HTU Fractionation Heater (H-1730)	New	A new fractionation heater will be installed to support the HTU.
Flare #1 (FLR-0701) (EPN 32)	Existing	The flare will receive natural gas purges from the MRI Great Falls Renewable Diesel Plant's new Hydrogen Plant #4. Additionally, CMR anticipates a minor increase in the amount of excess RFG that will be routed to the flare due to a reduction in overall unit operating rates and process heater firing rates at the refinery.
Tank #58	New	A new storage tank will be installed at the refinery to store middle distillates.
Piping Fugitive Components (EPN 33)	Existing/ New	CMR plans to add piping fugitive components (e.g., pumps, compressors, pressure relief devices, open-ended valves or lines, valves, and flanges or other connectors) at the refinery as part of the project.
Wastewater Components	Existing/ New	CMR plans to add drains and sumps at the refinery as part of the project.
Railcar Unloading - Renewable Feed	New	CMR plans to install new railcar racks to unload renewable feed that will be routed to and used by the MRI Great Falls Renewable Diesel Plant.
Loading (EPNs 30 and 39)	Existing/ New	New loading facilities will be installed at the refinery and changes will be made to the location and use of certain existing loading facilities at the refinery to facilitate the efficient loading and unloading of refinery and MRI Great Falls Renewable Diesel Plant materials.
Loading VCU (EPNs 30 and 39)	Existing	In addition to controlling the loading of petroleum derived materials (gasoline and naphtha), the existing railcar VCU will be utilized to control the loading of renewable naphtha.

MAQP #2161-36 replaced MAQP #2161-35.

On December 7, 2021, DEQ received from Calumet a concurrent MAQP and Title V application. The application was considered complete on February 18, 2022. The permit action accomplished several updates, corrections, and changes as presented below:

1. Removal of preconstruction approval for the sour water stripper ammonia combustor. This portion of the permit had expired because it was over 3 years since the unit was permitted and construction had not commenced. Calumet was not seeking to renew approval as originally permitted. Conditions related to the ammonia combustor were removed from the permit.

2. Increase in allowable emissions from the Kerosene Hydrotreater Unit Heater H-1701. Calumet identified that the unit is capable of firing at a higher capacity than previously indicated. The unit was installed in 1992, and was not undergoing physical modification or operational change, however, Calumet requested that the allowable emissions on a pound per hour and ton per year basis be increased to match the realizable maximum capacity of the unit. The permit action defined the maximum allowable emissions (potential to emit) of this unit under the increased maximum firing rates identified. Oxides of Nitrogen limitations on a lb/MMBtu basis remain unchanged. Calumet accepted the responsibility for the guarantee of NO_X emissions when firing above a manufacturer's design firing rate.

3. Correct the listed maximum rated firing rate for the Hydrogen Plant #2 Reformer Heater H-2815. This heater was originally approved through de minimis and was presented as having an 80 MMBtu/hr maximum firing rate capacity. However, as part of the June 29, 2018, Title V permit renewal application, Calumet incorrectly identified the heater as a 65.2 MMBtu/hr heater. The capacity of the heater was listed in the Title V and MAQP as a 65.2 MMBtu/hr heater. The permit action corrected the indicated maximum capacity of the heater to 80 MMBtu/hr, as originally submitted. No change to permit limits or applicable regulatory requirements was necessary.

4. Increase the recognized maximum capacity of the Naphtha HDS Heater H-0402a and Naphtha Splitter Reboiler H-0405 and associated potential to emit. Calumet accepted the responsibility for the guarantee of NO_X emissions when firing above a manufacturer's design firing rate.

5. Conversion of Boiler #3 from the SO_2 emissions limitation and monitoring requirements of NSPS Ja, to the fuel gas H_2S limitations and monitoring requirements of NSPS Ja.

6. Removal of the requirements no longer necessary regarding the old sour water stripper unit that was taken out of service in 2006. The unit was removed from the site.

7. Removal of ambient air quality monitoring requirements. Requiring ambient air quality monitoring for SO_2 concentrations at Calumet is neither necessary nor appropriate because of the following:

   a. The existing air quality is significantly below national ambient air quality standards;
   b. The SO_2 emissions from Calumet are well monitored and limited; and
   c. There are limited sources of SO_2 emissions which may affect ambient SO_2 concentrations in the area.

8. Removal of ability of Boiler #3 to burn Sour Water Stripper Overhead gas. The SWS overhead is burned in Boilers #1 and #2, and Calumet does not intend to burn SWS overhead in Boiler #3.

9. Taking certain reporting frequency obligations from quarterly to semiannual, based on the presence of prompt deviation reporting requirements in the required Title V for this facility and in most cases, an established compliance margin with underlying limits or requirements.

MAQP #2161-37 replaced MAQP #2161-36.

On 8/23/2022, DEQ received from Calumet a concurrent MAQP and Title V application.

Related to the Asphalt Upgrades Project-it requests the following changes:

1. Hot Oil Heater (H-1903) and the Hot Oil Heater (H-1904) while originally planned to operate on either natural gas and refinery fuel gas, will only operate on natural gas. The refinery fuel gas was not connected to these heaters. Modify the permit condition for these heaters to indicate they will only operate on natural gas. H-1904 was never constructed and was removed from the permit in MAQP #2161-40.

2. Revise upward the assumptions for the VOC and H_2S concentrations which were originally used in the previous permit application. Since restarting the PMA Unit, Calumet has learned that the referenced H_2S and VOC concentration estimates for the PMA Unit's storage tanks and process vessels are higher than those assumptions, and the emissions need to be adjusted upward to accommodate the new information.

Related to the Refinery Reconfiguration Project requests the following changes:

3. In the August 4, 2021, Refinery Reconfiguration Project MAQP application that Calumet submitted to DEQ, Calumet indicated that it would install the HTU Fractionation Heater (H-1730) at the refinery as part of the proposed changes to the refinery's Hydrotreating Unit (HTU). However, Calumet has subsequently decided that the HTU Fractionation Heater (H-1730) will not be installed at the refinery. Therefore, the heater should be removed from the refinery's MAQP.

4. In the August 4, 2021, Refinery Reconfiguration Project MAQP application, Calumet indicated that it would transfer Tank #125 to MRL. However, Calumet will not transfer Tank #125 to MRL. Instead, the storage tank will remain in heavy liquids service at the refinery, with the maximum true vapor pressure of the tank's contents not exceeding 0.5 pounds per square inch-absolute (psia), as authorized by the refinery's MAQP. Therefore, the storage tank will not be removed from the refinery's MAQP.

5. In the August 4, 2021, Refinery Reconfiguration Project MAQP application, Calumet indicated that it would transfer the MHC Fractionator Feed Heater (H-4102) to MRL, but MRL would shut down the heater. However, MRL subsequently concluded that the MHC Fractionator Feed Heater (H-4102) would be required to operate in its Renewable Diesel Unit's (RDU's) fractionation process. Therefore, MRL permitted the MHC Fractionator Feed Heater (H-4102) in MAQP No. 5263-01 and changed its description to the "RDU Fractionator Feed Heater (H-4102)." This change impacts the current carbon monoxide (CO) and oxides of nitrogen (NOx) umbrella limits indicated in the refinery's MAQP.

6. In the August 4, 2021, Refinery Reconfiguration Project MAQP application, Calumet indicated the railcar unloading facilities for renewable feeds would be located at the refinery. However, the railcar unloading facilities for renewable feeds are to be located at the MRL Great Falls Renewable Fuels Plant instead. MRL permitted those facilities in MAQP No. 5263-01. Therefore, the renewable feed railcar unloading facilities should be removed from the refinery's MAQP.

7. In the August 4, 2021, Refinery Reconfiguration Project MAQP application, Calumet indicated the railcar loading facilities for renewable diesel would be located at the refinery. However, the railcar loading facilities for renewable diesel are to be located at the MRL Great Falls Renewable Fuels Plant instead. MRL permitted those facilities in MAQP No. 5263-01. Therefore, the renewable diesel railcar loading facilities should be removed from the refinery's MAQP.

8. Calumet will add piping, piping components (valves, flanges, connectors, etc.), and eductors (mixers) at the refinery to reduce the potential for the formation of ammonium carbonate salts in the refinery equipment that will process the RDU sour water stripper overhead stream. Specifically, this new equipment will provide the refinery with the capability to recirculate a liquid stream that will contact the RDU sour water stripper overhead stream, which is expected to minimize the chemical and physical mechanisms that promote the formation of ammonium carbonate salts. The new piping fugitive components will be incorporated into the refinery's leak detection and repair program, as applicable. However, note that most of the new components will contain only a small amount (<2 weight %) of VOC and a negligible amount of hazardous air pollutants. The potential to emit VOC emission rate for these new piping fugitive components is covered by the potential to emit VOC emission rate previously calculated for the additional piping fugitive components estimated to be installed at the refinery as part of the Refinery Reconfiguration Project.

MAQP #2161-38 replaced MAQP #2161-37.

On 02/09/2023, the Department received a request to modify MAQP #2161-38 for conditions which were incorporated from an application received on October 21, 2002. On October 21, 2002, to incorporate required elements from a Consent Decree lodged on December 20, 2001. These elements were incorporated and issued in MAQP #2161-16 on March 19, 2003, and for each requirement were referenced as being required by the Consent Decree. Later permitting actions including MAQP #2161-19 issued on August 15, 2007, and MAQP #2161-24 issued on September 25, 2010, also incorporated additional Consent Decree items. The permitting action requested the removal of the references to the Consent Decree. The requirements of the Consent Decree were replaced with a standard reference for Montana Air Quality Permits using Administrative Rules of Montana (ARM) 17.8.749 - CONDITIONS FOR ISSUANCE OR DENIAL OF PERMIT. For a determination of which permit conditions were impacted by the removal of references to the Consent Decree, review MAQP #2161-38. The application also requested several minor corrections to permit conditions issued in recently permitted actions.

MAQP #2161-39 replaced MAQP #2161-38.

D. Current Permit Action

On June 6, 2025, the DEQ received a request to administratively update MAQP #2161-39 for conditions related to final emissions limits and standards from the 2002 Consent Decree (United States of America, et al., v. Navajo Refining Company, LP, U.S. District Court for the District of New Mexico, Civ. No. 01-1422LH (2002)). Unrelated to the administrative Consent Decree updates, Calumet also requested the removal of Hot Oil Heater 1904 (H-1904), since it was not constructed. Permit conditions for H-1904 were removed. Additionally, equipment which has been transferred to Montana Renewables, LLC, has been removed from the MAQP.

MAQP #2161-40 replaces MAQP #2161-39.

E. Additional Information

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

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available upon request from DEQ. Upon request, DEQ 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 DEQ, 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 DEQ. Calumet shall also comply with the testing and monitoring requirements of this permit.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by DEQ, 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 Clean Air Act of Montana, 75-2-101, *et seq*., MCA.

4. Calumet 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 DEQ upon request.

5. ARM 17.8.110 Malfunctions. (2) DEQ 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.

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

Calumet must maintain compliance with the applicable ambient air quality standards.

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

1. <u>ARM 17.8.304 Visible Air Contaminants</u>. (1) This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes. (2) 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. <u>ARM 17.8.308 Particulate Matter, Airborne</u>. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions are taken to control emissions of airborne particulate matter. (2) Under this rule, Calumet 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. (5) 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. This rule in conjunction with ARM 17.8.302, incorporates by reference 40 CFR Part 60. 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, New Source Performance Standards (NSPS). The applicable NSPS Subparts include, but are not limited to:

    a. Subpart A – General Provisions apply to all equipment or facilities subject to an NSPS Subpart as listed below.

    b. Subpart Dc – Standards of Performance for Small Industrial-Commercial Institutional Steam Generating Units for which construction, modification, or reconstruction is commenced after June 9, 1989. This Subpart applies to Boiler #3, Hot Oil Heater H-1903, and Hot Oil Heater H-1904.

    c. Subpart J – Standards of Performance for Petroleum Refineries. The provisions of this subpart are potentially applicable to the following affected facilities in petroleum refineries: fluid catalytic cracking unit catalyst regenerators, fuel gas combustion devices, and all Claus sulfur recovery plants except Claus plants with a design capacity for sulfur feed of 20 long tons per day (LTD) or less. Regardless of applicability determinations, the following shall be considered affected units, as described per the Consent Decree:

        - FCCU regenerator: for CO and for SO_2, and
        - Heaters, boilers and flare (constructed or modified on or before May 14/2007).

    The following are noted as included as Subpart J applicable units:

- Crude Unit #1 Atmospheric Tower Heater H-0101
- Crude Unit #1 Vacuum Tower Heater H-0102
- FCCU Catalyst Regenerator
- FCCU Preheater H-0302
- Reformer Heater H-0403
- Alkylation Unit Deisobutanizer Reboiler Heater
- Hydrogen Plant #1 Furnace H-1801
- Tank #55, 110, 112, 130, 132, 133, 135, 137, 139, 140 Heaters
- Hydrotreater Unit Kerosene Heater
- HTU Heater H-1701
- Boiler #1
- Boiler #2

d. Subpart Ja – Standards of Performance for Petroleum Refineries for which Construction, Reconstruction or Modification Commenced After May 14, 2007. The provisions of this subpart potentially apply to the following affected facilities in petroleum refineries: fluid catalytic cracking units (FCCU), fluid coking units (FCU), delayed coking units, fuel gas combustion devices (including process heaters), flares and sulfur recovery plants.

e. The following are noted as included as Subpart Ja applicable units:

- Crude Unit #2 Atmospheric Tower Heater H-2101
- Crude Unit #2 Vacuum Tower Heater H-2102
- Naphtha HDS Heater H-0402a
- Naphtha Slitter Reboiler H-0405
- Hydrogen Plant #2 Furnace H-2815
- Tank #138 Heater
- Boiler #3
- Flare #1
- Flare #2
- Hot Oil Heater H-1903

f. Subpart Kb – Volatile Organic Liquid Storage Vessels (including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction or Modification Commenced After July 23, 1984.

g. Subpart UU – Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture – shall apply to all asphalt storage tanks that process and store only non-roofing asphalts, and was constructed or modified since May 26, 1981.

The following are noted as included as Subpart UU affected units:

- Tanks #107, #139, #55

h. Subpart VV – Standards of Performance for Equipment Leaks of Volatile Organic Compounds (VOC) in the Synthetic Organic Chemicals Manufacturing Industry, shall apply to this refinery as required by 40 CFR 60 Subpart GGG and 40 CFR 63 Subpart CC.

i. Subpart VVa - Standards of Performance for Equipment Leaks of VOC shall apply to this refinery as required by 40 CFR 60 Subpart GGGa.

j. Subpart GGG – Equipment Leaks of VOC in Petroleum Refineries. Affected units include the equipment components in the following process units:

- Crude Unit #1
- Fluid Catalytic Cracking Unit
- Hydrogen Plant #1
- HTU (Once DEQ receives written notification that the emission source has been reconfigured to increase capacity for the Refinery Reconfiguration Project, the emission source will no longer be regulated by this condition.)
- Polymer Modified Asphalt Unit

k. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006. Unless exempt, this standard applies to compressors, valves, pumps, pressure relief devices, sampling connection system, open-ended valves and lines, flanges, and connectors in the following units:

- Crude Unit #2
- Catalytic Reformer and Naphtha Units
- Hydrogen Plant #2
- HTU
- NaHS Equipment Components
- Flare Gas Scrubber Components
- PMA Unit Piping Components

l. Subpart QQQ – VOC Emissions from Petroleum Refinery Wastewater Systems. Affected units subject to this subpart includes the individual drain systems associated with the process units throughout the refinery.

8. ARM 17.8.341 Emissions Standards for Hazardous Air Pollutants, in conjunction with ARM 17.8.302, incorporates by reference 40 CFR Part 61.

a. Subpart FF – National Emissions Standard for Benzene Waste Operations is applicable to the individual drain systems throughout the refinery as well as the wastewater treatment system.

9. ARM 17.8.342 Emissions Standards for Hazardous Air Pollutants for Source Categories, in conjunction with ARM 17.8.302, incorporates by reference 40 CFR Part 63 - National Emissions Standards for Hazardous Air Pollutants. Calumet shall comply with all applicable requirements of 40 CFR Part 63, maximum achievable control technology (MACT).

   a. Subpart A – General Provisions applies to all National Emission Standards for Hazardous Air Pollutants (NESHAP) source categories subject to a Subpart as listed below.

   b. Subpart Q - Calumet shall comply with 40 CFR 63 Subpart Q – NESHAP for Industrial Process Cooling Towers, during any timeframe in which 40 CFR 63 Subpart Q is applicable. This MACT is only applicable to industrial process cooling towers that are operated with chromium-based water treatment chemicals.

   c. Subpart R - NESHAP for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations) applies as specified under Subpart CC, to the loading of gasoline at the gasoline truck loading rack and the gasoline railcar loading rack.

   d. Subpart CC - NESHAP Pollutants from Petroleum Refineries is potentially applicable to miscellaneous process vents, storage vessels, wastewater streams and treatment operations, equipment leaks from refining process units, gasoline loading racks, heat exchange systems, delayed coking units, pumps, compressors, pressure relief devices, sampling connection systems, valves and open-ended valve or lines, catalytic cracking unit and catalytic reformer unit catalyst regeneration vents, sulfur plant vents, emission points routed to a fuel gas system, and any flares receiving gas from that fuel gas system. Fence line monitoring is also required.

   e. Subpart UUU – NESHAP for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units, shall apply to, but not be limited to, the FCCU and the Catalytic Reformer Unit.

   f. Subpart EEEE – NESHAP for Organic Liquids Distribution (non-gasoline) shall apply to, but not be limited to, Tank #1 (DEGME) and the naphtha loading racks.

   g. Subpart FFFF – NESHAP for Miscellaneous Organic Chemical Manufacturing shall apply to, but not be limited to piping fugitive components, wastewater components, and transfer racks at the refinery that are used to load renewable products produced by the MRI-RDU.

   h. Subpart DDDDD – NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, applies to all boilers and process heaters as specified in Subpart DDDDD.

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

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

b. ARM 17.8.402 Requirements. Calumet must demonstrate compliance with the ambient air quality standards based on the use of Good Engineering Practices (GEP) stack height.

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

a. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to DEQ. Calumet submitted the required application fee for this permit action.

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

c. 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. DEQ 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:

a. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

b. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. Calumet has a PTE greater than 25 tons per year of

PM, NO_x, CO, VOC, and SO_2; therefore, an air quality permit is required.

c. <u>ARM 17.8.744 Montana Air Quality Permits--General Exclusions</u>. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

d. <u>ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes</u>. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

e. <u>ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements</u>. (1) This rule requires that a permit application be submitted prior to installation, modification or use of a source. A permit application was not required for the current permit action because the permit change is considered an administrative permit change. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. An affidavit of publication of public notice was not required for the current permit action because the permit change is considered an administrative permit change

f. <u>ARM 17.8.749 Conditions for Issuance or Denial of Permit</u>. This rule requires that the permits issued by DEQ 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.

g. <u>ARM 17.8.752 Emission Control Requirements</u>. 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.

h. <u>ARM 17.8.755 Inspection of Permit</u>. This rule requires that air quality permits shall be made available for inspection by DEQ at the location of the source.

i. <u>ARM 17.8.756 Compliance with Other Requirements</u>. This rule states that nothing in the permit shall be construed as relieving Calumet 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.

j. <u>ARM 17.8.759 Review of Permit Applications</u>. This rule describes DEQ'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.

k. 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.

l. 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).

m. 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.

n. 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 DEQ.

o. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to DEQ 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:

a. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

b. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemption. 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 chapter would otherwise allow.

Calumet's existing petroleum refinery in Great Falls is defined as a "major stationary source" because it is a listed source with the PTE more than 100 tons of several pollutants (PM, SO_2, NO_X, CO, and VOC).

The action reviewed for MAQP #2161-37 does not trigger PSD review because the project emission increases (based on the potential to emit of each new or physically modified source and increases from existing non-modified, project impacted sources) are below the PSD major modification thresholds.

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

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

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

a. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any stationary source having:

PTE > 100 TPY of any pollutant;

PTE > 10 TPY of any one HAP, PTE > 25 TPY of a combination of all HAPs, or a lesser quantity as DEQ may establish by rule; or

PTE > 70 TPY of particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}) in a serious PM_{10} nonattainment area.

b. ARM 17.8.1204 Air Quality Operating Permit Program. (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 #2161-40 for Calumet, the following conclusions were made:

i. The facility's PTE is greater than 100 TPY for several pollutants.

ii. The facility's PTE is greater than 10 TPY for a single HAP and greater than 25 TPY of combined HAPs.

iii. This source is not located in a serious PM_{10} nonattainment area.

iv. This facility is subject to NSPS requirements (including 40 CFR 60, Subparts A, J, Ja, Dc, Kb, UU, VV, VVa, GGG, GGGa, and QQQ).

v. This facility is subject to current NESHAP standards (including 40 CFR 61, Subparts, FF)

vi. This facility is subject to current NESHAP standards (including 40 CFR 63, Subparts A, R, CC, UUU, EEEE, FFFF, ZZZZ and DDDDD).

vi. This source is not a Title IV affected source.

vii. This facility is not a solid waste combustion unit.

viii. This source is not an EPA designated Title V source.

Based on these facts, DEQ determined that Calumet is a major source of emissions as defined under Title V.

III. BACT Analysis

A BACT determination is required for each new or modified source. Calumet shall install BACT on the new or modified sources that is technically practicable and economically feasible. The current permitting action is an administrative amendment and therefore a BACT analysis was not required.

IV. Emission Inventory

The changes to the emission inventory recent PSD analyses are shown from the original Asphalt Upgrades project application to the revised application are summarized below. The Asphalt Upgrades Project remains below PSD significance levels.

Asphalt Upgrade PSD Review				
Pollutant	**New Project-Only Emissions Increase[3] (TPY)**	**Original Project-Only Emissions Increase[3] (TPY)**	**PSD Significant Threshold (TPY)**	**Subject to PSD Review? (Yes/No)**
CO	5.26	5.26	100	No
NO_X	5.26	5.26	40	No
PM (filterable only)	0.26	0.26	25	No
PM_{10}	0.99	0.99	15	No

$PM_{2.5}$	0.98	0.98	10	No
SO_2	0.08	1.07	40	No
VOC	26.23	5.26	40	No
H_2S	7.77	0.28	10	No

Similarly, for the Refinery Reconfiguration Project the original emissions increases are shown versus the revised emissions increases versus the PSD thresholds. The primary change is the revised plan to no longer construct H-1701. The Refinery Reconfiguration Project remains below PSD significance levels.

Refinery Reconfiguration PSD Review				
Pollutant	**New Project-Only Emissions Increase[6] (TPY)**	**Original Project Only Emissions Increase[7] (TPY)**	**PSD Significant Threshold (TPY)**	**Subject to PSD Review (Yes/No)**
CO	6.37	11.05	100	No
NO_X	4.33	6.87	40	No
PM (filterable only)	0.08	0.23	25	No
PM10	0.31	0.93	15	No
PM2.5	0.31	0.93	10	No
SO2	0.85	1.53	40	No
VOC	18.27	23.38	40	No

Emission Unit: HTU Heater (H-1701)

Emission Unit Parameters	
Hourly Avg. Firing Rate	22.5 MMBtu/hr, HHV
Hourly Max. Firing Rate	22.5 MMBtu/hr, HHV
Fuel Type	Refinery Fuel Gas
Avg. Fuel Heating Value [1]	1,220 Btu/scf, HHV
Min. Fuel Heating Value [1]	907 Btu/scf, HHV
Avg. H_2S Concentration [2]	60 ppmv
Max. H_2S Concentration [2]	162 ppmv
Hours of Operation	8,760 hr/yr
Global Warming Potentials (GWP) [3]	
CO_2	1
CH_4	25
N_2O	298

Pollutants	Emission Factor	Hourly Avg. (lb/hr)	Hourly Max. (lb/hr)	Annual (tpy)
Criteria Pollutants [4]				
PM (filterable)	0.0019 lb/MMBtu	0.04	0.04	0.18
PM_{10} (filterable + condensable)	0.0075 lb/MMBtu	0.17	0.17	0.73
$PM_{2.5}$ (filterable + condensable)	0.0075 lb/MMBtu	0.17	0.17	0.73
NOx	0.07 lb/MMBtu	1.58	1.58	6.90
VOC	0.0054 lb/MMBtu	0.12	0.12	0.53
CO	0.039 lb/MMBtu	0.88	0.88	3.84
SO_2	- -	0.18	0.67	0.81
Greenhouse Gases [5]				
CO_2	130.07 lb/MMBtu	-	-	12,819
CH_4	0.0066 lb/MMBtu	-	-	0.65
N_2O	0.0013 lb/MMBtu	-	-	0.13
CO_2e	- -	-	-	12,874

Notes:

[1] Fuel heating value based on actual refinery fuel gas data (2015 calendar year data) determined to be a conservative representation of refinery fuel gas heating value for SO_2 emission calculations.

[2] NSPS Subpart Ja fuel gas H_2S limitations (162 ppmv on a 3-hour rolling average basis and 60 ppmv on a 365 successive calendar day rolling average basis).

[3] Values are EPA-designated global warming potential for specific greenhouse gases (40 CFR Part 98 Subpart A).

[4] PM (filterable), PM_{10}, $PM_{2.5}$, and VOC emission factors obtained from AP-42, Section 1.4, Table 1.4-2. Emission factors were corrected using typical natural gas heating value of 1,020 Btu/scf, as directed by footnote "a" of that table.
NOx emission factor is the unit's NOx emission limitation.
CO emission factor was derived based on the unit's hourly and annual CO emission rate limitations.
SO_2 emissions based on H_2S concentration of refinery fuel gas and 100% conversion of H_2S to SO_2.

[5] Emission factors obtained from 40 CFR Part 98 Subpart C, Tables C-1 and C-2 for fuel gas.

The Naphtha HDS Heater (H-0402a):

Emission Unit: Naphtha HDS Heater (H-0402a)

Emission Unit Parameters	
Hourly Avg. Firing Rate	13.6 MMBtu/hr, HHV
Hourly Max. Firing Rate	13.6 MMBtu/hr, HHV
Fuel Type	Refinery Fuel Gas
Avg. Fuel Heating Value [1]	1,220 Btu/scf, HHV
Min. Fuel Heating Value [1]	907 Btu/scf, HHV
Avg. H_2S Concentration [2]	60 ppmv
Max. H_2S Concentration [2]	162 ppmv
Hours of Operation	8,760 hr/yr
Global Warming Potentials (GWP) [3]	
CO_2	1
CH_4	25
N_2O	298

Pollutants	**Emission Factor**	**Hourly Avg. (lb/hr)**	**Hourly Max. (lb/hr)**	**Annual (tpy)**
Criteria Pollutants [4]				
PM (filterable)	0.0019 lb/MMBtu	0.03	0.03	0.11
PM_{10} (filterable + condensable)	0.0075 lb/MMBtu	0.10	0.10	0.44
$PM_{2.5}$ (filterable + condensable)	0.0075 lb/MMBtu	0.10	0.10	0.44
NOx	0.03 lb/MMBtu	0.41	0.41	1.79
VOC	0.0054 lb/MMBtu	0.07	0.07	0.32
CO	0.04 lb/MMBtu	0.54	0.54	2.38
SO_2	- -	0.11	0.40	0.49
Greenhouse Gases [5]				
CO_2	130.07 lb/MMBtu	-	-	7,748
CH_4	0.0066 lb/MMBtu	-	-	0.39
N_2O	0.0013 lb/MMBtu	-	-	0.08
CO_2e	- -	-	-	7,781

Notes:

[1] Fuel heating value based on actual refinery fuel gas data (2015 calendar year data) determined to be a conservative representation of refinery fuel gas heating value for SO_2 emission calculations.

[2] NSPS Subpart Ja fuel gas H_2S limitations (162 ppmv on a 3-hour rolling average basis and 60 ppmv on a 365 successive calendar day rolling average basis).

[3] Values are EPA-designated global warming potential for specific greenhouse gases (40 CFR Part 98 Subpart A).

[4] PM (filterable), PM_{10}, $PM_{2.5}$, and VOC emission factors obtained from AP-42, Section 1.4, Table 1.4-2. Emission factors were corrected using typical natural gas heating value of 1,020 Btu/scf, as directed by footnote "a" of that table.

NOx and CO emission factors based on burner vendor specifications.

SO_2 emissions based on H_2S concentration of refinery fuel gas and 100% conversion of H_2S to SO_2.

[5] Emission factors obtained from 40 CFR Part 98 Subpart C, Tables C-1 and C-2 for fuel gas.

Naphtha Splitter Reboiler H-0405:

Emission Unit: Naphtha Splitter Reboiler (H-0405)

Emission Unit Parameters	
Hourly Avg. Firing Rate	9.9 MMBtu/hr, HHV
Hourly Max. Firing Rate	9.9 MMBtu/hr, HHV
Fuel Type	Refinery Fuel Gas
Avg. Fuel Heating Value [1]	1,220 Btu/scf, HHV
Min. Fuel Heating Value [1]	907 Btu/scf, HHV
Avg. H_2S Concentration [2]	60 ppmv
Max. H_2S Concentration [2]	162 ppmv
Hours of Operation	8,760 hr/yr
Global Warming Potentials (GWP) [3]	
CO_2	1
CH_4	25
N_2O	298

Pollutants	Emission Factor	Hourly Avg. (lb/hr)	Hourly Max. (lb/hr)	Annual (tpy)
Criteria Pollutants [4]				
PM (filterable)	0.0019 lb/MMBtu	0.02	0.02	0.08
PM_{10} (filterable + condensable)	0.0075 lb/MMBtu	0.07	0.07	0.32
$PM_{2.5}$ (filterable + condensable)	0.0075 lb/MMBtu	0.07	0.07	0.32
NOx	0.03 lb/MMBtu	0.30	0.30	1.30
VOC	0.0054 lb/MMBtu	0.05	0.05	0.23
CO	0.04 lb/MMBtu	0.40	0.40	1.73
SO_2	- -	0.08	0.29	0.35
Greenhouse Gases [5]				
CO_2	130.07 lb/MMBtu	-	-	5,640
CH_4	0.0066 lb/MMBtu	-	-	0.29
N_2O	0.0013 lb/MMBtu	-	-	0.06
CO_2e	- -	-	-	5,664

Notes:

[1] Fuel heating value based on actual refinery fuel gas data (2015 calendar year data) determined to be a conservative representation of refinery fuel gas heating value for SO_2 emission calculations.

[2] NSPS Subpart Ja fuel gas H_2S limitations (162 ppmv on a 3-hour rolling average basis and 60 ppmv on a 365 successive calendar day rolling average basis).

[3] Values are EPA-designated global warming potential for specific greenhouse gases (40 CFR Part 98 Subpart A).

[4] PM (filterable), PM_{10}, $PM_{2.5}$, and VOC emission factors obtained from AP-42, Section 1.4, Table 1.4-2. Emission factors were corrected using typical natural gas heating value of 1,020 Btu/scf, as directed by footnote "a" of that table.

NOx and CO emission factors based on burner vendor specifications.

SO_2 emissions based on H_2S concentration of refinery fuel gas and 100% conversion of H_2S to SO_2.

[5] Emission factors obtained from 40 CFR Part 98 Subpart C, Tables C-1 and C-2 for fuel gas.

Reformer Heater H-0403:

Emission Unit: Reformer Heater (H-0403)

Emission Unit Parameters	
Hourly Avg. Firing Rate	24.2 MMBtu/hr, HHV
Hourly Max. Firing Rate	24.2 MMBtu/hr, HHV
Fuel Type	Refinery Fuel Gas
Avg. Fuel Heating Value [1]	1,220 Btu/scf, HHV
Min. Fuel Heating Value [1]	907 Btu/scf, HHV
Avg. H_2S Concentration [2]	60 ppmv
Max. H_2S Concentration [2]	162 ppmv
Hours of Operation	8,760 hr/yr
Global Warming Potentials (GWP) [3]	
CO_2	1
CH_4	25
N_2O	298

Pollutants	**Emission Factor**	**Hourly Avg. (lb/hr)**	**Hourly Max. (lb/hr)**	**Annual (tpy)**
Criteria Pollutants [4]				
PM (filterable)	0.0019 lb/MMBtu	0.05	0.05	0.20
PM_{10} (filterable + condensable)	0.0075 lb/MMBtu	0.18	0.18	0.79
$PM_{2.5}$ (filterable + condensable)	0.0075 lb/MMBtu	0.18	0.18	0.79
NOx	0.098 lb/MMBtu	2.37	2.37	10.40
VOC	0.0054 lb/MMBtu	0.13	0.13	0.57
CO	0.0824 lb/MMBtu	1.99	1.99	8.74
SO_2	- -	0.20	0.72	0.87
Greenhouse Gases [5]				
CO_2	130.07 lb/MMBtu	-	-	13,800
CH_4	0.0066 lb/MMBtu	-	-	0.70
N_2O	0.0013 lb/MMBtu	-	-	0.14
CO_2e	- -	-	-	13,860

Notes:

[1] Fuel heating value based on actual refinery fuel gas data (2015 calendar year data) determined to be a conservative representation of refinery fuel gas heating value for SO_2 emission calculations.

[2] NSPS Subpart Ja fuel gas H_2S limitations (162 ppmv on a 3-hour rolling average basis and 60 ppmv on a 365 successive calendar day rolling average basis).

[3] Values are EPA-designated global warming potential for specific greenhouse gases (40 CFR Part 98 Subpart A).

[4] PM (filterable), PM_{10}, $PM_{2.5}$, and VOC emission factors obtained from AP-42, Section 1.4, Table 1.4-2. Emission factors were corrected using typical natural gas heating value of 1,020 Btu/scf, as directed by footnote "a" of that table.

NOx and CO emission factors obtained from AP-42, Section 1.4, Table 1.4-1 (Small Boilers <100 MMBtu/hr, Uncontrolled). Emission factors were corrected using typical natural gas heating value of 1,020 Btu/scf, as directed by footnote "a" of that table.

SO_2 emissions based on H_2S concentration of refinery fuel gas and 100% conversion of H_2S to SO_2.

[5] Emission factors obtained from 40 CFR Part 98 Subpart C, Tables C-1 and C-2 for fuel gas.

V. Existing Air Quality

As of July 8, 2002, Cascade County is designated as an Unclassifiable/Attainment area for all criteria pollutants.

VI. Ambient Air Impact Analysis

The current ambient air quality status in the area is unclassifiable/attainment for all criteria pollutants. The current permitting action is administrative and would not cause or contribute to an ambient air quality or increment exceedance.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, DEQ conducted the following private property taking and damaging assessment.

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	X	4. Does the action deprive the owner of all economically viable uses of the property?
	X	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	X	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	X	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	X	7a. Is the impact of government action direct, peculiar, and significant?
	X	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
	X	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

Based on this analysis, DEQ determined there are no taking or damaging implications associated with this permit action.

VIII. Environmental Assessment

An environmental assessment was not required as this action is an administrative amendment.