Montana Department of
ENVIRONMENTAL QUALITY

Steve Bullock, Governor
Tracy Stone-Manning, Director

P. O. Box 200901 Helena, MT 59620-0901 (406) 444-2544 Website: www.deq.mt.gov

April 25, 2014

Dana Leach
Calumet Montana Refining Company, LLC
1900 10th Street North East
Great Falls, MT 59404

Dear Mr. Leach:

The Department of Environmental Quality (Department) has made its decision on the Montana Air Quality Permit application for the Low Sulfur Fuels Expansion Project at Calumet Montana Refining, LLC. The application was given permit number 2161-28. The Department's decision may be appealed to the Board of Environmental Review (Board). A request for hearing must be filed by May 27, 2014. This permit shall become final on May 13, 2014, unless the Board orders a stay on the permit.

Procedures for Appeal: Any person jointly or severally adversely affected by the final action may request a hearing before the Board. Any appeal must be filed before the final date stated above. The request for a hearing shall contain an affidavit setting forth the grounds for the request. Any hearing will be held under the provisions of the Montana Administrative Procedures Act. Submit requests for a hearing in triplicate to: Chairman, Board of Environmental Review, P.O. Box 200901, Helena, Montana 59620.

Conditions: See attached.

For the Department,

Julie A Merkel

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

Ed Warner

Ed Warner
Lead Engineer - Air Permitting Section
Air Resources Management Bureau
(406) 444-2467

JM:EW
Enclosure

MONTANA AIR QUALITY PERMIT

Issued to:	Calumet Montana Refining, LLC 1900 10th Street North East Great Falls, MT 59404	MAQP: #2161-28 Application Received: 10/03/2013 Application Deemed Complete: 2/10/2014 Preliminary Determination Issued: 03/18/2014 Department Decision Issued: 04/25/2014 Permit Final: AFS#: 013-0004

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

Plant Location

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.

Permitted Facility

The major permitted equipment at Calumet includes:

- #1 Crude Unit (up to 10,000 barrels per stream day (bpsd));
- #2 Crude Unit (up to 20,000 bpsd));
- Fluid Catalytic Cracking Unit (FCCU);
- Mild Hydrocracker Unit (MHC);
- Hydrogen Plant #1, #2, and #3;
- 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);
- Process Heaters for #2 Crude Unit (Crude Heater, Vacuum Heater, Combined Feed Heater, Fractionation Feed Heater);
- Polymer-Modified Asphalt (PMA) Unit;
- Storage Tanks (heated asphalt, crude oil, 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; and
- Utilities (Boilers (#1, #2 and #3), cooling towers, wastewater treatment).

A complete list of permitted equipment for Calumet is contained in Section I.A. of the permit analysis.

Current Permit Action

On October 3, 2013, the Montana Department of Environmental Quality – Air Resources Management Bureau (Department) received a permit application requesting a major modification under the New Source Review-Prevention of Significant Deterioration (NSR-PSD) program. 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 plans 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 includes 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 proposes 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 currently block operates in both diesel and gas-oil service will become the kerosene HTU, and the existing kerosene HTU will become a Naptha HTU. Lastly, Calumet requested a federally enforceable operational limit on Boiler #1 and Boiler #2.

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 the #3 Boiler.

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:

   i. FCCU regenerator: for carbon monoxide (CO) and sulfur dioxide (SO_2) (pursuant to Calumet's Consent Decree (Consent Decree)).

   ii. Heaters and boilers (Consent Decree).

   iii. Primary Flare (Flare #1) is subject to Subpart J until startup of the modified flare system (Flare #1 and Flare #2). At such time, the entire modified flare system would be subject to 40 CFR 60, Subpart Ja (Consent Decree, 40 CFR 60, Subpart J and 40 CFR 60, Subpart Ja).

d. Subpart Ja – Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction or Modification commenced after May 14, 2007 (#2 Crude Unit's fuel combustion devices (H-2101, H-2102, H-4101, H-4102, H-31A, H-31B , Boiler #3, flare system, fuel gas treatment unit (FGT), and sour water stripper (SWS)).

   i. By November 11, 2015, or upon startup of the modified flare system, whichever is later, Calumet shall comply with the requirements of 40 CFR 60, Subpart Ja).

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.

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, Diesel/Gas Oil HDS Unit, Hydrogen Plant, and any other equipment as appropriate. A monitoring and maintenance program as described under 40 CFR 60, Subpart VV shall be instituted.

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.

k. Subpart QQQ – Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to the wastewater treatment system, individual drains, oil-water separators, HTU, Hydrogen Unit, and any other applicable equipment constructed, modified or reconstructed after May 4, 1987.

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

   c. 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.

   d. 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.

   e. 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.

B. 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. These periods of startup, shutdown, and malfunction shall not exceed 9 hours per year based on a 12-month rolling average (40 CFR 60, Subpart Ja and 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 diesel/gas oil HDS heater 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. Hydrogen Plant #2 must be equipped with a next-generation ultra-low NO_x burner (ULNB) on the heater (Consent Decree and ARM 17.8.749).

5. Hydrogen Plant #3 must be equipped with ULNB and the total combined capacity of the two heaters (H-31A and H-31B) shall not exceed 134 MMBtu/hr (ARM 17.8.752).

6. All process heaters in the # 2 Crude Unit (H-2101, H-2102, H-4101, H-4102) shall be equipped with ULNB (ARM 17.8.749 and ARM 17.8.752).

7. Storage Tanks

   a. Storage tanks #47, #48, #49, #54, and #58 shall be used to store kerosene/Jet A and shall be equipped with fixed roof tanks (ARM 17.8.749 and ARM 17.8.752).

   b. Storage tanks #50 and #102 shall be equipped with a fixed roof (ARM 17.8.752).

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

   d. Storage tank #52 shall be used to store premium gasoline and shall be equipped with external floating roofs and a mechanical shoe seal (ultracheck safe sleeve or equivalent) (ARM 17.8.752).

   e. 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).

   f. Storage tanks #57 and #124 shall be used to store Naptha, and Tank #57 shall be equipped with a double seal internal floating roof (ARM 17.8.752).

   g. Storage tanks #122, #124, #125, #126, #145B, #201, #202, and #203 shall be equipped with dual-seal external floating roofs with guide pole sleeves (ARM 17.8.752).

   h. Storage tank #128 shall be equipped with dual-seal external floating roofs. The primary seals shall be visually inspected for holes every 5 years and the secondary seals shall be visually inspected for holes annually (ARM 17.8.752).

   i. Storage tanks #50, #55, #56, #69 #102, #110, #112, #130, #132, #133, #135, #137, #139, #140, #201, #202, and #203 shall be used for heavy oil (ARM 17.8.749).

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

k. Asphalt tank heaters #135, #137, #139 and #140 shall burn only natural gas or refinery fuel gas in compliance with 40 CFR 60, Subpart J (ARM 17.8.749, Consent Decree, and 40 CFR 60, Subpart J).

l. Asphalt tank heaters #50, #102 and #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. The three 0.75 MMBtu/hr PMA tank heaters (tanks #130, #132, and #133), shall burn natural gas or refinery fuel gas in compliance with 40 CFR 60, Subpart J (ARM 17.8.752, Consent Decree, and 40 CFR 60, Subpart J).

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).

8. 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).

9. 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, Consent Decree, and 40 CFR 60, Subpart J).

10. 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. All pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors shall meet the standards described in 40 CFR 60.482-8. Repairs shall be made promptly as described in 40 CFR 60.482-7(e) (ARM 17.8.752).

11. Calumet shall ensure that the NaHS Unit, Diesel/Gas Oil HDS Unit, Hydrogen Plants, and any other equipment as appropriate, comply with the applicable requirements in 40 CFR 63, Subpart GGG, including (ARM 17.8.342 and 40 CFR 63, Subpart GGG):

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.

12. 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).

13. Cooling Towers – Cooling water shall be monitored twice per shift for changes, specifically pH and hydrocarbon content. The appearance of the towers and related equipment shall be inspected at least once per shift (ARM 17.8.749 and ARM 17.8.752).

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

15. The #3 Boiler shall only combust pipeline quality natural gas, refinery fuel gas or SWSOH (ARM 17.8.752).

16. When the SO_2/O_2 Continuous Emissions Monitoring System (CEMS) is operational on the boiler stacks, Calumet may incinerate the HTU SWSOH in the #1, #2 and #3 boilers. Incineration of the SWSOH and combustion of any refinery fuel gas shall meet the applicable limitations in 40 CFR 60, Subpart J (Boiler #1 and Boiler #2) or Subpart Ja (Boiler #3), as applicable (Consent Decree, ARM 17.8.340, ARM17.8.749, and 40 CFR 60, Subpart J and 40 CFR 60, Subpart Ja).

17. Calumet shall not re-activate the old SWS unit that was taken out of stripping service in 2006, without conducting a permitting analysis in conformance with ARM 17.8 Subchapter 7, and obtaining Department approval, in writing (ARM 17.8.749).

18. 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 the Department 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:

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

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

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

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

19. The gasoline railcar loading rack and VCU shall be operated and maintained as follows:

a. Gasoline and naphtha will be the only products loaded from the gasoline railcar loading rack (ARM 17.8.749).

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

c. 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).

d. 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).

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

f. Calumet shall ensure that loading of 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).

g. 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:

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

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

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

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

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

i. 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).

j. 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).

k. 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).

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

20. 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 (Consent Decree, ARM 17.8.340 and 40 CFR 60, Subpart J).

21. 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 (ppm_{vd}) determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppm_{vd} determined daily on a 365-successive calendar day rolling average basis (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Ja).

22. Calumet shall not combust fuel oil in any combustion unit, except torch oil may be used in the FCCU Regenerator during FCCU startups (Consent Decree).

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

C. Emission Limitations:

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

a. SO_2:

- Annual 1515 tons per year (TPY)
- Daily 4.15 tons/rolling 24-hours

b. CO:

- Annual 4700 TPY
- Daily 12.9 tons/rolling 24-hours

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

   a. SO_2 (ARM 17.8.749):

      - Annual 648 TPY averaged over a 1-year period
      - Hourly 148 pounds per hour (lb/hr) averaged over 1 year
      - 174 lb/hr averaged over a 24-hour period
      - 355 lb/hr averaged over a 3-hour period

   b. Oxides of Nitrogen (NO_x) (ARM 17.8.752):

      - Annual 335 TPY
      - Hourly 76.50 lb/hr

   c. CO (ARM 17.8.752):

      - Annual 4.4 TPY
      - Hourly 1.00 lb/hr

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

   e. Once construction of the #2 Crude Unit is complete, the #1 Boiler and #2 Boiler will no longer be subject to II.C.2.b, but shall be subject to the following:

      - The combined fuel usage for #1 Boiler and the #2 Boiler shall not exceed 106.5 million standard cubic feet per year (MMscf/yr) based on a 12-month total (or a demonstrated equivalent NO_x reduction of 34.12 TPY) (ARM 17.8.749).

      - Prior to startup of the #2 Crude Unit, Calumet shall test the #1 Boiler and the #2 Boiler in accordance with Section II.E. Within 60 days of the completed test, Calumet shall propose to the Department an operational fuel usage limit (at least equivalent to a NO_x reduction of 34.12 TPY) (ARM 17.8.749).

3. #3 Boiler emissions:

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

   b. NO_x emission limit shall be based on the actual performance as demonstrated by the required initial performance test, but shall not exceed 0.019 pounds per million British thermal units (lb/MMBtu) (1.15 lb/hr) on a 3-hour average basis (Consent Decree and ARM 17.8.752).

   c. SO_2 emissions shall not exceed 20 parts per million volume, dry (ppm_{vd}) at 0% oxygen (ARM 17.8.752).

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

4. HDS Furnace Stack

   a. NO_x emissions shall not exceed the limit of 0.07 lb/MMBtu, 1.42 lb/hr, or 6.2 TPY (ARM 17.8.752).

   b. CO emissions shall not exceed the limit of 0.79 lb/hr or 3.5 TPY (ARM 17.8.752).

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

5. Hydrogen Plant Reformer Furnace Stack

   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).

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

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

6. Hydrogen Plant #2

   a. NO_x emissions from the process heater shall be controlled by a next generation ULNB and shall not exceed 0.033 lb/MMBtu based on the higher heating value (HHV) (ARM 17.8.752 and Consent Decree).

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

7. Hydrogen Plant #3 (Reformers H-31A and H-31B)

   a. NO_x emissions from each heater shall be controlled by an ULNB and shall not exceed 0.051 lb/MMBtu based a 30-day rolling average (ARM 17.8.752).

   b. For process heaters (forced 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. 60 ppm_{vd} (corrected to 0-percent excess air) determined daily on a 30-day rolling average basis; or

      ii. 0.060 lb/MMBtu-HHV basis determined daily on a 30-day rolling average basis.

   c. Calumet shall control particulate matter (PM), PM with an aerodynamic diameter of 10 microns or less (PM_{10}), and PM with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$) emissions from each heater by utilizing good combustion practices and only combusting low sulfur fuels (ARM 17.8.752):

      i. PM/PM_{10} emissions shall not exceed 0.00051 lb/MMBtu based on a 30-day rolling average, and

ii. $PM_{2.5}$ emission shall not exceed 0.00042 lb/MMBtu based on a 30-day rolling average

d. Calumet shall control CO emissions using good combustion practices and CO emissions shall not exceed 0.03 lb/MMBtu based on a 30-day rolling average, or 17.6 tons per year based on a 12-month rolling average (ARM 17.8.752).

e. The combined carbon dioxide equivalent (CO_2e) emissions from the reformer heaters shall not exceed 133,038 TPY based on a 12-month rolling average (ARM 17.8.752).

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

8. #2 Crude Unit process heaters (H-2101, H-2102, H-4101, H-4102)

a. Each fuel combustion device must be equipped with an ULNB and NO_x emissions shall not exceed 0.035 lb/MMBtu-HHV based on a 30-day rolling average (ARM 17.8.752).

b. 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 ppm_{vd} (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.

c. 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 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.

d. 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 based on a 30-day rolling average, and

ii. $PM_{2.5}$ emission from each heater shall not exceed 0.00042 lb/MMBtu based on a 30-day rolling average.

e. 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, based on a 30-day rolling average (ARM 17.8.752).

f. 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 based on a 30-day rolling average for the Crude Heater (H-2101) and Vacuum Heater (H-2102).

ii. 141 lb/MMBtu based on a 30-day rolling average for the Combined Feed Heater (H-4101) and Fractionator Feed Heater (H-4102).

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

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

a. By November 11, 2015, or upon startup of the modified flare system, whichever is later, Calumet shall comply with the requirements of 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

b. Calumet shall not burn in any affected flare any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a 3-hour rolling average 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 (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

c. By November 11, 2015, or at startup of the modified flare system whichever is later, Calumet must develop, submit, and implement the flare management plan pursuant to 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

10. 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).

11. 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).

12. 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 (Consent Decree)

   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, corrected to 0% oxygen (O_2) 1-hour average (Consent Decree)

      iii. 100 ppmvd, corrected to 0% O_2 on a 365-day rolling average (Consent Decree)

d. SO_2

i. 50 ppmvd, corrected to 0% O_2, on a 7-day rolling average, except for periods of hydrotreater outages (Consent Decree)

ii. 25 ppmvd, corrected to 0% O_2, on a 365-day rolling average (Consent Decree)

e. NO_x

i. 87 ppmvd, corrected to 0% O2, on a 7-day rolling average, except for periods of startup, shutdown, malfunction or hydrotreater outages

ii. 68 ppmvd, corrected to 0% O2, on a 365-day rolling average

D. 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 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, in order to demonstrate compliance with the limit in Section II.B.20 (Consent Decree, 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 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, in order to demonstrate compliance with the limit in Section II.B.21 (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, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

2. SWSOH

a. Calumet shall comply with the monitoring requirements contained in 40 CFR 60, Subpart J (#1 and #2 Boilers) or Ja (#3 Boiler), during all times when the HTU SWSOH is incinerated in the #1, #2 or #3 Boilers. Calumet shall conduct either H_2S monitoring of the SWSOH stream to demonstrate compliance with the limit in Section II.B.16, or SO_2 stack monitoring for the #1, #2 and #3 Boilers to demonstrate compliance with 20 ppm (dry basis, zero percent excess air) SO_2, as approved by the Department, in writing (Consent Decree, ARM 17.8.340, 40 CFR 60, Subpart J (Boilers #1 and #2), and/or 40 CFR 60, Subpart Ja (Boiler #3)).

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

   a. SO_2 and O_2 (Consent Decree)

   b. NO_x and O_2 (Consent Decree)

   c. CO and O_2 (Consent Decree, 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)

4. Calumet shall install, certify, calibrate, maintain and operate the above-mentioned SWSOH 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 (Consent Decree).

5. 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).

6. Calumet shall install and operate an SO_2 and O_2 CEMS, and a volumetric flow rate monitor on the stack for the #3 Boiler, to be used as the primary analytical instrument to determine compliance with state and federal SO_2 requirements. Calumet shall initially certify the #3 Boiler SO_2/O_2 CEMS, and the volumetric flow rate monitor in accordance with 40 CFR 60, Performance Specifications 2, 3 and 6. After initial certification, Calumet shall conduct annual RATA of the #3 Boiler SO_2/O_2 CEMS and the volumetric flow rate monitor in 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 #3 Boiler SO_2/O_2 CEMS (ARM 17.8.749).

7. 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).

8. Once modified flare system is constructed, Calumet shall install, operate and maintain instrumentation for continuously monitoring the volumetric flow and sulfur content to the flare system (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

E. Emission Testing:

1. The FCCU shall be tested for CO and SO_2 and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.C.12.c and d. The testing shall occur annually or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.106).

2. Compliance with the FCCU PM emission limit in Section II.C.12.a shall be demonstrated by conducting a 3-hour performance test representative of normal operating conditions for PM emissions by December 31 of each calendar year. If any performance test undertaken pursuant this section is not representative of normal operating conditions, Calumet shall conduct a subsequent performance test representative of normal operating conditions by no later than 90 days after the test that was not representative (Consent Decree).

3. The #1 and #2 Boilers shall be tested for CO and NO_x, concurrently, and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.C.2. The testing shall occur on an every 2 year basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.106).

4. Calumet shall test the #3 Boiler for CO and NO_x concurrently, to monitor compliance with the emission limits and/or conditions contained in Section II.C.3. The initial performance source test must be conducted within 60 days of achieving the maximum production rate, but not later than 180 days after initial startup of the boiler. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105 and ARM 17.8.749).

5. All fuel combustion devices (Section II.C.7 and II.C.8) 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 and applicable testing requirements of Consent Decree (ARM 17.8.340 and Consent Decree).

6. 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.

7. 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.

8. 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.10 on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department. Calumet shall perform the test methods and procedures as specified in 40 CFR 63.425 (ARM 17.8.105 and 17.8.342).

9. 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.11.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 the Department. Calumet shall perform the test methods and procedures as specified in 40 CFR 63.425 (ARM 17.8.105 and 17.8.342).

10. 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.11.b and c within 180 days of initial startup (ARM 17.8.105).

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

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

13. The Department 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, in conjunction with metered refinery fuel gas usage (including SWSOH, if appropriate), data from the FCCU, the #1 and #2 Boiler SO_2 CEMS, the #3 Boiler SO_2 CEMS and stack testing data.

   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 #1 & #2 Boiler, #3 Boiler, FCCU, product loading VCUs, and any other stack tests conducted.

2. #1 and #2 Boilers

   a. Compliance with #1 and #2 Boiler SO_2 emission limitations contained in Section II.C.2.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 SO_2/O_2 CEMS or volumetric flow monitor is not operational, Calumet must (ARM 17.8.749):

      i. notify the Department 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 SWSOH to the NaHS unit;

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 the Department within 24-hours when the SO_2/O_2 CEMS is back on-line.

c. Compliance with the #1 and #2 Boiler NO_x emission limits contained in Section II.C.2.b shall be determined based on actual fuel burning rates and the emission factor developed from the most recent compliance source test.

d. Compliance with the #1 and #2 Boiler NO_x emission limit and the operational fuel usage limit contained in Section II.C.2.e shall be based on the most recent emission factors obtained through source testing and the monitored fuel gas consumption (RFG) (ARM 17.8.749).

e. Compliance with the #1 and #2 Boiler CO emission limits contained in Section II.C.2.c 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. #3 Boiler

a. Compliance with the #3 Boiler SO_2 emission limitations contained in Section II.C.3 shall be based on the data from the SO_2/O_2 CEMS (ARM 17.8.749).

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

i. notify the Department 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 SWSOH to the NaHS unit;

iv. repair and/or replace the SO_2/O_2 CEMS equipment and continue to monitor compliance as required in Section II.F.3;

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

c. Compliance with the #3 Boiler's NO_x emission limit in Section II.C.3 shall be demonstrated by conducting three, one-hour performance tests representative of normal operating conditions for NO_x emissions by December 31st of each calendar year. If any performance test undertaken pursuant this section is not representative of normal operating conditions, Calumet shall conduct a subsequent performance test representative of normal operating conditions by no later than 90 days after the test that was not representative. After three consecutive years of testing, Calumet may request that the Department re-evaluate the testing requirement provided Calumet has proposed adequate operating parameters for the unit that can be used as indicators of compliance (ARM 17.8.749 and Consent Decree).

d. Compliance with the #3 Boiler 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. Diesel/Gas Oil HDS Heater

Compliance determinations for NO_x and CO emission limits for the diesel/gas oil HDS heater 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.

b. Compliance with the NO_x emission limit in Section II.C.6 and II.C.7 for Hydrogen Plant #2 and Hydrogen Plant #3 (reformer heaters) shall be demonstrated by conducting three, one-hour performance test representative of normal operating conditions for NO_x emissions by December 31 of each calendar year. If any performance test undertaken pursuant this section is not representative of normal operating conditions, Calumet shall conduct a subsequent performance test representative of normal operating conditions by no later than 90 days after the test that was not representative. After three consecutive years of testing, Calumet may request that the Department re-evaluate the testing requirement provided Calumet has proposed adequate operating parameters for the unit that can be used as indicators of compliance (ARM 17.8.749 and Consent Decree).

c. Compliance with NO_x and SO_2 emission limits for Hydrogen Plant #3 reformer heaters (H-31A and H-31B) 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).

d. Calumet's shall submit all reporting and recordkeeping in accordance with the Greenhouse Gas Reporting Rule to demonstrate compliance with the CO_{2e} emission limits (ARM 17.8.749).

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.12 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, H-4101, H-4102)

   a. Compliance with the NO_x emission limit in Section II.C.8 shall be demonstrated by conducting three, one-hour performance test representative of normal operating conditions for NO_x emissions by December 31 of each calendar year. If any performance test undertaken pursuant this section is not representative of normal operating conditions, Calumet shall conduct a subsequent performance test representative of normal operating conditions by no later than 90 days after the test that was not representative. After three consecutive years of testing, Calumet may request that the Department re-evaluate the testing requirement provided Calumet has proposed adequate operating parameters for the unit that can be used as indicators of compliance (ARM 17.8.749 and Consent Decree).

   b. Compliance with 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.

G. Reporting and Recordkeeping Requirements:

1. Plant-wide Refinery

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

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

      - Refinery fuel gas: daily H_2S monitoring data and refinery fuel gas usage;

      - SWSOH: daily H_2S and SWSOH combustion amount, or SO_2 monitoring data from the #1 & #2 Boiler stack;

- SO_2 CEMS Data from FCCU, #1 and #2 Boiler, and #3 Boiler converted to daily mass emissions;

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

c. Identification of any periods of excess emissions or other excursions during the reporting period; and

d. Monitoring downtime that occurred during the reporting period.

2. #1 and #2 Boilers

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

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

- Hourly SO_2 CEMS data for the reporting period;
- Fuel gas H_2S analyzer data for the reporting the period;
- SWSOH – either the daily H_2S concentration and SWSOH combustion amount of the HTU SWSOH, or the #1 and #2 Boiler stack SO_2 concentration on a daily basis;

b. NO_x emission estimates for each month of the quarter. 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 of the quarter. The CO emission rate shall be reported as an hourly average;

d. Operating times for #1 and #2 Boilers and the HTU SWS unit during the reporting period;

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

f. Calumet shall maintain records of daily fuel usage (in MMscf/yr) in 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);

g. Identification of any periods of excess emissions or other excursions during the reporting period; and

h. Monitoring downtime that occurred during the reporting period.

3. #3 Boiler

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

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

- Hourly SO_2/O_2 CEMS data for the reporting period;
- Fuel gas H_2S analyzer data for the reporting the data;
- SWSOH – either the daily H_2S concentration and SWSOH combustion amount of the HTU SWSOH, or the #3 Boiler stack SO_2 concentration on a daily basis;

b. NO_x emission estimates for each month of the quarter. The NO_x emission rates shall be reported as an hourly average;

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

d. Operating times for #3 Boiler and the HTU SWSOH unit during the reporting period;

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

f. Identification of any periods of excess emissions or other excursions during the reporting period; and

g. 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 quarterly emission reports to demonstrate compliance with Section II.C.12 using data required in Section II.F.8. The quarterly report shall include the following (ARM 17.8.749):

a. Emission estimates for NO_x, SO_2 and CO, for each month of the quarter;

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. Identification of any periods of excess emissions or other excursions during the reporting period; and

f. Monitoring downtime that occurred during the reporting period.

7. All Emission Reports shall be submitted within 45 days following the end of the calendar quarter (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 the Department upon request (ARM 17.8.749).

H. Operational Reporting Requirements

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

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

2. Calumet shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include a change of control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or ***the addition of a new emission unit***. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include information requested in ARM 17.8.745(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 the Department, and must be submitted to the Department upon request (ARM 17.8.749).

I. Notification Requirements

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

2. Tank Construction

a. Notification of the actual start-up date of tanks #122, #123, #52, #49, #47, #48, #50, #102 within 15 days after the actual start-up of the unit.

3. #2 Crude Unit - Expansion Project

a. Notification of start of construction for each unit within 30 days after actual construction has begun;

b. Notification of the actual start-up date of each unit within 15 days after the actual start-up of the unit;

c. Notification of the start of construction of new and modified tanks associated with the #2 Crude Unit.

J. Ambient Monitoring

Calumet shall conduct ambient air monitoring as described in Attachment 1.

SECTION III: General Conditions

A. Inspection – Calumet shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (Continuous Emissions Monitoring System (CEMS) 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 the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of

Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department 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 18 months 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	AMBIENT AIR MONITORING PLAN

ATTACHMENT 1

AMBIENT AIR MONITORING PLAN
Calumet Montana Refining, LLC (Calumet)
Montana Air Quality Permit (MAQP) #2161-28

1. This Ambient Air Monitoring Plan applies to Calumet's crude oil refinery located at 1900 10th Street North East, in Great Falls, Montana. The Department may modify the requirements of this monitoring plan. All requirements of this plan are considered conditions of the permit.

2. The requirements of this attachment shall take effect within 30 days of permit issuance, unless otherwise approved in writing by the Department.

3. Calumet shall operate and maintain one air monitoring site northeast of the refinery. The exact location of the monitoring site must be approved by the Department and meet all the siting requirements contained in the Montana Quality Assurance Manual, including revisions, the EPA Quality Assurance Manual, including revisions, and 40 CFR Part 58, or any other requirements specified by the Department.

4. Calumet shall submit a topographic map to the Department identifying Universal Transverse Mercator (UTM) coordinates, air monitoring site locations in relation to the facility, and the general area present.

5. Within 30 days prior to any changes of the location of the ambient monitors, Calumet shall submit a topographic map to the Department identifying UTM coordinates, air monitoring site locations in relation to the facility, and the general area present.

6. Calumet shall continue air monitoring for at least 2 years after installation of the monitor described in Section 2 above. The Department will review the air monitoring data and the Department will determine if continued monitoring or additional monitoring is warranted. The Department may require continued air monitoring to track long-term impacts of emissions from the facility or require additional ambient air monitoring or analyses if any changes take place in regard to quality and/or quantity of emissions or the area of impact from the emissions.

7. Calumet shall monitor the following parameters at the site and frequencies described below:

   AIRS # 30-013-2001 Site Name – Race Track Site

UTM Coordinates	Code & Parameter	Frequency
Zone 12	42401 SO_2[1]	Continuous
N 5263700	61101 Wind Speed and Direction	"
E 478600	61106 Standard Deviation of Wind Direction (sigma theta)	"

   [1]SO_2= sulfur dioxide

8. Data recovery for all parameters shall be at least 80% computed on a quarterly and annual basis. The Department may require continued monitoring if this condition is not met. (Data recovery = (Number of data points collected in evaluation period)/(number of scheduled data points in evaluation period)*(100%)).

9. Any ambient air monitoring changes proposed by Calumet must be approved, in writing, by the Department.

10. Calumet shall utilize air monitoring and Quality Assurance (QA) procedures that are equal to or exceed the requirements described in the Montana Quality Assurance Manual, including revisions, the EPA Quality Assurance Manual, including revisions, 40 CFR Parts 50 and 58, and any other requirements specified by the Department.

11. Calumet shall submit two hard copies of quarterly data reports within 45 days after the end of the calendar quarter and two hard copies of the annual data report within 90 days after the end of the calendar year.

12. The quarterly data submittals shall consist of a hard copy narrative data summary and a digital submittal of all data points in AIRS batch code format. The electronic data must be submitted to the Air Monitoring Section as digital text files readable by an office personal computer (PC) with a Windows operating system.

    The narrative data hard copy summary must be submitted to the Air Compliance Section and shall include:

    a. A hard copy of the individual data points,

    b. The first and second highest 24-hour rolling and block concentrations for SO_2,

    c. The first and second highest 3-hour concentrations for SO_2,

    d. The first and second highest hourly concentrations for SO_2,

    e. The quarterly and monthly wind roses,

    f. A summary of data completeness,

    g. A summary of the reasons for missing data,

    h. A precision data summary,

    i. A summary of any ambient air standard exceedances, and

    j. Quality Assurance/Quality Control (QA/QC) information such as zero/span/precision, calibration, audit forms, and standards certifications.

13. The annual data report shall consist of a narrative data summary. The narrative data hard copy summary must be submitted to the Air Compliance Section and shall include:

    a. A topographic map of appropriate scale with UTM coordinates and a true north arrow showing the air monitoring site location in relation to the refinery and the general area,

    b. The annual average concentration for SO_2;

    c. The year's four highest 24-hour rolling and block concentrations for SO_2,

    d. The year's four highest 3-hour concentrations for SO_2,

    e. The year's four highest hourly SO_2 concentrations,

    f. The annual wind rose,

g. A summary of any ambient air standard exceedances, and

h. An annual summary of data completeness.

14. All records compiled in accordance with this Attachment 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 the Department, and must be submitted to the Department upon request (ARM 17.8.749).

15. The Department may audit (or may require Calumet to contract with an independent firm to audit) the air monitoring network, the laboratory performing associated analyses, and any data handling procedures at unspecified times.

16. The hard copy reports should be sent to:
    Department of Environmental Quality
    Attention: Air Compliance Section Supervisor

17. The electronic data from the quarterly monitoring shall be sent to:
    Department of Environmental Quality
    Attention: Air Monitoring Section Supervisor

Montana Air Quality Permit (MAQP) Analysis
Calumet Montana Refining, LLC
MAQP #2161-28

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:

#1 Crude Unit
- Vacuum Heater
- Crude Furnace

#2 Crude Unit
- Vacuum Heater (27 million british thermal units per hour (MMBtu/hr))
- Crude Heater (71 MMBtu/hr)

Catalytic Poly Unit
Fluidized Catalytic Cracking Unit (FCCU)
- FCCU Preheater
- FCCU Regenerator

Mild Hydrocracker Unit (MHC)
- Combined Feed Heater (54 MMBtu/hr)
- Fractionator Feed Heater (38 MMBtu/hr)

Catalytic Reformer Unit
- Reformer Heater
- Naphtha Heater
- Kerosene Heater
- Naphtha Hydrodesulfurization (HDS) Unit
- Kerosene HDS Unit

Alkylation Unit
- Deisobutanizer reboiler

Hydrogen Plants
- Hydrogen Plant Reformer #1
- Hydrogen Plant Reformer #2
- Hydrogen Plant Reformer #3 (Reformer H-31A & H-31B, each rated at 67 MMBtu/hr)

Hydrotreater Unit (HTU) Unit
Sodium Hydrosulfide (NaHS) Unit
Polymer-Modified Asphalt (PMA) Unit
- WT-1901 – wetting tank
- RT-1901 – reactor tank

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

Utilities

- Boilers #1 & #2
- Boiler #3
- Wastewater
- Cooling Towers

Storage Tanks, including:

- Heated Heavy Oil: #50, #55, #56, #102, #110, #112, #130, #132, #133, #135, #137, #139 #140, #160
- #145B and #122, Wastewater surge tank (installed in 2006)
- Light Oil: #52, #54, #58, #100, #101, #122, #123, #125, #126, #127
- Crude Oil: #124, #201, #202, #203
- Heavy Oil: #36, #47, #48, #49, #63
- Misc: Naphtha Tanks #57, #124 and #127; Heavy Oil Tanks #44, #45, #11; #2 Diesel Tank #116; Raw Diesel Tank #128; NaHS Product, Caustic Tanks #35; #8, #9, #115, Ethanol Tank #175

Flare System

- Primary Flare #1 – equipped with a caustic scrubber
- Secondary Flare #2 – back up to Flare #1

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 emissions 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 – Air Resources Management Bureau (Department) 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 the Department 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.

The Department issued Draft Modification #2161-11 on November 6, 1997, to address the permit changes that were requested by MRC. The Department 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.

The Department issued Preliminary Determination #2161-11 on November 26, 1997. The Department received comments from MRC on December 4, 1997, December 10, 1997, December 15, 1997, and December 30, 1997. The Department responded to these comments via faxes on December 8, 1997, December 11, 1997, and December 16, 1997. On December 23, 1997, the Department 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, the Department 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 4, 2001, the Department 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, the Department 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, the Department 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, the Department 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 the Department. MAQP #2161-15 replaced MAQP #2161-14.

On March 19, 2003, the Department 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.

The Department 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 the Department 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 the Department 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 current permit action updated the permit to reflect the changes. **MAQP #2161-17** replaced MAQP #2161-16.

On May 14, 2004, the Department 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, the Department added the fuel switch. The current permit action updated the permit to reflect these changes. **MAQP #2161-18** replaced MAQP #2161-17.

On May 17, 2007, the Department 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 SWSOH. 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, the Department received 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, the Department 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 the Department on April 21, 2008, where MRC proposed to change the operation of Storage Tank #8 from NaHS to naphtha. The Department reviewed this de minimis request and determined that MAQP #2161-20 must first be amended as described in the 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, the Department 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 the Department 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, the Department 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, the Department 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, the Department 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, the Department 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, the Department 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, the Department has clarified the permit language for the bulk loading rack VCU regarding the products that may be loaded in the event the VCU is inoperable and deleted all references to 40 CFR 63, Subpart DDDDD: NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters, as it was removed from the ARM in October 2008. The Department 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, the Department 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, the Department 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). The Department 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 the Department and to propose a NO_x permit limit for the heater. MRC submitted a permit application on December 29, 2009 and the Department deemed this application incomplete on January 15, 2010. On

July 12, 2010, MRC submitted additional information as requested by the Department. 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 (the #3 Boiler) capable of firing refinery fuel gas, SWSOH, or natural gas at the petroleum refinery. The primary purpose of the #3 Boiler is to supplement the two existing boilers (#1 and #2) that provide process steam to the refinery. The design burner heat input capacity for the #3 Boiler varies, depending upon fuel characteristics, from 59.7 to 60.5 MMBtu/hr. The Department deemed the application incomplete on August 4, 2011, and MRC provided additional information in response to the Department's letter on September 26, 2011.

On October 25, 2011, the Department requested additional information with respect to MRC's plantwide applicability limit (PAL) and the SWSOH combustion properties. This information was received by the Department 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 the #3 Boiler.

Therefore in addition to adding the #3 Boiler 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 SWSOH to the boilers. **MAQP #2161-25** replaced MAQP #2161-24.

On October 24, 2012, the Department 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, the Department 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

Current Tank ID	Current Service	Current Capacity (in barrels (bbl))	New Tank ID	Service	New Capacity (in bbl)
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.

D. Current Permit Action

On October 3, 2013, the Department received a permit application requesting a major modification under the NSR-PSD program. The application was considered significant for greenhouse gases (GHG) and volatile organic compounds (VOC). The application for MAQP #2161-28 was deemed complete on February 10, 2014.

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

The expansion project includes 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 specific emitting units included with the expansion project are as follows: Hydrogen Plant #3 (equipped with two heaters and a total combined firing rating of up to 134 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 secondary flare interconnected to the existing flare that will be equipped with a flare gas scrubber. With the expansion, Calumet also proposes 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 currently block operates in both diesel and gas-oil service will become the kerosene HTU, and the existing kerosene HTU will become a Naptha HTU. Lastly, Calumet requested a federally enforceable operational limit on Boiler #1 and Boiler #2.

E. Response to Public Comment

1. Comments received by Calumet.

Permit Reference	Comment	Department Response
Section I.B. Permitted Facility	The bullet point for Crude Oil and Gas-Oil Rail Car Loading Rack. This should be changed to asphalt/diesel loading and crude oil/gas oil unloading rack. This would be consistent with the language in Section 1.C, paragraph 4.	The Department has made the requested change.
Section II.A.1.j Limitations and Conditions	In the last line of the paragraph, replace "#2 Crude" with "Low Sulfur Fuels."	The Department has made the requested change.
Section II.B.2 Emission Control Requirements	Item #2 states that the #2 Flare shall not exceed 9 hours of operation based on a 12 month rolling average. Since the #2 Flare will have a continuous sweep gas purging the flare header and the pilots will be operated 100% of the time, CMR is suggesting that the language read as "Flare #2 (secondary flare) must maintain a water seal, except during periods of startup, shutdown and malfunction. The periods of startup, shutdown, and malfunction shall not exceed 9 hours per year based on a 12-month rolling basis (40 CFR 60, Subpart Ja and ARM 17.8.749."	The Department has updated the language of this condition.
Section II.C.12.e Emission Limitations	This paragraph states old language. Please update the NOx emissions limits to reflect 68 ppmvd on a 365 day rolling average and 87 ppmvd on a 7-day rolling average as established in a letter from EPA dated September 23, 2010, that was received by MDEQ on October 1, 2010. (OP2161-05)	The Department has updated the language of this condition to reflect the language from the September 23, 2010 EPA letter.

2. Comments received by the public.

The Department received comments in the form of a single letter which was arranged by paragraph. The Department has chosen to address the comments generally by paragraph in order to provide focused responses in the following table. In some cases the original content of the comment may be truncated, split, or otherwise edited in order to facilitate a focused response.

Permit Reference	Comment	Department Response
1. General comment	"All persons are born free and have certain inalienable rights. They include **the right to a clean and healthful environment…"** (emphasis added). The Constitution of the State of Montana, Article II, Section 3. Inalienable Rights. The citizens of Great Falls are having their right to a "clean and healthful environment"	Section V. of the MAQP Analysis for MAQP #2161-28 addresses the existing ambient air quality for Cascade County. It describes how as of July 8, 2002, all of Cascade County has been designated as an Unclassifiable/Attainment area for NAAQS for all criteria pollutants. The Department currently monitors for $PM_{2.5}$ in Great Falls for the purpose of supplying near real-time data for the Today's Air website

Permit Reference	Comment	Department Response
	denied. The air quality in Great Falls is currently NOT clean and NOT healthful and is likely to be even worse following the expansion of the local Calumet refinery from its current 10,000 BPD operation to a proposed 30,000 BPD operation. Residents of Great Falls, including members of our household, friends, and neighbors, routinely awake many mornings with red eyes and bleeding noses. Who is affected depends on the wind direction and strength. If there is almost no wind, many citizens in multiple areas of the Great Falls are affected because the emission spread over a broad area of the town that extends at least as far east as 38th street, north into Eagle's Crossing, south to the area across the river, and into the Westside. In the winter, when there is an inversion due to cold weather, the whole city ends up being covered by emissions from the refinery – from our house we can see the layer spreading from the refinery stacks. When an inversion exists, and we travel about town, we smell refinery emissions as we enter and exit businesses.	(http://svc.mt.gov/deq/todaysair/). There have been historical ambient air quality issues with CO in Great Falls and a small area along 10th Avenue South is a Maintenance Area from a former CO nonattainment designation. This is a high-traffic area and ambient levels of CO were monitored there at that time. However, Calumet's MAQP has contained facility wide CO emission limitations since 1985 that are designed to be protective of the ambient air quality standards. The MAQP has also had enforceable emission limits at the facility for SO_2 during this time, both plantwide and on the #1 and #2 boilers. These limits have been lowered throughout the passing years. The current emission limits were derived based on air dispersion modeling and where shown to protect the AAQS for SO_2. The facility is limited to 4.15 tons per day of SO_2 emissions. The facility has been required to operate an ambient SO_2 monitor since September 1994 to verify that the ambient air quality standards are not being violated. In a September 1999 permit action, MRC was required to move the ambient monitor location because it was shown to be inappropriate based on an air dispersion analysis. The current location is based on a modeling analysis and is designed to represent the location of worst-case ambient concentrations based on emissions information and local meteorological conditions.
2. Item 3 of Attachment 1 on page 30	According to Item 3 of Attachment 1 on page 30 of the permit, Calumet is only required to operate, "one air monitoring site northeast of the refinery." Given the distribution of refinery emissions as indicated in the previous paragraph of these comments, one air monitor seems completely inadequate. For the past three years there has been more south wind than is traditional for the area, rendering monitoring emissions northeast of the refinery of limited value. There should be additional monitoring sites located in other directions from the refinery facility. At our house, we routinely smell sulfur dioxide compounds – most notably when the wind is from the south. We are located approximately one mile directly north of the refinery and at an elevation that places us at nearly the same level as the emissions from the top of the various refinery stacks. We can personally verify that 'dilution is not the solution to pollution.' When we built at our location in 1985, the health-related issues we experience now only occurred rarely, in our opinion, because the refinery was operating	Please refer to the response to Comment #1 in regards to the ambient SO_2 monitor location. Reviews of the recent wind rose charts from the monitor that are submitted quarterly suggest that the winds are most typically out of the southwest. The reported levels of ambient SO_2 concentrations have not indicated any violations of the SO_2 AAQS. The most stringent of the SO_2 AAQS, the Federal 1-hour standard which became effective in 2010, has a limit of 75 parts per billion (ppb). The form of the design value for comparison with the 1-hour standard limit value is the 3-year average of the 99th percentile of the daily maximum 1-hr average, which must not exceed 75 ppb. The 99th percentile is roughly equivalent to the 4th-highest average hourly value. Since the promulgation of this more-stringent standard in 2010, even the single highest daily maximum 1-hour averages from those years are all less than 75 ppb.

Permit Reference	Comment	Department Response
	at a much lower (4000 BPD?) throughput. In case you are wondering, we are able to recognize the emissions and their source because we are both chemical engineers with extensive experience in refinery operations.	
3. MAQP Analysis Section I.C. Permit History	Through the intervening years leading to the filing for MAQP #2161-28, the refinery has steadily increased its throughput to the current 10,000 BPD by using numerous 'de minimis' requests to regulatory authorities such as the DEQ for changes to refinery operating parameters; this is partially documented in the historical section (I - c) of the MAQP Analysis for MAQP #2161-28 and especially noticeable on pages 8 – 10. For example, on page 10, the DEQ gave the refinery approval under the de minimis rule for a process heater with the heat input of 80 MMBtu/hr to facilitate the installation of a second hydrogen plant. This was not a minimal change to the refinery facility or its operation. It appears the local refinery has 'worked the system' through the de minimis rule to continually expand from a plant designed to process 2,500 BPD in 1923 to a 10,000 BPD facility in 2013. Despite the numerous de minimis changes made to the plant, the physical limitations of the original design are starting to become more apparent as indicated by more odors, more process flaring on the emergency flare (many citizens now think that flaring routinely is just part of normal refinery operation), and frequent operational problems. The restrictions on refinery operations under MAQP #2161-27, the current air quality permit, do not appear to be effective in preventing the refinery from creating local environmental and health issues. Now that the refinery wants to triple its thruput from 10,000 BPD to 30,000 BPD, the situation can only worsen because despite a huge increase in the potential for pollution associated with a tripling of thruput, very little is proposed in MAQP #2161-28 to make sure the current air quality situation is not worsened from what is obviously already bad. The BACT (Best Available Control Technology) solutions proposed as acceptable by the DEQ – require the refinery to install ultra low NOX burners (ULNB) and 'try to operate the best you can' - basically puts economics before the health of local citizens by not requiring the best pollution controls available for emissions.	Petroleum refining has been conducted at this site since the early 1920's which predates both the Federal and Montana Clear Air Acts by many decades. Montana Refining Company became subject to the Montana air permitting program in 1985 in order to establish enforceable limits on facility CO emissions. No form of the de minimis rule existed in the ARM at this time and any changes at a facility required the submittal of an application for a modification and the subsequent permitting process. In 1995, language that would eventually be used in the de minimis rule was formulated under ARM 16.8.705 *Malfunctions*, and ARM 17.8.1102 *When Permit Required – Exclusions* which made permit allowances for changes that did not result in an increase in of more than 15 tons per year of potential emissions of any pollutant. This language continued to evolve but consistently allowed for sources to modify or construct at a permitted facility without submitting an application for a permit modification provided that there was not an increase of more than 15 tons per year of potential emissions of any pollutant and that the change did not violate any applicable requirement of any statute, rule, or the state implementation plan. In 2002, ARM 17.8.745 *Montana Air Quality Permits – Exclusion for De Minimis Changes* was promulgated which is the same language as exists today except in 2010 the threshold was reduced from 15 tons per year to 5 tons per year. According to Calumet, the facility has undergone process optimization over time which has been the primary factor for increases in capacity. Process changes and new units (#2 hydrogen plant and MSAT-2 project) are associated with more stringent fuels requirements (sulfur and benzene reductions). The 80 MMBtu/hr process heater approved via the de minimis rule in 2008 was determined to have maximum potential emissions less than 15 tons per year of any pollutant and met the criteria for a de minimis change. ULNB are considered an appropriate pollution control practice to minimize the formation of NO_x emissions and are commonly required as BACT. The BACT analysis section of MAQP #2161-28 indicates that proposed NO_x emission limits are consistent with what is reported in the RACT/BACT/LAER Clearinghouse (RBLC), a

Permit Reference	Comment	Department Response
		database containing recent emission limits and control technologies required on major sources in the United States. Economic feasibility is an element of the BACT analysis in accordance with ARM 17.8.752 and ARM 17.8.819. The Department concurred with Calumet that the additional expense for relatively small additional NO_x reductions from add-on controls was not appropriate in this instance. The facility was not subject to Lowest Achievable Emission Rate (LAER) requirements for NO_x because this only applies to major modifications in nonattainment areas. Economic impacts are not considered in the control technology review in LAER situations, which do not apply to this scenario since Cascade county is unclassifiable/attainment with the NO_x AAQS. Failure to operate emitting units for which a permit is required to provide the maximum air pollution control for which it was designed is an enforceable violation of ARM 17.8.752.
4. General Comment related to ARM 17.8.110 and ARM 17.8.111	Based on past and current operation of the facility, citizens can not rely on refinery operations to be the best possible; past operations have not demonstrated even satisfactory operations and there is little reason to expect the operations to improve. For example, ARM 17.8.110 Malfunction requires that the 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 great than four hours" - recently Calumet experienced a problem with their wet gas compressor and flared heavily for over one and a half days without notifying the DEQ. Clearly Calumet was in violation of ARM 17.8.110 and by continuing to operate they were also in violation of ARM 17.8.111 which states "…No equipment may produce emissions, shall be operated, or maintained in such a manner as to create a public nuisance." Most refiners would have shutdown the offending unit for such a lengthy repair period.	On March 25, 2014, Calumet submitted email notification of a flaring event that is likely the situation described in the comment. The Department is currently reviewing the details of this incident. Calumet stated that during routine inspection the operators discovered that valves on the FCCU wet gas compressor were running hotter than normal. To prevent a catastrophic failure of the compressor, the charge to the FCCU was reduced to 1500 bpd (3000 bpd typical charge rate) and gases going to the wet gas compressor were flared. This allowed maintenance personnel to replace the valves and perform necessary maintenance. While flaring the gases was undesirable, it did allow maintenance activities to be performed without having to conduct an entire unit shutdown, which would have resulted in significantly higher emissions.
5. General comment regarding significant emission increases.	Calumet is only required to "operate and maintain one air monitoring site northeast of the refinery" (Attachment 1-Ambient Air Monitoring Plan, Item 3, page 30). This is clearly inadequate since the pollution is all over town not just to the northeast. The proposed air quality permit, MAQP #2161-28, is for a major modification to the Calumet facility in Great Falls. This permit represents that the modifications are significant for green house gases (GHG) and volatile	Please refer to the responses to comments #1 and #2 regarding the ambient monitor. The term "significant" has specific regulatory meaning in this context as defined in ARM 17.8.801(28). It refers to a net emission increase in excess of established emission rates in units of tons per year. This permit action represents a net emissions increase in excess of the significant emission rate defined in ARM 17.8.801(28) for VOC, but not for SO_2 or

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	organic compounds (VOC) but places little emphasis on sulfur and particulate emissions, which are significant as well. In February 2014, with DEQ personnel in attendance, Calumet represented to the public that a MHC Unit was for sulfur compound control in final products. On page 2 of the proposed MAQP #2161-28, it states, 'four new processing units: a MHC for gas-oil conversion to higher value distillates'. Conversion and sulfur removal are two different, related issues. Before discussing the actual proposed permit language, there needs to be clarification about what the actual reason is for the addition to the refinery facility. The refinery wants to generate more revenue by increasing the processing of additional crude oil and outside gas oil and simultaneously needs to upgrade the quality of their fuels products by reducing sulfur levels. More sulfur removal will require more treating capacity for sulfur compounds like H2S. The proposed MHC appears to be of a size that could not be fed from feedstock generated from 30,000 BPD of crude processing capacity. Additional gas-oil feedstock for the MHC would be required; that additional feedstock is hinted at in the addition of a new rail car 'unloading (crude oil and **gas oil**) area'. The source, quantity, and quality of this shipped-in gas oil is unknown and unspecified in the permit. This is a major deficiently in MAQP #2161-28 because the gas oil may ultimately determine the additional pollutants/emissions released by the refinery. The gas oil quality could be a significant issue for the fuel gas system because it could result in high levels of H2S in that system…	particulate emissions. GHG are not included in ARM 17.8.801(28); however, the federal significant emission rates for GHG are any net emission increase of combined GHG's on a mass basis and a net increase of more than 75,000 tons per year of carbon dioxide equivalent (CO_2e). Both sulfur (in the form of SO_2) and particulate emissions, while not considered significant by the ARM 17.8.801(28), were still subject to BACT review in accordance with ARM 17.8.752 and addressed in the Permit Analysis of MAQP #2161-28. Maximum potential SO_2 emissions from this project are relatively small (about 22 tons per year or 0.06 tons per day) based on the requirement to use inherently low sulfur fuels; therefore, add on pollution control technologies were not deemed to be appropriate. The fuel combustion devices associated with this project are subject to 40 CFR 60, Subpart Ja which includes SO_2 emission limits. Particulate emissions from this project are very minimal (approximately 1 ton per year) based on the inherently low particulate formation with these fuels. Additional pollution controls beyond good combustion practices are not warranted with maximum potential emission this low. All sulfur that is removed while processing crude oil ends up in the refinery fuel gas system. The refinery fuel gas is scrubbed with caustic in the NAHS, SCT, and SCS process units, for NSPS Subpart Ja compliance. The permit has many conditions requiring the use of low sulfur fuels in combustion units and/or SO_2 emission limits. Many emitting units require the use of SO_2 CEMS to monitor emission levels. The Department believes these conditions are protective of AAQS.
6. Section 2.B.2 on page 4	…Calumet recently has been controlling the level of H2S in the fuel gas system by flaring. Under the existing permit, MAQP #2161-27, Calumet does not have the authority to operate the emergency flare in this manner. However, in the middle of page 21 of the analysis section, it states: "Low pressure flare gas from normal operations will continue to be routed to the existing primary flare." Further, with an expansion to 30,000 BPD of crude processing, Calumet will no longer be able to take advantage of the exemption for small (below 10,000 BPD) refineries and avoid the requirement specified under ARM 17.8.322 for maximum levels of sulfur in fuel gases.	The language in the BACT Analysis discussion on page 21 of the draft MAQP #2161-28 stating that, "Low pressure flare gas from normal operations will continue to be routed to the existing primary flare" is not intended to imply that Calumet may use Flare #1 as a process flare for controlling H_2S. Calumet proposed to upgrade their emergency flare capacity to accommodate the larger flare gas scenarios that could occur after refinery expansion. Their proposal is to install a secondary emergency flare (Flare #2) that will be staged in series with the existing primary emergency flare (Flare #1). The secondary flare supply line between the flares will be blocked with a water seal to maintain flare gas flow to the primary flare. The water seal will be bypassed when the secondary

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	Progressing to looking at the actual proposed MAQP #2161-28 language, in Section 2.B.2 on page 4, Calumet is required to equip the current emergency flare (Flare #1) with a flare gas scrubber and limit operation of the new flare (Flare #2) to no more than 9 hours per year. This plus the information on page 21 mentioned in the previous paragraph seems to imply that Flare #1 is going to become a process flare since operations of an emergency flare with a flare gas scrubber is incredibly difficult. Given that the existing Flare #1 is already being operated like a process flare, the quantity of flare gas with a tripling of refinery thruput is likely to be much higher, exceeding the capacity of Flare #1, and could result in substantially more than 9 hours of flaring operation per year for Flare #2.	emergency flare is needed. A flaring event that is within the capacity of Flare #1 is what is described as "low pressure flare gas" in the sentence in question. When flare gas pressure is high enough to warrant the bypassing of the water seal, Flare #2 will receive the excess flare gas. Calumet is already required by Consent Decree and 40 CFR 60, Subpart J as presented in permit condition II.B.20 of MAQP #2161-28 to not combust any fuel gas with an H_2S concentration in excess of 230 mg/dscm equivalent to 0.10 gr/dscf, which renders moot the small refinery exemption offered under ARM 17.8.322. Upon refinery expansion, the facility will be subject to 40 CFR 60, Subpart Ja which contains even more stringent H_2S concentration limits and applies to the flare system as described in permit condition II.C.9.b.
7. Section 2.B.8 on page 6	Section 2.B.8 on page 6, states "all pressure vessels in HF acid service, except storage tanks, shall be vented to the flare system." Depending on the configuration of the Alkylation Unit, some vessels may need to vent through a caustic scrubber to prevent corrosion in the flare system.	This condition was not established as part of the current permit action and the Department does not have authority to modify this condition during this action. Calumet caustic scrubs all gases in HF acid service prior to being released to the flare header.
8. Section 2.B.10.b on page 7	Section 2.B.10.b on page 7, requires "all pumps in the PMA unit shall be equipped with standard single seals" – single seals should be a minimum requirement.	This condition was not established as part of the current permit action and the Department does not have authority to modify this condition during this action. Condition II.B.10.b requires the use of single seals and a source is not out of compliance if they go beyond BACT requirements; therefore, the implication is that single seals are a minimum requirement.
9. Section 2.B.18.b on page 8	Section 2.B.18.b on page 8, states "in the event that the VC Unit is inoperable, Calumet may continue to load distillate." There are no time limits specified in this paragraph for how long the Vapor Combustion Unit can be out of commission. This statement, as currently written, would allow Calumet to operate long term without an operable VC Unit.	This condition was not established during the current permit action and the Department does not have authority to modify this condition during this action. The condition contains additional language not included in the comment which states that "…In the event that the VCU is inoperable, Calumet may continue to load distillates with a Reid vapor pressure of less than 27.6 kilopascals, provided the Department is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.752)." A petroleum distillate or blend having a Reid vapor pressure of 27.6 kilopascals or greater is the definition of gasoline from 40 CFR 63, Subpart CC. The complete condition from Section II.B.18.b prohibits the loading of gasoline without an operable VCU and requires the reporting of an inoperable VCU in accordance with ARM 17.8.110 *Malfunctions*. The loading of distillates with a Reid vapor pressure of less than 27.6 kilopascals via loading racks is not subject to emission control requirements of federal

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		regulations applying to gasoline loading racks. During 2013, Calumet loaded approximately 41,000,000 gallons of distillates. Using EPA AP-42 emissions calculation methodologies, this resulted in 341 lbs of VOC emissions (uncontrolled). Based on this data, distillate loading operations are considered to be an insignificant operation.
10. Section 2.B.18.f.iii on page 8	Section 2.B.18.f.iii on page 8, only requires Calumet to check tank tightness "within two weeks after the corresponding cargo tank is loaded" – no truck tanker should be loaded until its tightness has been verified.	This condition was not established during the current permit action and the Department does not have authority to modify this condition during this action. Vapor tightness certification for tanker trucks and railcars are kept in a computerized fuel loading system. This permit condition likely predates the computerized tracking of the certifications.
11. Section 2.B.19.g.iii on page 10	Section 2.B.19.g.iii on page 10, only requires Calumet to check tank tightness "within two weeks after the corresponding cargo tank is loaded" – no rail tanker should be loaded until its tightness has been verified.	This condition was not established during the current permit action and the Department does not have authority to modify this condition during this action. Vapor tightness certification for tanker trucks and railcars are kept in a computerized fuel loading system.
12. Section 2.B.19.l on page 11 Section 2.B.18.j on page 9	Section 2.B.19.l on page 11, states the VCU stack exit for railcar loading must be at least 30 ft above grade – this is inconsistent with Section 2.B.18.j on page 9, which requires the truck loading VCU stack to be at least 35 ft above grade. Note that Section 2.B.18.j does not refer to stack exit.	These conditions were not established during the current permit action and the Department does not have authority to modify them during this action. The truck loading VCU and railcar VCU are two separate emitting units with independent exhaust stack heights.
13. Section 2.B.23 on page 11	Section 2.B.23 on page 11, mentions, "the #1 Crude Unit stack height shall be 150 ft above ground level" – please clarify if this is the vent from the Vacuum Unit or something else. The emissions from this stack are dependent on the Vacuum Unit design – are there any details on emissions?	This condition was not established during the current permit action and the Department does not have authority to modify this condition during this action. The stack height requirement applies to the #1 Crude Unit process heater and not from a vent from the Vacuum Unit. The 150-foot stack height requirement was based on modeling of SO_2 emissions before sulfur recovery was installed at the refinery. In 2013, Calumet reported 4.8 TPY of CO, 19.4 TPY of NO_x, 1.1 TPY of PM, 1.2 TPY of SO_2, and 0.4 TPY of VOC from the Crude Furnace stack.
14. Section 2.C.1 on page 11	In Section 2.C.1 on page 11, the plant wide refinery emissions are shown as being limited for SO2 to 1515 tons per year or 4.15 tons per day and for CO to 4700 tons per year or 12.9 tons per day – these are huge numbers and will not have only a minor effect on human health as represented in the permit! If local citizens are already experiencing environmental and health issues from the current levels of emissions, increased level of emissions could make the surrounding areas nearly inhabitable.	The plantwide emission limits referred to are existing limits that are unchanged with this permit action. They do not represent the increase in emissions from this permit action. The CO limits have been in place since 1985 and the referenced SO_2 limits since 2002. The origin of these limits is documented in the Permit History section of the Permit Analysis. Actual reported emissions from Calumet have been substantially less than these maximum permitted levels during recent years. For example, in 2013 Calumet reported 46.3 tons per year of SO_2 and 57.1 tons per year of CO. In 2012 Calumet reported 17.1 tons per year of SO_2 and 46.0 tons per year of CO. In 2011 Calumet reported 17.3 tons per year of SO_2 and 48.4 tons

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		per year of CO. The maximum potential emissions from the new equipment from this permitting action for SO_2 are 21.20 tons per year or 0.06 tons per day. The maximum potential CO emissions increase is 73.43 tons per year or 0.20 tons per day. Comments in the permit related to minor effects on human health pertain to the impact from the emissions associated with this permit action.
15. Section 2.C.2 & 3 on page 11	In Section 2.C.2 & 3 on page 11, there is a discussion about boiler emissions – our understanding was that Boiler #3 was going to replace Boilers #1 and #2 – this does not appear to be indicated in this section. In addition, during the cold spells experienced this past winter season Calumet routinely operated all three boilers as indicated by visible emissions from the old stack and the new stack. Presumably, more steam generation capacity will be needed after the expansion to 30,000 BPD that currently. If emission credit is being given in the permit calculations for reduced operation or shutdown of old Boilers #1 and #2, and future operations necessitates using Boilers #1 and #2, the increase of emissions might not be included in MAQP #2161-28.	Calumet has previously declared that they intend to replace the capacity of Boilers #1 and #2 with the new Boiler #3. Calumet wishes to maintain the ability to operate Boilers #1 and #2 on a limited basis rather than remove them completely from service for times when Boiler #3 is down for maintenance. It is an accurate statement that MAQP #2161-28 does not allow for operation of Boilers #1 and #2 beyond the limitations described in Section II.C.2.e once the #2 Crude Unit is complete. If future operations require Calumet to increase their reduced operation limitations for Boiler #1 and #2, they would be required to go through the permitting processes of Subchapter 7 and potentially Subchapter 8.
16. Section 2.C.12 on page 17	Section 2.C.12 on page 17, referring to FCC Unit operation states 50 ppm of SO2 on a 7 day rolling average is allowed except when the hydrotreater (MHC?) is not in operation. Does this mean the FCC Unit is allowed to operate with unlimited SO2 emissions short-term when the hydrotreater (MHC?) is shutdown? The permit's intentions need to be clarified.	This condition is not related to the current permit action and the Department does not have authority to modify this condition during this action. The FCCU is not subject to a unit-specific short term SO_2 limit during hydrotreater outages; however, the facility is subject to the plantwide 24-hour SO_2 limit of 4.15 tons at all times.
17. Section 2.D.2 on page 17	For Section 2.D.2 on page 17, please clarify why there are no monitoring requirements listed for SWSOH.	This was an error in document formatting. The monitoring requirements for SWSOH are described in what was formerly numbered Section II.D.3. The numbering has been corrected to associate the SWSOH monitoring requirements as Section II.D.2.a and the remaining items in that section have been renumbered accordingly.
18. Section 2.E.4, 8, & 9 on page 19	Section 2.E.4, 8, & 9 on page 19, refers to emission testing on boiler #3, gasoline truck loading rack VCU, and gasoline railcar loading rack VCU on an every two year, or every five year, or every five year basis, respectively – this is too long an interval for testing to make sure the system is operating correctly until there is an established history of emissions. After the initial source testing, emissions should be tested on an annual basis for at least five years after which the frequency of testing could be reduced as	These conditions were not established during the current permit action and the Department does not have authority to modify these conditions during this action. Each new emitting unit subject to source testing must undergo an initial source test within 180 days after initial startup to verify operation as presented in the permit application and to demonstrate compliance with emission limitations. Subsequent source test frequency is determined based on Department policy and maximum potential uncontrolled emissions from the emitting unit. The testing

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	justified by the historical results.	frequency applied to these units is consistent with Department policy and other similar permitted units.
19. Section 2.F.3.v on page 21	Section 2.F.3.v on page 21, refers to compliance for SO2/O2 emissions monitoring equipment. In this section the time limit is missing for notifying the DEQ when problems with the CEMS have been corrected. The emissions monitoring equipment should not be out of commission indefinitely.	The commenter is correct in pointing out the error in the referenced permit condition that is missing the time limit for notifying the Department when the SO_2/O_2 CEMS is back on-line. The time limit should be 24 hours. This condition has been corrected.
20. Section 2.I on page 27	Section 2.I on page 27, Item 2, refers to notification requirements for startup of Boiler #3. Boiler #3 started up in 2013.	Calumet submitted the required notifications for Boiler #3. The Department has removed these conditions.
21. Item 8 of Attachment 1 on page 30	According to Item 8 of Attachment 1 on page 30, data recovery from ambient air monitoring is only required for at least 80% of the potential data points on a quarterly and annual basis. This percentage requirement is far too low and provides the opportunity for monitoring to NOT occur when emissions are known to be high. A third party should be responsible for maintaining, operating, collecting data, and reporting data for the air monitoring equipment to ensure impartiality.	The requirement for a minimum of 80% data recovery is consistent with and even more stringent than typical data recovery requirements for ambient monitoring stations. While it is true that ambient monitor downtime could coincide with periods of high emissions from Calumet, Calumet has requirements to operate CEMS on emitting units to monitor compliance with emission limits which are designed to be protective of AAQS. Calumet does currently contract with a third party for the calibration, operation, maintenance, data capture, and report preparation for their air monitoring site.
22. Page 2 of the Analysis Section	On page 2 of the Analysis Section, the source description states that the refining operations have been conducted at this site since 1920; the original refinery was built in 1923.	According to the Calumet Montana Refining webpage, the facility was under the ownership of American Refining Company in 1922 but does not provide a date of construction. The language in the Source Description has been updated to state that refining has been conducted at this site since the early 1920's, which the Department considers to be of adequate historical accuracy for its intended purpose.
23. Page 25 of the Analysis Section	On page 25 of the Analysis Section, there is a table showing the proposed BACT NOX emission limit for the six new heaters (equipped with ULNB) as ranging from 0.035 to 0.051 lb/MMBtu based on the vendor guarantees. This range is significantly higher than the 0.019 lb/MMBtu limit shown for #3 Boiler emissions on page 12 of the proposed permit. Why?	A BACT analysis is influenced by, but beholden to, previous BACT determinations for similar units. A BACT analysis is performed on a case by case basis for each emitting unit subject to review. The various heaters mentioned in the comment would combust different variations or mixtures of natural gas, refinery fuel gas, SWSOH, or PSA purge gas. The heaters are not all identical in capacity or function. While each of these combustion sources is required to utilize ULNB, there are various burner configurations that are referred to by this term. Calumet presented vendor guarantees for the NO_x emissions from the various heaters that were consistent with other BACT emission limits on similar sources based on a review of the RBLC.
24. General comment	MAQP #2161-28 should include current area-wide heart attack and cancer statistics as a reference point to study if the refinery thruput increases and the resulting additional hazardous emissions have any affect on these	The analysis of health risks due to pollutant exposure are reflected in the establishment of ambient air quality standards. The air permitting program is designed to be protective of the ambient air quality standards and individual air

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	statistics.	quality permits establish conditions and requirements on individual sources to ensure they do not violate these standards. The inclusion of current area-wide heart attack and cancer statistics in an air quality permit is beyond the scope of the air permitting program as prescribed by federal and state statute and rule.
25. General comment	No attempt has been made in these comments to evaluate the permit's response to green house gases (GHG). However, on page 29 of the analysis, the amount of GHG generated by this expansion project is listed as 243,797 tons per year, which puts the quantity of GHG above the 75,000 TPY threshold for what is considered a major emitter. The GHG BACT analysis offers little to reduce this GHG tally except for "good combustion practices". The bottom paragraph on page 29 tries to represent that much of this GHG does not really exist because it involves crude oil feedstock entering the refinery and leaving as products. Crude oil and products are not part of the 243,797 TPY GHG emissions from this proposed expansion. The primary emission source for GHG is the six new process heaters required for the expansion.	The primary sources of GHG emissions from this permit action are indeed from the combustion of hydrocarbon fuels in the six new process heaters required for the expansion. The statement referenced in the comment regarding carbon inputs and outputs at a refinery is intended to describe how a portion of the carbon present in the crude oil feedstock is converted into CO_2 during various combustion processes at a refinery; however, the majority of the carbon present in the crude oil feedstock is contained in the produced liquid fuel products that are sold to market. GHG is a relatively new pollutant subject to regulation and there are not yet available many demonstratively feasible technologies to reduce emissions to the atmosphere. Capture and sequestration is technologically and economically infeasible for this project. Good combustion practices are the current best approach to minimize the formation of GHG.
26. General comment	An expansion of the refinery crude oil run from 10,000 to 30,000 BPD is only acceptable if NO additional release of pollutants is generated from the expansion. The proposed best available technology (BACT) will not lead to the lowest level of emissions possible and will result in significant additional environmental pollution because the BACT decisions were basically all based on economic issues.	As discussed in the response to comment #1, Cascade County is designated as unclassifiable/attainment with all AAQS. As discussed in the response to comment #3, only areas which are designated as nonattainment with AAQS require the application of Lowest Achievable Emission Rate (LAER). LAER is defined in ARM 17.8.901(10) and generally means the most stringent emission limit that can be achieved. A facility subject to LAER must also achieve emissions offsets from other sources within the nonattainment area in order to obtain an air quality permit. Again, Cascade county is not a nonattainment area and therefore sources operating within it are not subject to LAER. A BACT analysis is defined in ARM 17.8.740(2) and ARM 17.8.801(6) and generally means an emission limitation based on the maximum degree of reduction of a pollutant which the Department, on a case by case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable. The Department considers the BACT emissions limits and control technology requirements to be

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		adequate and consistent with similar permitted sources, and MAQP #2161-28 to be protective of the AAQS.

F. Additional Information

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

II. Applicable Rules and Regulations

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

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

1. ARM 17.8.101 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment, including instruments and sensing devices, and shall conduct tests, emission or ambient, for such periods of time as may be necessary, using methods approved by the Department. 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 the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., MCA.

4. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., MCA.

5. 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 the Department upon request.

6. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

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

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. ARM 17.8.304 Visible Air Contaminants. (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. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions 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. Calumet is a small refinery (under 10,000 BPD crude oil charge) and is, therefore, exempt from this rule, provided that they meet the other provisions of this rule.

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. Calumet is subject to this rule when Calumet's normal processing exceeds 7,000 bbl/day of crude charge.

7. ARM 17.8.340 Standard of Performance for New Stationary Sources. This rule incorporates, by reference, 40 CFR Part 60, NSPS. 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, 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 Insitutional Steam Generating Units for which construction, modification, or reconstruction is commenced after June 9, 1989. This Subpart would apply to the #3 Boiler.

   c. Subpart J – Standards of Performance for Petroleum Refineries. This Subpart applies to facilities that are constructed or modified after June 11, 1973; therefore, new and modified fuel gas combustion devices will be subject to the provisions of Subpart J. In addition, the following shall apply, as described per the Consent Decree:

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

   d. Subpart Ja – Standards of Performance for Petroleum Refineries for which Construction, Reconstruction or Modification Commenced After May 14, 2007. This Subpart applies to fuel combustion units (heaters and flares) that are constructed or modified after May 14, 2007.

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

Note: The five tanks used in the PMA unit, listed below, are exempt from the provisions of Subpart Kb because the true vapor pressure (TVP) of the Volatile Organic Liquid (VOL) stored is less than 3.5 kilopascals (Kpa) (0.5076 pounds per square inch atmosphere (psia)).

Tank	PMA Unit Capacity	TVP (psia)
WT-1901 wetting tank	800 gal	negligible
RT-1901 reactor tank	715 bbl	negligible
asphalt storage (3)	1,000 bbl	negligible

f. 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.

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 – Equipment Leaks of VOC in Petroleum Refineries shall not apply to the following units:

Equipment	Year of Mfg.	Year of Install.
HF Alkylation Unit	1960	1990

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 exempt, this 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 #2 Crude Unit -expansion project.

k. Subpart QQQ – VOC Emissions from Petroleum Refinery Wastewater Systems does not apply to the following units:

Equipment	Year of Mfg.	Year of Install.
HF Alkylation Unit	1960	1990

l. All other applicable subparts and referenced test methods.

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

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

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

c. Subpart CC – NESHAP Pollutants from Petroleum Refineries shall apply to, but not be limited to, the bulk loading racks.

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

e. 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.

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

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

2. ARM 17.8.402 Requirements. 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:

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

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

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

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

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

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

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

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

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, modification or use of a source. Calumet submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. Calumet submitted an affidavit of publication of public notice for the September 27, 2013 issue of *Great Falls Tribune*, a newspaper of general circulation in Great Falls, Montana in Cascade County, as proof of compliance with the public notice requirements.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this Permit Analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving 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*.

10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or modified source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to the Department.

15. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to the Department for incineration facilities subject to 75-2-215, MCA.

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

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

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and 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).

   This permit modification is considered a major modification as defined in ARM 17.8.801(20) because it would result in a net emission increase greater than the significance levels for GHG and VOC.

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

1. 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:

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

   a. PTE > 100 TPY of any pollutant;

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

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

2. 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 #2161-27 for Calumet, the following conclusions were made:

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

   b. The facility's PTE is greater than 10 TPY for any one HAP and greater than 25 TPY of all HAPs.

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

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

   e. This facility is subject to current NESHAP standards (40 CFR 63, Subparts A, R, CC, UUU, EEEE, ZZZZ).

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

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

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

   Based on these facts, the Department determined that Calumet is a major source of emissions as defined under Title V. Calumet's current Title V Operating Permit (OP), #OP2161-08 which became final on January 10, 2014.

   Additionally, on July 30, 2013, Calumet submitted an application for modification to the MAQP and the OP. The Department issued Title V OP #OP 2161-09 as decision on March 11, 2014 and is scheduled to go final on April 11, 2014.

   Calumet did not submit a concurrent Title V Operating Permit Application with this permit action, but pursuant to ARM 17.8.1205, Calumet is required to file a complete application for an air quality operating permit within 12 months after commencing construction.

III. BACT Analysis[1]

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

With this permit action, Calumet plans to increase the low sulfur fuels capacity at the refinery from approximately 10,000 barrels per service day (bpsd) throughput up to 30,000 bpsd while increasing yields of distillates, kerosene, diesel, and asphalt products. Calumet is defined as a major source under the Federal Clean Air Act (FCAA), and the proposed expansion project will increase VOC and GHG emissions in excess of PSD significance thresholds and therefore is subject to NSR-PSD review.

The heavy sour crude will be received via pipeline and railcar and stored in crude feed tanks before being routed to a new 20,000 BPSD crude distillation unit (#2 Crude Unit). The #2 Crude Unit will be configured with a preflash drum to reduce atmospheric heater duty; an atmospheric distillation column for separation of naphtha, kerosene, and diesel; and a vacuum distillation tower for separation of various gas oils and residual. The naphtha and kerosene will be routed to intermediate tankage for feed to other existing processing units. Diesel and gas oils will be routed to intermediate tankage and then processed in the new MHC.

The MHC uses hydrogen (produced in the proposed new hydrogen plant to remove sulfur from the product. The hydrogen is reacted with the sulfur to create hydrogen sulfide (H_2S). The H_2S is caustic scrubbed from the refinery fuel gas system. The processed diesel from the MHC will meet Ultra Low Sulfur Diesel (ULSD) specifications. The new MHC converts some gas oil to diesel and naphtha. The unconverted gas oil is processed in the Fluid Catalytic Cracking (FCC) Unit. The cat gas from the FCC will be low enough in sulfur to meet the projected Tier III sulfur standards.

A new hydrogen plant (#3 Hydrogen Plant) will be required to meet the hydrogen consumption demands of the new MHC. The new hydrogen plant heaters will combust a mixture of PSA tail gas and pipeline quality natural gas. The PSA tail gas has a lower heating value of approximately 231 MMBtu/hr and must be mixed with some natural gas for combustion.

The flare gas system will be revamped by adding a second staged flare. A water seal will be added to the flare gas header. Low pressure flare gas scenarios from normal operations will continue to be routed to the existing primary flare. During high pressure or high flow startup, shutdown, and malfunction (SSM) events, the flare gas will vent through the water seal to the secondary flare. The proposed secondary emergency flare will only receive flow in cases where the volume exceeds the capacity for the existing flare.

The main units discussed in the BACT analysis are as follows: Hydrogen Plant #3 (equipped with two heaters and a total combined firing rating of up to 134 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. Additionally, Calumet 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.

Calumet reviewed all available control technologies, and control options that were not technically feasible for the specific project were removed from the list. The technologies that are considered

[1] Calumet's BACT Analysis, submitted October 3, 2013 through January 3, 2014 - summarized by the Department

technically feasible are then ranked in order of their effectiveness. Unless it is demonstrated that the energy, environmental, and/or economic impacts eliminate the most effective control technology, that technology is considered BACT. Upon careful and considered elimination of the most effective control option, (based upon energy, environmental, and/or economic considerations), the next most effective alternative is evaluated in the same manner. This process continues until a final control technology is selected and hence, considered BACT.

The BACT evaluation process can be summarized as follows:

- Identify potential technologies for each pollutant for each emission unit;
- Eliminate the technically infeasible control technologies;
- Determine emission reduction potential for the remaining controls and rank them;
- Evaluate the costs, energy consumption, and any environmental impacts of the remaining control technologies, starting with the most effective control technology
- Evaluate the ranked controls based on energy, environmental, and/or economic considerations; and
- Select the most effective option that is not rejected because of costs, energy consumption, or environmental impacts.

A. EXTERNAL COMBUSTION SOURCES

The proposed project design includes the following process heaters (most will be fired on natural gas and/or refinery fuel gas unless otherwise noted):

#2 Crude Unit
Crude Heater (H-2101) - 71 MMBtu/hr
Vacuum Heater (H-2102) - 27 MMBtu/hr

Mild Hydrocracker (MHC)
Combined Feed Heater (H-4101) -54 MMBtu/hr
Fractionator Feed Heater (H-4102) - 38 MMBtu/hr

Hydrogen Plant #3 (natural gas combustion and PSD off gas)
Hydrogen plant consists of two reformer heaters (H-31A and B) with a total combined capacity of 134 MMBtu/hr.

The primary pollutants of concern from external combustion sources include $PM/PM_{10}/PM_{2.5}$, NO_x, SO_2, CO, and VOC. The generation of these primary and secondary pollutants is directly related to fossil-fuel characteristics and combustion practices. The potential for generating CO, VOCs, and PM increases with decreasing combustion efficiency. This analysis will include pre- and post-combustion control technologies for the control of each primary air pollutant.

Calumet completed and provided with the application a detailed search of the EPA's RACT/BACT/LAER (RBLC) database. The following table summarizes the data used in the BACT analysis that follows.

RBLC Data			Proposed Project	
Pollutant	Control Equipment	Emissions (lb/MMBtu)	Control Equipment	Emission Rate
Small Boilers (70 – 120 MMBtu/hr) - RFG			Crude Heater (71 MMBtu/hr)	
CO	ULNB/GCP	0.06-0.12	ULNB	0.055 (vendor)

RBLC Data			Proposed Project	
Pollutant	Control Equipment	Emissions (lb/MMBtu)	Control Equipment	Emission Rate
NO_x	ULNB	0.003-0.09	ULNB	0.035 (vendor)
PM_{10}	Combust clean burning fuel	0.0075	Combust clean burning fuel	0.00051 (EPA)[2]
$PM_{2.5}$	Combust clean burning fuel	0.0075	Combust clean burning fuel	0.00042 (EPA)
SO_2	RFG – sulfur removed	Subpart Ja	RFG – sulfur removed	Subpart Ja
VOC	Gaseous fuel combustion only	0.005	Gaseous fuel combustion only	0.03 (Webfire)
Small Boilers (9.6 – 64.2 MMBtu/hr) - RFG			Vacuum, Combined feed, Frac. Feed Heater (27-54 MMBtu/hr)	
CO	Good Combustion Practices	0.04-0.09	ULNB	0.055 (Vendor)
NO_x	ULNB	0.025-0.045	ULNB	0.035 (Vendor)
PM_{10}	Combust clean burning fuel	0.0075	Combust clean burning fuel	0.00051 (EPA)
$PM_{2.5}$	Combust clean burning fuel	0.0075	Combust clean burning fuel	0.00042 (EPA)
SO_2	RFG – sulfur removed	Subpart Ja	RFG – sulfur removed	Subpart Ja
VOC	Gaseous fuel combustion only	0.05	Gaseous fuel combustion only	0.03 (WebFire)
Small Boilers (70-120 MMBtu/hr)			Hydrogen Plant Heaters (134 MMBtu/hr, combined)	
CO	ULNB/GCP	0.06-0.12	Good Combustion Practices	0.055 (Vendor)
NO_x	ULNB	0.03-0.09	ULNB	0.051 (Vendor)
PM_{10}	Combust clean burning fuel	0.0075	Combust clean burning fuel	0.00051 (EPA)
$PM_{2.5}$	Combust clean burning fuel	0.0075	Combust clean burning fuel	0.00042 (EPA)
SO_2	RFG – sulfur removed	Subpart Ja	RFG – sulfur removed	Subpart Ja
VOC	Gaseous fuel combustion only	0.05	Gaseous fuel combustion only	0.03 (WebFire)

Table Notes:
RFG, refinery fuel gas
ULNB, Ultra Low NOx Burner
GCP, Good combustion Practices
Btu, British Thermal Units
CO, carbon monoxide
NO_X, oxides of nitrogen
PM, particulate matter
PM_{10}, particulate matter with an aerodynamic diameter of 10 microns or less
$PM_{2.5}$, particulate matter with an aerodynamic diameter of 2.5 microns or less
SO_2, sulfur dioxide
VOC, volatile organic compounds

1. NO_X BACT Analysis for the external combustion sources

The vacuum heater and crude heater as proposed will combust refinery fuel gas that has been treated to remove sulfur. The new hydrogen plant will use two reformer heaters with a combined rating of 134 MMBtu/hr to make hydrogen by reacting waste gas from the plant (PSA purge gas) and pipeline quality natural gas with steam. The PSA purge gas typically contains a small amount of unreacted natural gas, CO, and CO_2 from initial combustion. The PSA purge gas has negligible sulfur content.

2 Roy Huntley of EPA, Region 5, National Emission Inventory

NO_X emissions can be controlled by minimizing the formation of NO_X during the gas combustion process or by reducing NO_X after the combustion process. Calumet considered the following control options:

Combustion Control
Ultra Low NO_X Burners (ULNB)
Low NO_X burners (LNB)

Post-Combustion Control
Selective Catalytic Reduction (SCR)
Selective Non-Catalytic Reduction (SNCR)
Non-Selective Catalytic Reduction (NSCR)

LNBs are a practical approach to minimizing the formation of NO_X during combustion. LNBs are designed to control the mixing of fuel and air to keep the flame temperature low and dissipate heat quickly to lower thermal NO_X production. LNBs have traditionally been selected as BACT for natural gas fired heaters and boilers. LNBs are capable of NO_X reductions of 40–60 percent from uncontrolled levels. LNBs are technically feasible for the proposed heaters.

ULNBs use many of the same technology advancements currently in use for LNBs. There are a number of burner configurations that are referred to as Ultra Low NO_X. ULNBs generally use proprietary processes in which the staged mixing of air, fuel, and recirculated flue gas minimizes the formation of NO_X in the flame. For ULNBs, preheated flue gas is fed back to the heater. This flue gas lowers the temperature of combustion, minimizing NO_X formation. The addition of preheated flue gas ensures maximum heater efficiency. Ultra Low NO_X combustion technology is technically feasible for the proposed heaters.

SCR is a post-combustion control technology. NO_X emissions are reduced by mixing ammonia with the combusted flue gas and passing the mixture over a heterogeneous catalyst in the presence of oxygen (O_2). The process is selective, implying that the ammonia reagent preferentially reacts with NO_X rather than O_2 (although O_2 is a necessary reaction component). The process is catalytic meaning the reactions take place with enhanced reaction rates due to the presence of a catalyst. The overall reactions are the same for both SCR and SNCR technologies. The presence of the catalyst reduces the activation energy of the desired reactions, thereby reducing the applicable temperature between 500°F and 850°F for conventional SCR. The reducing agent employed by the majority of SCR systems is gas phase ammonia (NH_3). Though aqueous NH_3 solutions below 29 percent have a substantial vapor pressure at normal air temperatures, SCR systems generally require a vaporizer to provide sufficient NH_3 vapor to the system. The desired level of NO_X reduction increases with higher NH_3 to NO_X ratios but also results in increased levels of unreacted NH_3 being directly emitted to the air instead of being used in the chemical reaction (NH_3 slip). SCR is a technically feasible option for reducing NO_X emissions from the heaters.

SNCR refers to the process where NO_X emissions are reduced by NH_3 in the presence of O_2. This process does not use a catalyst for the reaction. The optimum reaction temperature is 1,100°F to 1,400°F. An injection grid will disperse the reducing agent uniformly throughout the exhaust flow. The reducing agent employed by the majority of SNCR systems is aqueous urea because it is safer. The desired level of NO_X reduction increases with higher NH_3 to NO_X ratios. This process also results in increased levels of unreacted NO_3. SNCR is technically feasible for the heaters.

NSCR is a post-combustion control technology. Emissions from fuel rich combustion are sent to a catalyst where NO_X emissions are reduced. The heaters will not operate with a fuel rich environment; therefore, NSCR is not technically feasible for the heaters.

Technical Feasibility of Possible NO_X Control Technologies
SCR, and SNCR were identified as technically feasible for controlling NO_X emissions from each of the proposed heaters, while ULNB was identified as technically feasible for controlling NO_X emissions from the #2 Crude Unit, MHC, and hydrogen plant heaters. Therefore, these four control technologies were further evaluated for energy, environmental, and economic impacts.

SCR and SNCR require adding ammonia, a difficult to manage and potentially hazardous gas stream to the heaters, and SCR and SNCR require ongoing operations and maintenance. The vendor of the hydrogen plant heaters provided a cost estimate for installing SCR on the hydrogen plant heaters to be approximately $750,000 (without an NH_3 tank, CEMS, or ongoing maintenance). Adding this control to meet the lowest BACT will reduce annual emissions from the hydrogen plant heaters by approximately 24 tons per year (TPY), and will cost at least $32,000 per ton of reduction, without considering costs for additional equipment and maintenance.

The vendor stated that costs for an SCR on the #2 Crude Unit or MHC heaters would be higher than adding it to the hydrogen heating unit because the draft-type is different. The cost for SCR on these units was estimated as 20 percent higher than the quoted hydrogen plant heater's SCR cost. Adding SCR to these units to meet the lowest BACT will reduce annual emissions from the crude heater by approximately 2 TPY, without considering costs for additional equipment or maintenance. The cost of SCR was estimated at approximately $460,000 per ton of NO_X reduction. Annual emissions from the vacuum tower and combination feed heaters would be reduced by approximately 2 TPY for each heater, at approximately $550,000 per ton of NO_X reduction for each heater. Annual emissions from the fractionation feed heater would be reduced by approximately 1 TPY, at approximately $800,000 per ton of reduction. These costs are excessive for a relatively small reduction in emissions. Therefore, ULNB technology was chosen as the proposed BACT for the #2 Crude Unit Heaters, the MHC heaters, and the Hydrogen Plant with the following emission limits (vendor guarantee).

Based on information provided by Calumet and guaranteed by the vendor, the Department determined that the following constitutes BACT. All external combustion devices shall be equipped with an ULNB and the Department determined that the BACT NO_X emission limits are all based on a 30-day rolling average, and are as follows:

Emission Unit	Design Capacity (MMBtu/hr)	Emission Control Technology	Proposed BACT NO_X Emission Limit (lb/MMBtu)	Total NO_X Emissions (in TPY)
Crude Heater (H-2101)	71	ULNB	0.035	10.88
Vacuum Heater (H-2102)	27	ULNB	0.035	4.14
Combined Feed Heater (H-4101)	54	ULNB	0.035	8.28
Fractionator Feed Heater (H-4102)	38	ULNB	0.035	5.83
Reformer Heaters (H-31A & B)	134	ULNB	0.051	29.94

Calumet must also meet the requirements of 40 CFR 60, Subpart Ja for each of these heaters. In accordance with this subpart, the natural draft process heaters (H-2101, H-2102, H-4101, H-4102) are subject to: 40 ppm_v NO_X (dry basis, corrected to 0 percent excess air) determined daily on a 30-day rolling average basis, or 0.04 lb NO_X/MMBtu-HHV basis, determined daily on a 30-day rolling average.

The Reformer Heaters (H-31A and H-31B) are forced draft process heaters and must comply with: 60 ppm_v NO_X (dry basis, corrected to 0 percent excess air) determined daily on a 30-day rolling average basis; or 0.06 lb NO_X/MMBtu-HHV basis determined daily on a 30-day rolling average.

2. VOC and CO BACT Analysis for the external combustion sources

VOC and CO emissions from fuel combustion are the result of incomplete combustion. Incomplete combustion is often caused by low temperatures in the combustion zone, poor air/fuel mixing, or lack of oxygen to complete combustion. CO is a product of the chemical reaction between carbonaceous fuels and oxygen. The EPA's RBLC and California Air Resources Board BACT Clearinghouses as well as other data sources show GCP, oxidation catalyst, and thermal oxidation as technically feasible for reducing CO emissions from refinery process heaters. Control technologies evaluated for the reduction of VOC and CO include the following:

- Oxidation catalyst;
- Thermal Oxidation; or
- Good combustion practices.

Oxidation catalysts are used post combustion to oxidize CO and VOCs into CO_2 and water. Oxidation catalysts are often used for natural gas fired engines and combustion turbines. Calumet noted that these types of systems are best suited with lower exhaust volumes when there is little variation in the type and concentration of VOC, and where catalyst poisons or other fouling contaminants such as silicon, sulfur, heavy hydrocarbons and particulates are not present. The exhaust from these heaters would have high volume, variable VOC concentrations and could potentially result in catalyst fouling due to contaminants such as sulfur and heavy hydrocarbons. Therefore, the potential problems associated with an add-on device and the potential to increase emissions by interfering with combustion makes an oxidation catalyst not technically feasible.

Good combustion practices start with the design of the fuel burning equipment and include the proper operation and maintenance of the combustion equipment. Designing the equipment using good combustion practices lowers CO and VOCs by ensuring complete combustion. Proper operation and maintenance ensures that the equipment is operated as designed. Good combustion practices are technically feasible for the heaters.

Thermal oxidation generally requires operating temperatures in the 1200 to 2000 ºF range to ensure conversion of CO to CO_2. CO removal efficiencies of 90% removal can be achieved with thermal oxidation. The combustion process occurs in two separate stages, including: the combustion of fuels, and the combustion of pollutants. The first stage of combustion is rapid and an irreversible chemical reaction. In the second stage, the heated gases from the burners pass through residence chambers where the CO is oxidized. Residence time, heating value of the gas stream, and operating temperatures determine the efficiency of the process. Raising the exit gas to the appropriate temperature range would require a significant amount of energy and generate increased combustion emissions. Heaters can be considered thermal oxidation themselves and adding another thermal oxidation downstream of a heater to control CO is impractical.

Calumet proposed good combustion practices such as adequate fuel residence times, proper fuel-air mixing, and temperature control. After review of EPA's RBLC and the above analysis, the Department determined good combustion practices constitutes BACT for CO and VOC.

Calumet proposed and the Department agreed that a CO limit of 0.055 lb/MMBtu based on a 30-day rolling average for the following heaters: H-2101, H-2102, H-4101, H-4102 is BACT. For the Hydrogen Plant Reformer Heaters (31A and 31B), Calumet proposed and the Department agreed with a CO BACT emission limit of 0.03 lb/MMBtu based on a 30-day rolling average.

3. $PM/PM_{10}/PM_{2.5}$ BACT Analysis for external combustion devices

PM emissions associated with fossil-fuel combustion primarily consist of solid particles ranging in size from 0.05 micron (µm) to 1 µm. The majority of particulates from fossil-fuel combustion will have an aerodynamic diameter of less than 2.5 µm ($PM_{2.5}$) and are generally classified as respirable PM. Natural gas (as well as RFG) combustion produces minimal ash and the potential for producing PM emissions is considerably lower than for coal, wood, or oil-fired combustion units.

Calumet evaluated the following pre and post combustion control technologies were evaluated for the proposed heaters.

- Wet Scrubbers;
- Clean Fuels;
- Good Combustion Practices;
- Baghouse; and
- Electrostatic Precipitation.

Wet scrubbers are add-on controls that use water entrainment to remove PM. The gas stream enters the scrubber and particulates are captured by water droplets that settle in the bottom of the scrubber. The water containing PM settles and the clarified water is reused. Although, wet scrubbers provide quenching for hot gas streams and can minimize explosion risk; this control technology generates a wet sludge that has to be managed. The uncontrolled PM emission levels are too low to justify adding an additional waste stream to the process. Given this, a wet scrubber is not technically feasible as a control technology for these relatively small external combustion sources.

Combustion of fossil-fuels with higher ash content has an increased potential to emit PM. Similarly, fuels containing a high percentage of nitrogen and sulfur can produce nitrates and sulfates when combusted that increase condensable PM. Using a clean fuel that contains negligible amounts of ash, nitrogen, and sulfur will minimize the generation of PM emissions. The proposed heaters will use pipeline quality natural gas and low sulfur fuel gases. These fuel gases are fuels that contain negligible amounts of ash and other PM. Additionally, the sulfur content of the fuel is low enough to meet FCAA requirements and to minimize the generation of condensable PM. The use of clean fuels as a control technology has been deemed technically feasible.

Elements in the fuel that are left uncombusted can also increase PM emissions. Using good combustion practices to increase combustion efficiency in the heater could decrease the amount of uncombusted elements thereby decreasing PM emissions. Therefore, the use of good combustion practices is a technically feasible control technology.

Baghouses are installed on external combustion sources with high volume gas streams and high particulate concentrations. Baghouses are not typically installed on process heaters that are fired on pipeline natural gas and process fuel gases. The flue gases will not be mixed with process-related dust emissions; therefore, the only particulates from these sources will be a product of natural and fuel gas combustion. Because baghouses are generally not used and due to the low air volume and minimal PM concentration of the flue gas associated with combustion of these fuels, the baghouse control technology is not technically feasible.

An ESP is a particle control device that uses electrical forces to move the particles out of the gas stream onto collector plates. ESPs are used to capture coarse particles at high concentrations. Similar to baghouses, ESPs are typically used for applications with large volume and high particulate concentrations. The ESP control technology is not technically feasible for the process heaters based on the very small particle size and the possibility of re-entrainment due to low resistivity.

None of the add on PM control devices have been found to be suitable for process heaters burning gaseous fuels due to extremely low concentration of small particulates expected in gas fired heaters.

Using clean fuels (pipeline quality natural gas or refinery fuel gas) and good combustion practices were the only control technologies identified as technically feasible and proposed as BACT. Calumet proposes and the Department concurs the following $PM/PM_{10}/PM_{2.5}$ emission limits for the expansion project process heaters (H-2101, H-2102, H-4101, H-4102, H-31A and H-31B):

PM/PM_{10} = 0.00051 lb /MMBtu based on a 30-day rolling average.
$PM_{2.5}$ = 0.00042 lb /MMBtu based on a 30-day rolling average.

4. SO_2 BACT Analysis for external combustion devices

SO_2 emissions from fuel combustion are related to the amount of sulfur present in the fuel gas. Refinery gas contains sulfur, mostly in the form of hydrogen sulfide (H_2S). When burned in a boiler or heater, essentially all the sulfur in the fuel is oxidized to SO_2.

The following is a list of control technologies for controlling SO_2 emissions:

- Fuel specification - low sulfur fuels,
- Wet flue gas desulfurization (wet FGD),
- Advanced flue gas desulfurization (AFGD), and
- Dry absorption (dry FGD).

As mentioned above, most all of the sulfur combusted in the fuel will be converted to SO_2. SO_2 emissions from fuel combustion are the result of oxidation of any sulfur compounds in the fuel. Choosing lower sulfur fuels results in lower SO_2 emissions. Calumet proposes to burn low sulfur fuel (natural gas or RFG) in the H-2101, H-2102, H-4101, H-4102 heaters. The hydrogen plant reformer heaters (31A and 31B) will combust natural gas and PSA purge gas, which both are inherently low in sulfur. The use of low sulfur fuel is technically feasible.

The simplest method for flue gas desulfurization is with the use of a wet scrubber. In a wet caustic scrubbing system, the flue gas and a caustic solution flow counter-current to each other. The sulfur reacts with the caustic solution and is stripped out of the flue gas. Approximately 90-99% reduction can be achieved. However, FGD is not applied to fuel gas combustion sources because emissions of SO_2 are minimal and it is not technologically feasible to scrub the small amount (less that 3 TPY) from flue gas combustion.

The AFGD process accomplishes SO_2 removal by utilizing a single absorber which performs three functions which are pre-quenching the flue gas, absorption of SO_2, and oxidation of the resulting calcium sulfite to wallboard-grade gypsum. Incoming flue gas is cooled and humidified with process water sprays before passing to the absorber. Approximately 95-99.5% reduction can be achieved. In the absorber, two tiers of fountain-like sprays distribute reagent slurry over polymer grid packing that provides a large surface area for gas/liquid contact. The gas then enters a large gas/liquid disengagement zone above the slurry reservoir in the bottom of the absorber and exits through a horizontal mist eliminator. As the flue gas contacts the slurry, the SO_2 is absorbed, neutralized, and partially oxidized to form calcium sulfite and calcium sulfate.

Dry FGD systems spray lime slurry into an absorption tower where the SO_2 is absorbed by the slurry forming calcium sulfite and calcium sulfate. The liquid-to-gas ratio is such that the water evaporates before the droplets reach the bottom of the tower. The dry solids are carried out with the gas and collected with a fabric filter or an ESP. Approximately 90-95% reduction can be achieved.

Neither recent permits nor the RBLC database required AFGD, wet FGD or dry FGD as BACT for any process heater. In addition, Calumet determined that any type of flue gas desulfurization is not feasible for these types of fuel gas combustion sources because emissions of SO_2 are minimal. Therefore, the only control strategy identified for the fuel gas-fired process heaters is adherence to fuel specifications - low sulfur fuel. This control strategy is technically feasible.

In addition to using low sulfur fuels, Calumet's corresponding fuel combustion devices associated with this project are subject to 40 CFR 60, Subpart Ja. As such, Calumet's heaters must meet the emission limits in either (i) or (ii), below:

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) and SO_2 in excess of 8 ppmv (dry basis corrected to to 0-percent excess air); 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.

Based on review of the above, the Department determined that Calumet must use low sulfur fuels meeting the applicable requirements of 40 CFR 60, Subpart Ja as BACT for SO_2. This BACT determination is similar to other recently permitted sources.

5. <u>GHG BACT Analysis for external combustion devices</u>

Calumet provided a BACT analysis in the initial application dated October 2, 2013. On December 23, 2013, Calumet provided additional information regarding the Green House Gas (GHG) BACT analysis (included as Appendix C and Appendix J in the permit application). All of this information, as presented by Calumet, is summarized below.

a) External Combustion Devices

GHGs are generally defined as an aggregate of six pollutants, including: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFC), perfluorocarbons (PFC) and sulfur hexafluoride (SF_6). Each of these pollutants has a subsequent global warming potential (GWP) that is then used to calculate the CO_2 equivalent (CO_2e). The sum of the applicable pollutants determines whether the permit is major for GHGs, or not.

Refineries are considered a "listed source" category and a modification would be considered major for GHGs with a CO_2e increase of 75,000 TPY, or greater. Calumet estimates the expansion project's CO_2e at 243,797 TPY which would be major for GHG.

It has been well documented that CO_2 is the predominant GHG emitted by petroleum refineries, accounting for almost 98% of all GHG emissions. Given this, the GHG BACT analysis primarily focuses on CO_2 emissions because the other constituents such as CH_4 and N_2O are relatively minimal in comparison. Generally speaking, as with all refineries, the carbon input is primarily in the form of crude oil feedstock. However, most of the carbon that enters into the facility as feedstock, exits in the form of liquid fuel products, such as gasoline and diesel fuel. A small percentage of carbon input will exit as CO_2 emissions as a result of combustion and chemical processes used to produce heat, steam, and the hydrogen required by Calumet.

Calumet evaluated several GHG control technologies. The basis for selection or justification of not selecting each control technology was derived from the October 2010 EPA Office of Air and Radiation document titled "Available Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry," which was included as Appendix J (of the permit application), and a recent Federal PSD air permit issued by EPA Region 8 included in Appendix K (of the permit application).

The primary GHG emissions sources associated with this proposed expansion project are the process heaters that will be installed in the new crude unit, the new MHC unit, and the new hydrogen plant. There will be two new refinery fuel gas or natural gas-fired heaters per unit. As mentioned above, the proposed project also includes changes to the existing HTUs, the addition of a new secondary flare, and a new railcar loading/unloading rack. However, the emissions from these particular units are minimal in comparison to the process heaters listed below.

#2 Crude Unit
Crude Heater (H-2101) - 71 MMBtu/hr
Vacuum Heater (H-2102) - 27 MMBtu/hr

Mild Hydrocracker (MHC)
Combined Feed Heater (H-4101) -54 MMBtu/hr
Fractionator Feed Heater (H-4102) - 38 MMBtu/hr

The #2 Crude Unit heaters and the MHC heaters will combust mostly refinery fuel gas (RFG) that has been treated to remove sulfur, or natural gas. There are no post combustion control devices on these combustion sources.

Hydrogen Plant #3 (natural gas combustion and PSA off gas)
Hydrogen plant consists of two reformer heaters (H-31A and H-31B) with a total combined capacity of 134 MMBtu/hr.

The new hydrogen plant consists of two reformer heaters that are used to make hydrogen by reacting PSA tail gas from the hydrogen plant, and pipeline quality natural gas with steam. The PSA tail gas typically contains a small amount of unreacted natural gas, CO, and CO_2 from initial combustion. The PSA purge gas has negligible sulfur content. There are no post combustion control devices on these heaters. Hydrogen plants and hydrogen production typically contribute between 5 and 30% of GHG emissions in a refinery depending upon the configuration. Hydrogen demand for refinery operations has been steadily increasing in order to meet more stringent quality standards.

Subpart C Tier 3 methodology from the Greenhouse Gas Mandatory Reporting Rule and the 2012 refinery fuel gas compositional data was used to estimate the primary GHG emissions of CO_2, CH_4, and N_2O emissions for each of the external combustion sources. This analysis only covers emissions occurring from emissions at the Calumet refinery. Emissions that occur off-site due to combustion of transportation fuels are not subject to BACT.

The generation of GHGs is directly related to fossil-fuel characteristics, combustion practices, and the combustion efficiency of the unit. This analysis will include pre- and post-combustion control technologies for the control of GHGs.

- Carbon capture and storage (CCS) using solvent separation;
- CCS using physical adsorption;
- CCS using cryogenic separation;
- CCS using membrane separation;
- Pre-combustion CCS using oxyfuel process;
- Energy efficient design;
- Good combustion practices; and
- Low carbon fuel.

All fossil fuels contain significant amounts of carbon, and during the combustion of fossil fuels, fuel carbon is oxidized into CO and CO_2. When CO is emitted it gradually oxidizes to CO_2 in the atmosphere. Full oxidation of fuel carbon to CO_2 is desirable to minimize CO (a long standing criteria pollutant).

Carbon capture and storage (CCS) using solvent separation
Unlike fossil fuel combustion at electric power plants that emit CO_2 from one stack or a small number of stacks in close proximity, petroleum refineries CO_2 emissions are generated and emitted from sources and stacks scattered throughout the facility which limits carbon capture.

There are several solvents being researched for CO_2 capture, but monoethanolamine (MEA) is the solvent that is the most commercially available. MEA can react with CO_2 quickly at low partial pressures, but with the following limitations: (1) can cause corrosion in the presence of oxygen and other impurities; (2) results in high solvent degradation due to reactions with NO_X and SO_2; (3) requires high energy use for solvent regeneration. Solvent separation as a method for capturing CO_2 was deemed technically feasible, but additional equipment costs and the ongoing costs of compressing, transporting, and storing the captured CO_2 made this option cost prohibitive.

As such, CCS using solvent separation has been eliminated as BACT for this expansion project due to the overall economic, energy, and environmental impact of implementing this GHG control technology. Further, according to EPA Region-8 statement of basis for the Sinclair Wyoming Refining NSR-PSD permit: "EPA believes post-CCS is financially prohibitive…due to its overall cost as a GHG control strategy." Calumet provided a copy of this statement of basis in the permit application to remove this as an option to control GHG. Additionally, this option has not been demonstrated successfully at refineries and the effectiveness of these carbon capture technologies would also be limited by the lack of gas turbines and process heater exhaust CO_2 concentrations.

CCS using physical adsorption, cryogenic separation, or membrane separation
CCS using physical adsorption, cryogenic separation, or membrane separation are technically infeasible because (as mentioned above) these carbon capture technologies have not be demonstrated effective on a large scale petroleum refinery process heater project.

Pre-combustion CCS using oxyfuel process
The pre-combustion carbon capture and storage control technology involves replacing combustion air with pure oxygen, resulting in a concentrated CO_2 exhaust stream due to the lack

of nitrogen being present. The use of pure oxygen also improves combustion efficiency so that more of the fuel carbon is converted to CO_2. This technology would still require additional separation equipment prior to combustion to isolate purge oxygen from the normal air concentration of approximately 79 percent nitrogen and 21 percent oxygen. Equipment for drying, compressing, transporting, and storing the captured CO_2 would also be required. As mentioned above, additional equipment costs and the ongoing costs of compressing, transporting, and storing the captured CO_2 made this option cost prohibitive. Additionally, this control technology has not been demonstrated on refinery process heaters, making it technically infeasible for implementation at this time.

Energy efficient design, Good combustion practices, and Low carbon fuels

As part of the complete combustion cycle, fuel carbon molecules are converted to CO_2. Methane, a one carbon fuel, would yield one CO_2 molecule for every molecule of CH_4 combusted. Similarly, a four carbon fuel such as butane would yield four CO_2 molecules for every molecule of butane combusted. According to the GHG Mandatory Reporting Rule (40 CFR Part 98, Subpart C), refinery fuel gas is considered a low carbon fuel at 59 kilograms per million British thermal unit (kg/MMBtu).

The table below presents the amount of CO_2 formed when combusting fossil fuels. As the table below shows, gaseous fossil fuels contain the least amount of carbon in comparison to other fuels.

CO_2 Emission Factors*	
Fuel	**Lbs CO_2 per MMBtu**
Petroleum coke	206
Coal (sub-bituminous)	213
Residual Oil	174
Refinery Fuel Gas**	141
Natural Gas	118
*Reference: US Energy Information Administration, http://www.eia.gov/oiaf/1605/coefficients.html	

The heaters at Calumet will combust refinery fuel gas which is already inherently a lower carbon fuel. Other fuels that have been identified with lower carbon formation rates are syngas, PSA tail gas, and natural gas. However, the production of additional syngas or PSA tail gas would lead to overall increases in GHG emissions from the refinery and therefore, do not represent a feasible option for reducing GHG emission. Natural gas is commercially available and would yield slightly reduced carbon emission rates, but using natural gas would displace refinery fuel gas and would necessitate disposal of this fuel gas by combustion elsewhere at the refinery (e.g. flares) and would potentially increase total refinery emissions.

The use of low carbon fuels and good combustion practices are inherent to the refinery's operation for process heaters at Calumet. Most refineries include these practices in order to provide the required heat/energy demand needed in the refining process while maximizing fuel efficiency and minimizing operating costs. Specifically, the use of process heat to generate steam, process integration and heat recovery in the process heaters, and excess combustion air monitoring and control are utilized throughout the refinery. As such, Calumet believes no alternate control options involving the use of lower-carbon fuels in process heaters would be technically feasible for reducing GHG emissions over the proposed use of refinery fuel gas.

Using good combustion practices to increase combustion efficiency will decrease the amount of uncombusted fuel elements; thereby, decreasing criteria pollutant emissions while increasing CO_2 emissions. This actually helps to decrease the overall CO_2e emissions by converting fuel components with a higher carbon content and higher GWP to CO_2 which has a GWP of one. Good combustion practices include good air/fuel mixing in the combustion zone, sufficient residence time to complete combustion, proper fuel gas supply system design to minimize fuel gas quality fluctuations, good burner operation, and maintenance, high temperatures in the primary combustion zone, and excess oxygen levels high enough to complete combustion. This control technology is technically feasible because it has been demonstrated effective for refinery process heaters.

Combustion Air Preheat

The flue gas from the Crude Heater and Vacuum Heaters will be used to generate steam. Using the flue gas to generate steam reduces the flue gas temperature such that it is not suitable to then be further used to preheat combustion air. Recovering the heat from the flue gas to generate steam reduces GHG emissions by the same amount as if the heat was recovered to preheat combustion air. Therefore, there would be no realized benefit. Calumet determined that combustion air preheat is not technically feasible for the Crude Heater and Vacuum Heater when waste heat is used to generate steam.

The flue gas must be of sufficient temperature to preheat combustion air to minimize corrosion due to condensation. Following steam production, the flue gas temperatures for the MHC Combined Feed Heater and the Fractionator Feed Heater are not high enough to preheat combustion air, making this energy efficient practice technically infeasible for these units.

However, the flue gas from the Hydrogen Plant Heaters will have adequate heat for preheating combustion air. Preheating the combustion air would help to reduce the amount of combustion fuel required to achieve the desired process temperature. Combustion air preheat is technically feasible and will be implemented as part of the energy efficient design for the Hydrogen Plant Heater.

Heat Recovery

Heat recovery helps to reduce GHG emissions by reducing the amount of combustion fuel it takes to generate the required amount of steam for the process and to heat products to the appropriate temperature. The flue gas from the Crude Heater and Vacuum Heater will be used to generate steam. Additional heat recovery from the flue gas is not technically feasible.

Heat recovery boilers can be utilized on the MHC Combined Feed Heater, the Fractionator Feed Heater, and the Hydrogen Plant Heater. Heat recovery as part of an energy efficient design is technically feasible for the MHC unit and Hydrogen Plant. Heat recovery will be implemented on the MHC Combined Feed Heater, Fractionator Feed Heater, and the Hydrogen Plant Heater.

Excess Combustion Air Monitoring/Control

Monitoring and controlling the amount of excess combustion air reduces GHG emissions by making sure the higher carbon components undergo complete combustion, converting the carbon molecules with higher GWP to CO_2 with a GWP of one. Monitoring and controlling the amount of excess combustion air is technically feasible for each of the five heaters included in this application. Excess air monitoring and control is being implemented as part of energy efficient design for each of the process heaters included with this expansion project.

As such, Calumet selected energy efficient design and good combustion practices (ensure complete combustion and minimize energy use) in addition to the use of low carbon fuels (refinery fuel gas and natural gas) as BACT for each of the process heaters associated with the expansion.

The proposed BACT emission rates for the #2 Crude Unit (crude heater and vacuum heater) and the new MHC Unit (combined feed heater and fractionator heater) are 141 lbs of CO_2e/MMBtu and 142 lbs CO_2e/MMBtu, respectively. It was noted by Calumet that these emission limits were chosen using 40 CFR Part 98, Subpart C as guidance, and the consideration of varying refinery fuel gas properties.

The proposed BACT emission rates for the #3 Hydrogen Plant (two, 67 MMBtu/hr reformer heaters) is 133,038 tons of CO_2e per year based on a 12-month rolling average. These mass-based emission limits are being proposed in lieu of mass per heat content limits because the Hydrogen Plant Heater combusts a gas mixture that is 90 percent PSA tail gas and 10 percent pipeline natural gas. Fluctuations in the fuel volume percentages could make it difficult to demonstrate compliance with a mass per heat content limit.

B. HTU and Kerosene HTU

The HTU Heater and Kerosene HTU at Calumet will change feedstock service as part of the proposed project. The change in service for the two HTU's will not affect the existing PTE for these units. The maximum rated heat capacity of the HTU and the combustion fuel will remain the same. According to Calumet, there are no modifications within the HTUs required. Therefore, the changes to feedstock are not subject to BACT.

C. Flares

Calumet proposed a cascade flare system which would be a series of two flares connected to one flare gas header system arranged with increasing pressure set points so that discharges would be initially directed to the first flare (primary flare). If the discharge pressure exceeds a set point at which the flow to the primary flare's capacity, then the flow would be diverted to the second flare. By definition, a secondary flare is a flare in a cascaded flare system that provides additional flare gas capacity and pressure relief to a flare gas system when the flare gas flow exceeds the capacity of the primary flare. A secondary flare is generally characterized by infrequent use and the system is required to must maintain a water seal.

Calumet's existing flare will be modified to increase design capacity for emergency shutdown flow and to reduce the sulfur concentration of the process gas being flared. Process gases that cannot be collected and routed to the fuel gas system are vented to a near-atmospheric pressure relief gas header and flared. The relief gas header serves primarily as a safety device that collects flammable process gases and routes them to the flare for destruction in lieu of atmospheric venting. Relief gas headers have connections for anticipated releases such as equipment depressurization and purging related to planned maintenance activities, turnaround, equipment startup, and shutdown. Relief gas headers also have connections for unplanned releases such as PRVs and safety control valves that vent during upsets, malfunctions, and emergency situations.

Calumet is proposing to install a second safety flare that will only be used when the relief header flow in exceeds the design flow for the existing flare. Calumet proposes to install a water seal in the relief gas header upstream of the existing flare. During periods of excess flow (e.g., process upsets, malfunctions, shutdowns, etc.), the relief gas header pressure will increase above the water seal pressure and the gas will be temporarily routed to the safety flare until the relief gas header pressure decreases. The new flare will only be used to safely vent gases from equipment during process upsets, emergencies, and shutdowns where the emissions could result in potential health or environmental hazards if the emission were discharge directly to the atmosphere.

Calumet also proposes to install a caustic scrubber upstream of the existing flare to remove sulfur from the flare gas prior to being burned. The overall goal is to reduce the sulfur concentration of the flare gas for compliance with the New Source Performance Standards (NSPS), 40 CFR 60, Subpart Ja. An additional sulfur scrubber is not required downstream of the water seal prior to the safety flare because Subpart Ja does not apply during periods of shutdown and malfunction and the scrubber could increase line pressure downstream of the water seal causing excess flow to backup into the existing flare line and exceed its design capacity.

Calumet determined that although technically feasible, the installation of a fuel gas recovery system (FGRS) used to recover flare gas and reduce emissions would be cost prohibitive at an approximate capital cost of $4,000,000. This was eliminated from further consideration as it is not economic.

Calumet reported that the RBLC database showed several flares with emission limits on criteria pollutants (including PM, NO_X, SO_2, CO, and VOC). However, most of the emission limits were associated with refinery flares in New Mexico, Louisiana, and Texas. The emission limits for the New Mexico facility only apply to the pilot and purge gas combusted in the flare and not for the emergency vent gas flow. The database indicates there may be specific state flare regulations in Louisiana and Texas for CO and SO_2 emissions, but overall most flares in the RBLC database reference compliance with Subpart J and/or Subpart Ja, good combustion practices, and proper design (e.g., steam or air assist system for PM control) as BACT for criteria pollutants.

Pursuant to 40 CFR 60, Subpart Ja, modification to an existing flare would be triggered for any activities in §60.100 paragraphs (c)(1) or (2). The Department determined that the changes being proposed to the existing flare (and the new flare system) would qualify as a modification and therefore, Calumet's flare system must meet the requirements of 40 CFR 60, Subpart Ja. Calumet's flare system is proposed to be used as a safety flare and only in the event of an emergency. An emergency flare as defined in Subpart Ja would be a flare that combusts gas exclusively released as a result of malfunctions (and not startup, shutdown, routine operations or any other cause) on four or fewer occasions in a rolling 365-day period. With this definition, Calumet's flares would be considered non-emergency flare which is defined as any flare that is not an emergency flare.

In accordance with 40 CFR 60, Subpart Ja modified flares must:

- Comply with the162 ppmv short-term H_2S limit (comply by November 13, 2015 or upon startup of the modified flare, whichever is later)
- Complete a Root Cause Analyses (RCAs) anytime:
    - the SO_2 emissions exceed 500 lbs in any 24-hour period
    - the discharge to the flare is in excess of 500,000 SCFD (above baseline flow)
- Develop and implement (with Department approval) a Flare Management Plan (FMP): by November 11, 2015 or upon startup of the modified flare, whichever is later
- Comply with Flare Monitoring requirements by November 11, 2015

As a result, Calumet proposed and the Department agrees that BACT for the modified flare system would be: utilization of good combustion practices, steam-assist design, and compliance with the provisions of 40 CFR 60, Subpart Ja. Additionally, Calumet proposes to continue to use low sulfur and low particulate pipeline quality natural gas as purge and pilot fuel to reduce PM and SO_2 emissions.

The Department determined that the installation of caustic scrubber and compliance with 40 CFR 60, Subpart Ja constitutes BACT. As such, Calumet shall not burn in any affected flare any fuel gas that contains H_2S in excess of 162 ppm_v determined hourly on a 3-hour rolling average basis.

All flare gas will be routed to the primary flare (existing flare) except during startup, shutdown and malfunction events when the secondary flare will be used to control emissions. Because the flare is permitted to be used approximately 9-hours per year, no further analysis is required.

D. Storage Tanks

MAQP #2161-27 was issued by the Department to modify the existing tank farm and to accommodate the current permit action for the proposed low sulfur fuel expansion project. This involved the removal of existing tanks, installation of new storage tanks and changes to the contents of some tanks. The previous tank modification application resulted in a net VOC emission decrease of 5.82 TPY.

With this permit application, Calumet also identified tanks that will be switching service in addition to five new storage tanks (Tanks 54, 145B, 201, 202, 203). Calumet reported that by using external floating roof design for the gasoline and crude oil tanks in addition to adding guide pole sleeves, these tanks would emit less VOC emissions (approximately -3.28 TPY). The table below describes the changes taking place with the proposed permit action.

Tank ID	Capacity	Current Service	New Service	Roof Type
Change of Service While In Place				
Tank 8	3,000 bbl	Naphtha	Caustic	IFR converted to Cone/Fixed
Tank 9	3,000 bbl	Asphalt	Caustic	Cone/Fixed
Tank 57	10,000 bbl	Regular Gasoline	Naphtha	IFR
Tank 58	10,000 bbl	Jet A/Kero	Kerosene	Cone/Fixed
Tank 100	1,100 bbl	Kerosene	#5 Fuel Oil	Cone/Fixed
Tank 101	1,100 bbl	Kerosene	#5 Fuel Oil	Cone/Fixed
Tank 115	5,200 bbl	#5 Fuel Oil	NAHS	Cone/Fixed
Tank 124	21,500 bbl	Crude	Naphtha	EFR
Tank 125	38,500 bbl	Crude	Diesel/GO	EFR
Tank 126	30,000 bbl	Regular Gasoline	Gasoline	EFR
Tank 127	21,500 bbl	Naphtha Charge	Gasoline	EFR
Tank 160	7,100 bbl	NAHS	Asphalt	Cone/Fixed
Reconstructed				
Tank 122	11,300 bbl	Gasoline	Wastewater Surge	EFR
New Construction				
Tank 54	5,000 bbl	--	Kerosene	Cone/Fixed
Tank 201	70,000 bbl	--	Crude Oil	EFR
Tank 202	70,000 bbl	--	Crude Oil	EFR
Tank 203	70,000 bbl	--	Crude Oil	EFR

As described above, many of the existing storage tanks will experience a change in service but will not be physically modified to accommodate this expansion.

Calumet identified the following in the BACT analysis:

- Thermal oxidizer;
- Flare;
- Catalytic oxidation; and
- Carbon Adsorption.

According to EPA's Air Pollution Control Fact Sheet, a thermal oxidizer can reduce VOC emissions by 95 to 98 percent, however there would likely be an increase in emissions of other criteria pollutants (e.g., CO, NO_X, etc.) Thermal oxidation is not optimal when the waste stream flow is variable, and is not cost effective when VOC concentration in the waste gas is low. Calumet determined that thermal oxidation would not be technically feasible for controlling storage tank emissions because the variability in the waste stream flow.

Flares could be used to reduce VOC emissions from storage tanks by up to 98 percent. However, like thermal oxidation, flares would reduce VOC emissions while resulting in an increase in emissions of other criteria pollutants. In addition, flares are generally used to control large volumes of waste gas associated with emergencies and malfunctions, but are more effective at a wide range of waste gas flow rates. Connecting the storage tank vent gas to the existing flare, or installation of a new flare, would require installation of piping, monitoring devices, and potentially sulfur treatment equipment to meet 40 CFR 60, Subpart Ja. Calumet's emission inventory provided with the application showed that the actual emissions from the existing storage tanks were 11.3 TPY. The small reduction in VOC emissions would be negated by the increase in emissions for other criteria pollutants. Therefore, flaring the storage tank vent gas was not selected as BACT due to the environmental impact.

The Air Pollution Control Fact Sheet for catalytic oxidation references 95 to 98 percent VOC emissions reduction efficiencies. Catalytic oxidation is not technically feasible because the waste gas stream from the storage tanks have low volume, variable VOC concentrations, and could contain fouling contaminants such as sulfur or heavy hydrocarbons. Therefore, catalytic oxidation is not technically feasible and has been removed from further consideration.

According the EPA Technical Bulletin for selecting adsorption media, carbon adsorption can be used to reduce VOC emissions in cases where concentrations are low and the air flow is high (above 5,000 actual cubic feet per minute (acfm)). The vent gas from the storage tanks will have a low VOC concentration, but will not have a high enough flow for carbon adsorption. As such, carbon adsorption would not be technically feasible because the low flow rate of the storage tank vent gas.

Calumet proposes to use a "safe sleeve" on all external floating roof storage tanks and the new storage tanks (Tanks 54, 145B, 201, 202 and 203). This design reduces roof fitting losses from the guide pole gasket area. Calumet estimated that by using guide pole sleeves on the EFR tanks, the potential minus the actual emissions would result in a net emission VOC decrease of 3.28 TPY.

The proposed BACT for the storage tank change of service associated with this application is installation of guide pole sleeves on all external floating roof tanks and meeting the applicable regulatory requirements (see table below for more information).

Storage tanks currently subject to 40 CFR 60, Subpart Kb will continue to be subject (if the new contents meet the vapor pressure thresholds). Gasoline storage tanks (light oil) will be subject to the requirements set forth in 40 CFR 63, Subpart CC. Kerosene, Jet A, and asphalt tanks (heavy oil) do not require controls due to the low vapor pressure of the liquids being stored in them (heavy oils less than 5.2 kilopascals (kPa)) and require no further analysis. However, the asphalt storage tanks will be subject NSPS Subpart UU that regulates opacity emissions. The table below lists the applicable regulatory requirements.

Tank ID	Service	Volume (bbls)	Roof Type	Controls	Regulatory Requirements
Tank 8	Caustic	3000	Cone/fixed	NA	NA
Tank 9	Caustic	3000	Cone/fixed	NA	NA
Tank 54	Kerosene	5000	Cone/fixed	NA	NSPS Kb
Tank 57	Naptha	10000	IFR	Primary & Secondary roof seals	NSPS Kb MACT CC
Tank 58	Kerosene	10000	Cone/fixed	NA	NA
Tank 100	#5 Fuel Oil	1100	Cone/Fixed	NA	NA
Tank 101	#5 Fuel Oil	1100	Cone/Fixed	NA	NA
Tank 115	NAHS	5200	Cone/Fixed	NA	NA
Tank 124	Naptha	21500	EFR	Primary & Secondary Roof Seals/Guidepole sleeves	NSPS Kb MACT CC
Tank 125	Diesel/Gasoil	38500	EFR	Primary & Secondary Roof Seals/Guidepole sleeves	NSPS Kb
Tank 126	Gasoline	30000	EFR	Primary & Secondary Roof Seals/Guidepole sleeves	NSPS Kb MACT CC
Tank 127	Gasoline	21500	EFR	Primary & Secondary Roof Seals/Guidepole sleeves	NSPS Kb MACT CC
Tank 145B	Wastewater	1300	EFR	Primary & Secondary Roof Seals/Guidepole sleeves	NSPS Kb & QQQ
Tank 160	Asphalt	7100	Cone/Fixed	NA	NSPS UU
Tank 201	Crude Oil	70000	EFR	Primary & Secondary Roof Seals/Guidepole sleeves	NSPS Kb
Tank 202	Crude Oil	70000	EFR	Primary & Secondary Roof Seals/Guidepole sleeves	NSPS Kb
Tank 203	Crude Oil	70000	EFR	Primary & Secondary Roof Seals/Guidepole sleeves	NSPS Kb

Note: storage tanks 100, 101, 115 and 58 were constructed prior to any regulatory requirements (pre- 40 CFR 60, Subpart Kb).

E. Equipment Fugitives

The proposed modification will cause an increase in VOC emissions for the facility as a result of additional piping components and wastewater drains. The VOC emissions increase associated with the leaking components and wastewater drains were provided in the initial application and estimated using the component counts, emission factors, and the control efficiency. Emission factors for fugitive components were taken from Table 2-2 in the "EPA Protocol for Equipment Leak Emission Estimates" (from November 1995). The control effectiveness for gas and light liquid fugitive components is based on the number of components screened that show greater than 50 ppm VOC. Heavy liquid fugitive control effectiveness is based on the frequency of regular audio-visual-olfactory inspections. Pressure relief valves prevent fugitive emissions, and are therefore estimated to control fugitive emissions by 95 percent.

Controlling VOC emissions from piping components and wastewater drains is very difficult due to the variation in flow and concentration, the number of individual sources to be controlled, and the physical distance separating each component. Installation of piping to collect equipment fugitives and route the VOC emissions to a single location for treatment via flare, thermal oxidation, catalytic oxidation or carbon adsorption is not technically feasible. Variations in flow and VOC concentration would also limit the effectiveness of the various control technologies. None of the equipment fugitive sources reviewed on the RBLC database utilize a pollution control device for treatment of VOCs from equipment leaks and wastewater drains. Sources typically use leak detection and repair (LDAR) strategies to reduce VOC emissions from equipment leaks.

Calumet proposed BACT for equipment leaks from new components is compliance with LDAR provisions of 40 CFR 60, Subpart VV as required by 40 CFR 63, Subpart CC for components in HAP service and 40 CFR 60, Subpart GGG for components in VOC service. Calumet also proposed BACT for emissions from new wastewater drains is compliance with 40 CFR 60, Subpart QQQ. The Department concurs with the proposed BACT.

IV. Emission Inventory

The following emission inventory reflects the action taking place for MAQP #2161-28. The emission inventories from previous permit actions are on file with the Department.

Table I
Expansion Project – Potential to Emit (PTE)

Proposed Expansion Source	Emissions (tpy)						
	NO_X	CO	VOC	SO_2	PM_{10}	$PM_{2.5}$	CO_{2e}
New Emitting Units							
Crude Heater	10.88	17.10	0.80	2.89	0.16	0.13	34,826
Vacuum Heater	4.14	6.50	0.30	1.10	0.06	0.05	13,244
Combined Feed Heater	8.28	13.01	0.61	2.20	0.12	0.10	26,487
Fractionation Feed Heater	5.83	9.15	0.43	1.55	0.08	0.07	18,639
#3 Hydrogen Plant Reformer A	14.97	8.80	0.002	0.05	0.08	0.12	65,540
#3 Hydrogen Plant Reformer B	14.97	8.80	0.002	0.05	0.08	0.12	65,540
Emergency Flare	0.81	2.91	1.01	9.77	0.02	0.02	368
Railcar Loading	0.23	0.69	1.21	0.00	0.00	0.00	0
Tanks	0.00	0.00	8.02	0.00	0.00	0.00	25
Fugitive Sources	0.00	0.00	74.80	0.00	0.00	0.00	0
Wastewater Fugitive Sources	0.00	0.00	7.03	0.00	0.00	0.00	0
Tank Farm Revamp Project[1]	5.64	1.38	7.30	0.40	0.34	0.34	4730
Existing Emitting Units undergoing an operational change							
Kerosene Heater (PTE)	4.11	1.61	0.08	0.79	0.01	0.01	3,599
DSL/GO HDS Heater (PTE)	6.21	3.46	0.25	2.39	0.05	0.04	10,799
Potential Emissions Increase	**76.06**	**73.43**	**101.84**	**21.20**	**1.02**	**1.01**	**243,797**

Table II
Actual Emissions (in TPY)

Actual Emissions from Existing Emitting Units (2011-2012 Average Emissions)							
Kerosene Heater	3.71	0.93	0.07	0.20	0.05	0.05	3,235
DSL/GO HDS Heater	3.97	0.55	0.11	0.29	0.07	0.07	4,847
Railcar Loading	0.05	0.15	0.16	0.00	0.00	0.00	0
Existing Tanks (per this application)	0.00	0.00	11.30	0.00	0.00	0.00	0
Existing Tanks (Tank Farm Revamp)[1]	0.50	0.13	13.01	0.02	0.03	0.03	425
2011-2012 Average Emissions	**8.24**	**1.76**	**24.65**	**0.51**	**0.15**	**0.15**	**8,507**
Potential minus Actual Emissions	**67.82**	**71.67**	**77.19**	**20.69**	**0.87**	**0.86**	**235,290**
Significant Emission Rate	**40**	**100**	**40**	**40**	**15**	**10**	**75,000**
PSD Required?	**Yes**	**No**	**Yes**	**No**	**No**	**No**	**Yes**

[1] Tank Farm Revamp Project was issued an air quality permit on October 23, 2013. Since the project is not completed, emissions are required to be included in the Expansion Permit emissions analysis.

Note: Actual emissions as of a particular date shall equal the average rate, in tons per year, at which the unit actually emitted the pollutant during a two-year period which precedes the particular date and which is representative of normal operations. Calumet used 2011 and 2012 as a basis for their actual emissions. In 2013, Calumet experienced a 6-week turnaround whereby the entire refinery was shutdown to perform maintenance activities.

As noted in Table I, Calumet's project would be considered a major modification subject to PSD for the following pollutants: NO_X, VOCs and GHG. However, after taking into account contemporaneous increases and decreases and an avoidance limit for NO_X, Calumet is only subject to PSD review for GHG and VOCs. See the permit conditions and the contemporaneous emission table below for more information.

Table III
Contemporaneous Emissions (Permitted increases or decreases)[3]

Source Permitted	Modification Type	Permit Iss. Date	Start up Date	Emissions NOx TPY	CO TPY	VOC TPY	SO_2 TPY	PM_{10} TPY	$PM_{2.5}$ TPY	CO_{2e} TPY
Tank 8 to naphtha service	Demin/MAQP 2161-21	8/5/2008	Jan-09			0.19				
Tank Heaters in 130, 132, 133	Demin/MAQP 2161-23	10/5/2009					0.27			
HDS Heater to RFG	Demin/MAQP 2161-23	10/5/2009					1.77			
Ethanol Tank permit	Demin/	10/15/2010				0.2				
MSAT Heaters	MAQP 2161-24	12/15/2010	9/12/2012	1.77	2.83	3.57	1.65	0.36	0.36	
S/D Old H-0402	MAQP 2161-24	12/15/2010	SD 9/1/13	-1.51	-0.38	-0.03	-0.07	-0.09	-0.09	
Boiler #3	MAQP 2161-25	2/9/2012	7/6/2013	5.03	9.01	1.43	7.66	2.65	1.98	61,800
Tank 29/51 relocate	Deminimus	6/6/2013	10/15/2013			1.24				
Tank Farm Revamp	MAQP 2161-27	10/23/2013	11/1/2013	5.14	1.25	-5.71	0.38	0.31	0.31	4,305
Total Change from Permit Actions Over Past 5 yrs.				**5.30**	**11.46**	**6.60**	**11.28**	**2.92**	**2.25**	**61800**
Expansion	under submittal	current	current	67.82	71.67	77.19	20.69	0.87	0.86	235290
Limit Boiler #1 and #2 Operation	under submittal	current	current	34.12	1.13	0.14	1.10	0.09	0.09	5604
Total Change from Current Application				**33.70**	**72.81**	**77.33**	**21.79**	**0.96**	**0.95**	**240,894**

Notes: (1) Calumet requested a federally enforceable limit on the operation of Boiler #1 and #2 which would limit emissions to those listed in the table above (e.g. 34.12 TPY of NOx)
(2)Total HAPs from the expansion project (emission inventory on file with the Department) is equivalent to 3.01 TPY.
(3) An increase or decrease in actual emissions is contemporaneous with the increase from the particular change only if it occurs between the date five years before construction on the particular change commenced, and the date that the increase from the particular change occurs.

Expansion Project Emission Calculations (in more detail):

Crude Heater					
Size	71	MMBtu/hr			
Operating hours:	8760	hrs/year			
Potential Fuel Use	1090 Btu/scf * 571 MMscf/yr =			622390	MMBtu/yr
PM Emissions					
Emission Factor:	0.00051	lb/MMBtu	(Roy Huntley/Ron Meyers of Region 5, EPA)		
Calculations:	0.00051 lb/MMBtu * 71 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			0.16	tons/yr
PM10 Emissions					
Emission Factor:	0.00051	lb/MMBtu	(Roy Huntley/Ron Meyers of Region 5, EPA)		
Calculations:	0.00051 lb/MMBtu * 71 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			0.16	tons/yr
PM2.5 Emissions					
Emission Factor:	0.00042	lb/MMBtu	(Roy Huntley/Ron Meyers of Region 5, EPA)		
Calculations:	0.00042 lb/MMBtu * 71 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			0.13	tons/yr
CO Emissions					
Emission Factor:	0.055	lb/MMBtu	(BACT and Vendor Data)		
Calculations:	0.055 lb/MMBtu * 71 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			17.10	tons/yr
NOx Emissions					
Emission Factor:	0.035	lb/MMBtu	(BACT and Vendor Data)		
Calculations:	0.035 lb/MMBtu * 71 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			10.88	tons/yr
SOx Emissions					
Emission Factor:	0.0093	lb/MMBtu	(H2S CEMS data - calculated)		
Calculations:	0.0093 lb/MMBtu * 71 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			2.89	tons/yr
VOC Emissions					
Emission Factor:	2.8	lbs/MMscf	(Webfire)		
Calculations:	2.8 lbs/MMscf * 571 MMscf/yr * 0.0005 tons/lb =			0.80	tons/yr
HAP Emissions	*See HAP worksheet (on file with Department)*			0.637	tons/yr

Vacuum Heater										
Size		27	MMBtu/hr							
Operating hours:		8760	hrs/year							
Potential Fuel Use		1090 Btu/scf * 217 MMscf/yr =							236530	MMBtu/yr
PM Emissions										
Emission Factor:		0.00051	lb/MMBtu		(Roy Huntley/Ron Meyers of Region 5, EPA)					
Calculations:		0.00051 lb/MMBtu * 27 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =							0.06	tons/yr
PM10 Emissions										
Emission Factor:		0.00051	lb/MMBtu		(Roy Huntley/Ron Meyers of Region 5, EPA)					
Calculations:		0.00051 lb/MMBtu * 27 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =							0.06	tons/yr
PM2.5 Emissions										
Emission Factor:		0.00042	lb/MMBtu		(Roy Huntley/Ron Meyers of Region 5, EPA)					
Calculations:		0.00042 lb/MMBtu * 27 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =							0.05	tons/yr
CO Emissions										
Emission Factor:		0.055	lb/MMBtu		(BACT and Vendor Data)					
Calculations:		0.055 lb/MMBtu * 27 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =							6.50	tons/yr
NOx Emissions										
Emission Factor:		0.035	lb/MMBtu		(BACT and Vendor Data)					
Calculations:		0.035 lb/MMBtu * 27 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =							4.14	tons/yr
SOx Emissions										
Emission Factor:		0.0093	lb/MMBtu		(H2S CEMS data - calculated)					
Calculations:		0.0093 lb/MMBtu * 27 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =							1.10	tons/yr
VOC Emissions										
Emission Factor:		2.8	lbs/MMscf		(Webfire)					
Calculations:		2.8 lbs/MMscf * 217 MMscf/yr * 0.0005 tons/lb =							0.30	tons/yr
HAP Emissions		*See HAP worksheet (on file with Department)*							0.242	tons/yr

Combined Feed Heater										
Size		54	MMBtu/hr							
Operating hours:		8760	hrs/year							
Potential Fuel Use		1090 Btu/scf * 434 MMscf/yr =							473060	MMBtu/yr
PM Emissions										
Emission Factor:		0.00051	lb/MMBtu		(Roy Huntley/Ron Meyers of Region 5, EPA)					
Calculations:		0.00051 lb/MMBtu * 54 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =							0.12	tons/yr
PM10 Emissions										
Emission Factor:		0.00051	lb/MMBtu		(Roy Huntley/Ron Meyers of Region 5, EPA)					
Calculations:		0.00051 lb/MMBtu * 54 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =							0.12	tons/yr
PM2.5 Emissions										
Emission Factor:		0.00042	lb/MMBtu		(Roy Huntley/Ron Meyers of Region 5, EPA)					
Calculations:		0.00042 lb/MMBtu * 54 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =							0.10	tons/yr
CO Emissions										
Emission Factor:		0.055	lb/MMBtu		(BACT and Vendor Data)					
Calculations:		0.055 lb/MMBtu * 54 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =							13.01	tons/yr
NOx Emissions										
Emission Factor:		0.035	lb/MMBtu		(BACT and Vendor Data)					
Calculations:		0.035 lb/MMBtu * 54 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =							8.28	tons/yr
SOx Emissions										
Emission Factor:		0.0093	lb/MMBtu		(H2S CEMS data - calculated)					
Calculations:		0.0093 lb/MMBtu * 54 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =							2.20	tons/yr
VOC Emissions										
Emission Factor:		2.8	lbs/MMscf		(Webfire)					
Calculations:		2.8 lbs/MMscf * 434 MMscf/yr * 0.0005 tons/lb =							0.61	tons/yr
HAP Emissions		*See HAP worksheet (on file with Department)*							0.485	tons/yr

Fractionator Feed Heater					
Size	38	MMBtu/hr			
Operating hours:	8760	hrs/year			
Potential Fuel Use	1090 Btu/scf * 305 MMscf/yr =			332450	MMBtu/yr
PM Emissions					
Emission Factor:	0.00051	lb/MMBtu	(Roy Huntley/Ron Meyers of Region 5, EPA)		
Calculations:	0.00051 lb/MMBtu * 38 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			0.08	tons/yr
PM10 Emissions					
Emission Factor:	0.00051	lb/MMBtu	(Roy Huntley/Ron Meyers of Region 5, EPA)		
Calculations:	0.00051 lb/MMBtu * 38 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			0.08	tons/yr
PM2.5 Emissions					
Emission Factor:	0.00042	lb/MMBtu	(Roy Huntley/Ron Meyers of Region 5, EPA)		
Calculations:	0.00042 lb/MMBtu * 38 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			0.07	tons/yr
CO Emissions					
Emission Factor:	0.055	lb/MMBtu	(BACT and Vendor Data)		
Calculations:	0.055 lb/MMBtu * 38 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			9.15	tons/yr
NOx Emissions					
Emission Factor:	0.035	lb/MMBtu	(BACT and Vendor Data)		
Calculations:	0.035 lb/MMBtu * 38 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			5.83	tons/yr
SOx Emissions					
Emission Factor:	0.0093	lb/MMBtu	(H2S CEMS data - calculated)		
Calculations:	0.0093 lb/MMBtu * 38 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			1.55	tons/yr
VOC Emissions					
Emission Factor:	2.8	lbs/MMscf	(Webfire)		
Calculations:	2.8 lbs/MMscf * 305 MMscf/yr * 0.0005 tons/lb =			0.43	tons/yr
HAP Emissions	*See HAP worksheet (on file with Department)*			0.341	tons/yr

<u>Hydrogen Plant #3</u>					
Size	134	MMBtu/hr	(tw o heaters, each rated at 67 MMBtu/hr)		
Operating hours:	8760	hrs/year			
Potential Fuel Use	330 Btu/scf * 3558 MMscf/yr =			1174140	MMBtu/yr
PM Emissions					
Emission Factor:	0.00051	lb/MMBtu	(Roy Huntley/Ron Meyers of Region 5, EPA)		
Calculations:	0.00051 lb/MMBtu * 134 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			0.30	tons/yr
PM10 Emissions					
Emission Factor:	0.00051	lb/MMBtu	(Roy Huntley/Ron Meyers of Region 5, EPA)		
Calculations:	0.00051 lb/MMBtu * 134 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			0.30	tons/yr
PM2.5 Emissions					
Emission Factor:	0.00042	lb/MMBtu	(Roy Huntley/Ron Meyers of Region 5, EPA)		
Calculations:	0.00042 lb/MMBtu * 134 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			0.25	tons/yr
CO Emissions					
Emission Factor:	0.03	lb/MMBtu	(BACT and Vendor Data)		
Calculations:	0.03 lb/MMBtu * 134 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			17.61	tons/yr
NOx Emissions					
Emission Factor:	0.051	lb/MMBtu	(BACT and Vendor Data)		
Calculations:	0.051 lb/MMBtu * 134 MMBtu/hr * 8760 hrs/year * 0.0005 tons/lb =			29.93	tons/yr
SOx Emissions					
Emission Factor:	0.06	lb/MMscf	(10% of AP-42 EF since heater w ill burn 10% NG/90% PSA)		
Calculations:	0.06 lb/MMscf * 660 MMscf/yr * 0.0005 tons/lb =			0.11	tons/yr
VOC Emissions					
Emission Factor:	0.0017	lbs/MMscf	(Webfire)		
Calculations:	0.0017 lbs/MMscf * 3558 MMscf/yr * 0.0005 tons/lb =			0.0030	tons/yr
HAP Emissions	*See HAP worksheet (on file with Department)*			0.601	tons/yr

SECONDARY EMERGENCY FLARE										
			Ignition Fuel	**Sweep Gas**			**Flare Gas**			
	Pilot Size (MMBtu/hr)=		0.3	N/A	Design size (lbs/hrs) =		30,625			
	Operation (hrs/yr) =		8,760	N/A	Operation (hrs/yr) =		9			
	Avg. Fuel HV (Btu/scf) =		1,020	N/A	Avg. HV (Btu/lbs) =		51,628			
	Fuel Use (MMscf/yr) =		2.576	3.963	Flare Gas (MMBtu/yr) =		14,230			
	2012 Average CC =		0.69	N/A	Flare Gas (L/yr) =		78,828,792			
	2012 Average MW =		17.06	N/A						
POLLUTANTS	**NATURAL GAS EMIS. FACTOR**				**FLARE EMIS. FACTOR**			**TOTAL EMISSIONS**		
CRITERIA POLLUTANTS										
	(AP-42 Sec. 1.4)		(lbs/yr)	(lbs/yr)	(AP-42 Sec. 13.5)		(lbs/yr)	(lbs/yr)	(lb/hr)	(tpy)
TSP	7.6	lbs/MMscf	19.58	30.12	0.00	ug/L	0.00	50	0.01	0.02
PM_{10}	7.6	lbs/MMscf	19.58	30.12	0.00	ug/L	0.00	50	0.01	0.02
$PM_{2.5}$	7.6	lbs/MMscf	19.58	30.12	0.00	ug/L	0.00	50	0.01	0.02
NO_X	100	lbs/MMscf	257.65	396.30	0.068	lbs/MMBtu	968	1,622	0.19	0.81
VOC	5.5	lbs/MMscf	14.17	21.80	0.140	lbs/MMBtu	1,992	2,028	0.23	1.01
CO	84	lbs/MMscf	216.42	332.89	0.370	lbs/MMBtu	5,265	5,814	0.66	2.91
SO_2	0.6	lbs/MMscf	1.55	2.38	2,171	lbs/hr	19,539	19,543	2.23	9.77
GREENHOUSE GAS POLLUTANTS										
	(40 CFR Part 98 Tier 3)		(metric tons)	(metric tons)				(metric tons)	(lb/hr)	(tpy)
CO_2	50.8	tonnes/MMscf	130.91	201.35				332	83.62	366.25
CH_4	3.06E-03	tonnes/MMscf	0.01	0.01				0.02	0.01	0.02
N_2O	6.12E-04	tonnes/MMscf	0.00	0.00				0.004	0.001	0.004
Total CO_2e			**131.56**	**202.36**				**333.92**	**84.04**	**368.08**

Notes:
Avg. Fuel HV for natural gas assumed to be 1,020 Btu/scf. Fuel Use (MMscf/yr) = Size (MMBtu/hr) x Operating Time (hrs/yr) / Avg. Fuel HV (Btu/scf) Fuel use for sweep gas provided by facility engineering department. TSP, PM_{10} and $PM_{2.5}$ emission factors based on smokeless flare design. Emissions (lbs/yr) = Fuel Use (MMscf/yr) x EF (lbs/MMscf) Flare gas information provided by facility engineering department. Flare operating hours assumed to be 45 minutes per event and 12 events per year. Flare Gas (MMBtu/yr) = Design size (lbs/hr) x Operation (hrs/yr) x Avg. HV (btu/lbs) Flare Gas (L/yr) = Design size (lbs/hr) x Operation (hrs/yr) x Flare Gas Volume (1,010 ft^3/lbmol) / Molecular Weight of Gas (100 lb/lbmol) Flare Gas Volume = 10.73 ft^3-psia/deg R-lbmol x T (1223.67 deg R) / P (13 psia) = 1,010 ft^3/lbmol NO_X, VOC, and CO - Emissions (lbs/yr) = Flare Gas (MMBtu/yr) x EF (lbs/MMBtu) SO_2 emission factor calculated using the depressurization flow rate and the maximum anticipated mole percent of H_2S. SO_2 - Emissions = SO_2 (lbs/hr) x Operation (hrs/yr) Greenhouse gas emissions from the ignition fuel and sweep gas estimated using the 40 CFR Part 98 Subpart C Tier 3 Methodology. Greenhouse gas emissions from the flare gas were not estimated due to lack of information.

Fugitive Emissions

VOC Emissions

Component Type	Valves			Connectors[a]		Compressors	Pumps		PRVs	OE Lines	SC	Drains[b]
Service	Gas	Light Liq.	Heavy Liq.	Gas+LL	Heavy Liq.	Gas	Light Liq.	Heavy Liq.	Gas	All	All	All
Average Emission Factor[c]	0.0268	0.0109	0.0023	0.00025	0.00025	0.636	0.114	0.021	0.16	0.0023	0.015	0.029
Percent Control[d]	89	89	50	81	50	50	65	50	95	0	0	75
Controlled Emission Factor	0.00295	0.00120	0.00115	0.000048	0.000125	0.318	0.0399	0.0105	0.008	0.0023	0.015	0.007
Number of components	1339	290	1236	4887	3708	1	10	25	34	0	6	101
Emissions, kg/hr	3.95	0.35	1.42	0.23	0.46	0.32	0.40	0.26	0.27	0.00	0.09	0.73
Emissions, lb/hr	8.69	0.77	3.13	0.51	1.02	0.70	0.88	0.58	0.60	0.00	0.20	1.60
Emissions, TPY	38.1	3.4	13.7	2.2	4.5	3.1	3.8	2.5	2.6	0.0	0.9	7.0
							Total Components:				11536	

Total Components VOC, lb/hr	**17.08**
Total Components VOC, TPY	**74.80**
Total Drains VOC, lb/hr	**1.60**
Total Drains VOC, TPY	**7.03**

[a] Connector counts based on three times the value of the valve count in units not regulated by HON

[b] Drain emissions estimated using AP-42 Table 5.1-3 factor of 450 kg/day for 650 components, or 0.029 kg/hr/source.

[c] Emission factors (kg/hr/source) from Table 2-2 of *EPA Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017)*, November 1995

[d] Gas/LL control effectiveness based on number of components screened greater than 50 ppm. HL control based on regular AVOs. Drain controls include p-traps and water seals.

Rail Car Loading

Emission factor (lb/1,000 gal loaded)				
	EF = 12.46 x S x P x M / T x (1-(eff/100))			(AP42 factor from Transportation & Marketing, Section 5.2)
Actual 2012 Railcar Loading VOC Emissions				
	Distillates	**Naphtha**	**Gasoline**	
	(uncontrolled)	(controlled)	(controlled)	
S	0.6	0.6	0.6	(saturation factor for submerged loading with dedicated normal service railcar)
P	0.0043	2.5	4.2	(true vapor pressure, at average annual temp of 46 F; interpolated from AP-42)
M	130	70	65	(molecular weight of vapors - interpolated from AP-42)
T	506	506	506	(average annual temp, degrees R @ 46 degrees F)
eff	0	99.2	99.2	(control efficiency x collection efficiency = 99.98% control (9/2011 test) x 99.2% collection (from AP-42)
EF =	0.01	0.02	0.03	lb/1000 gallons loaded
Volume loaded (gal)				
	7,514,681	6,360,900	3,805,645	
Loading Emissions				
	62.06	131.57	122.80	lbs VOC/yr
	0.03	0.07	0.06	tpy

Railcar Loading VOC Emissions Estimates - Expansion Project				
	Distillates	**Naphtha**	**Gasoline**	
	(uncontrolled)	(controlled)	(controlled)	
S	0.6	0.6	0.6	(saturation factor for submerged loading with dedicated normal service railcar)
P	0.0043	2.5	4.2	(true vapor pressure, at average annual temp of 46 F; interpolated from AP-42)
M	130	70	65	(molecular weight of vapors - interpolated from AP-42)
T	506	506	506	(average annual temp, degrees R @ 46 degrees F)
eff	0	99.2	99.2	(control efficiency x collection efficiency = 99.98% control (9/2011 test) x 99.2% collection (from AP-42)
EF =	0.01	0.02	0.03	lb/1000 gallons loaded
Volume loaded (gal)				
	160,000,000	34,000,000	12,000,000	
Loading Emissions				
	1321.45	703.28	387.22	lbs VOC/yr
	0.66	0.35	0.19	tpy

Rail Car (net emissions increase)

Net Emissions Increase				
	1259.39	571.70	264.42	lbs VOC/yr
	0.63	0.29	0.13	tpy

Note - vapor-phase concentration of methane assumed to be less than 0.5 volume percent. Assume zero percent methane emissions from railcar loading

V. Existing Air Quality

As of July 8, 2002, Cascade County is designated as an Unclassifiable/Attainment area for NAAQS for all criteria pollutants. Previous to that date, Calumet was located outside, but adjacent to, a CO nonattainment area in downtown Great Falls. On December 2, 1985, the Department of Environmental Quality (formerly Montana Department of Health and Environmental Sciences) and Calumet (formerly Montana Refining Company) signed a stipulation requiring Calumet to obtain an air quality permit and stipulating a permit emission limitation of 4,700 TPY CO, when considered in conjunction with control measures on other sources such as automobiles, would achieve compliance with ambient CO standards. This permit limits plant-wide CO emissions to 4,700 TPY.

In 1993, the Department conducted preliminary ambient air quality modeling for SO_2 using the COMPLEX1 and ISC2 models and meteorological data collected from the Great Falls Airport assuming 7 tons per day of SO_2 emissions. The results of the model previously demonstrated that at 7 tons per day of emissions, this facility causes a violation of the state and federal SO_2 ambient standards. As a result, Calumet was limited to 5.25 tons per day of plant-wide refinery SO_2 emissions (MAQP #2161-06) in the first step of a plan to achieve attainment. In April 1998, Calumet submitted additional modeling to demonstrate compliance with the NAAQS for SO_2. In June 1999, this modeling, and the permit application were determined to be complete. The permitting action established limitations that demonstrate compliance with the NAAQS and MAAQS for SO_2. The facility is now limited to 4.15 tons per rolling 24-hours of plant-wide refinery SO_2 emissions (or 1515 TPY). An ambient air-monitoring plan will continue to be used to monitor SO_2 emissions.

VI. Ambient Air Impact Analysis

An ambient air impact analysis was not required for this permit action because the significant net increase was less than the modeling thresholds. However, the Department believes that the impacts associated with this action would be minor, and the proposed expansion project would not cause or contribute to a violation of any ambient air quality standard.

VII. Taking or Damaging Implication Analysis

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

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

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

VIII. Environmental Assessment

An environmental assessment, required by the Montana Environmental Policy Act, was completed for this project. A copy is attached.

DEPARTMENT OF ENVIRONMENTAL QUALITY
Permitting and Compliance Division
Air Resources Management Bureau
1520 East Sixth Avenue
P.O. Box 200901
Helena, Montana 59620-0901
(406) 444-3490

FINAL ENVIRONMENTAL ASSESSMENT (EA)

Issued For: Calumet Montana Refining, LLC (Calumet)
1900 10th Street North East
Great Falls, MT 59404

Montana Air Quality Permit Number (MAQP): #2161-28

Preliminary Determination Issued: March 18, 2014
Department Decision Issued: April 25, 2014
Permit Final:

1. *Legal Description of Site*: Calumet is located at 1900 10th Street N.E. in Great Falls, Montana. The legal description of the site is the NE¼ of Section 1, Township 20 North, Range 3 East, Cascade County, Montana.

2. *Description of Project*: On October 3, 2013, the Montana Department of Environmental Quality – Air Resources Management Bureau (Department) received a permit application requesting a major modification under the New Source Review-Prevention of Significant Deterioration (NSR-PSD) program. As proposed, Calumet would increase the low sulfur fuels capacity at the existing refinery from 10,000 barrels per stream day (BPSD) crude throughput up to 30,000 BPSD while increasing yields of distillates, kerosene, diesel, and asphalt products.

   The expansion project would include the construction of four new processing units: a new crude unit that would process heavy sour crudes, a mild-hydrocracker (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 specific emitting units included with the expansion project would be: Hydrogen Plant #3 (equipped with two heaters and 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 secondary flare interconnected to the existing flare that would 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 hydrotreating unit (HTU) that currently block operates in both diesel and gas-oil service would become the kerosene HTU, and the existing kerosene HTU will become a Naptha HTU. Lastly, Calumet requested a federally enforceable operational limit on Boiler #1 and Boiler #2 to cap the oxides of nitrogen (NO_x) emissions. Conditional upon approval, Calumet would begin construction in the Summer of 2014.

3. *Objectives of Project*: The primary purpose of the project would be to increase the low sulfur fuels capacity at the refinery from 10,000 barrels per stream day (BPSD) crude throughput up to 30,000 BPSD while increasing yields of distillates, kerosene, diesel, and asphalt products.

4. *Additional Project Site Information*: This refinery has operated at this site since the 1930's. The refinery currently employs 115 people, and is located along the Missouri River in Great Falls, Montana.

5. *Alternatives Considered*: In addition to the proposed action, the Department considered the "no-action" alternative. The "no-action" alternative would deny issuance of the air quality preconstruction permit to the proposed facility. However, the Department does not consider the "no-action" alternative to be appropriate because Calumet demonstrated compliance with all applicable rules and regulations as required for permit issuance. Therefore, the "no-action" alternative was eliminated from further consideration.

6. *A Listing of Mitigation, Stipulations, and Other Controls*: A listing of the enforceable permit conditions and a permit analysis would be contained in MAQP #2161-28.

7. *Regulatory Effects on Private Property Rights*: The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined the permit conditions would be reasonably necessary to ensure compliance with applicable requirements and to demonstrate compliance with those requirements and would not unduly restrict private property rights.

8. *The following table summarizes the potential physical and biological effects of the proposed project on the human environment. The "no action alternative" was discussed previously.*

		Major	Moderate	Minor	None	Unknown	Comments Included
A.	Terrestrial and Aquatic Life and Habitats			X			yes
B.	Water Quality, Quantity, and Distribution			X			yes
C.	Geology and Soil Quality, Stability, and Moisture			X			yes
D.	Vegetation Cover, Quantity, and Quality			X			yes
E.	Aesthetics			X			yes
F.	Air Quality			X			yes
G.	Unique Endangered, Fragile, or Limited Environmental Resource			X			yes
H.	Demands on Environmental Resource of Water, Air, and Energy			X			yes
I	Historical and Archaeological Sites				X		yes
J.	Cumulative and Secondary Impacts			X			yes

SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS: The following comments have been prepared by the Department.

A. Terrestrial and Aquatic Life and Habitats

Impacts on terrestrial and aquatic life would be minor. Calumet is an existing refinery operation proposing to expand at their current location. The refinery property is fenced for limited outside access. Because the expansion project would occur within the existing refinery but is currently located near the river's edge, the Department believes there would be minor additional impacts to terrestrial or aquatic life and habitats. During construction there would be some changes to the existing landscape; however, these would be temporary and would occur within the existing refinery boundary. Once the expansion project is complete, there would be an increase in emissions of several criteria pollutants, but overall, the associated impacts to terrestrial and aquatic life and habitats would be minor.

B. Water Quality, Quantity, and Distribution

Any impacts on water quality, quantity or distribution, if any, would be minor because this permit modification would require little, if any, additional water. There would be a potential for impacts to groundwater or storm water due to spills and leaks, but these risks should be addressed in the facility's Spill Prevention Control Countermeasure (SPCC) plan. Additionally, all surface water and collected groundwater would continue to be routed to the refinery wastewater system for treatment prior to discharge to the city's system. With the expansion project, Calumet also proposes to add a larger dissolved air floatation at the wastewater plant and a second-water stripper and several modifications to the existing sewer to accommodate the project. The Department determined that the overall characteristics of the area would not change as a result of the proposed project and any associated impacts would be minor.

C. Geology and Soil Quality, Stability, and Moisture

On March 6, 2014, Department (Hazardous Waste Section) received a request from Calumet to dispose of "corrective action management unit" (CAMU)-eligible soil to a permitted hazardous waste landfill. The soil excavation would be conducted in or near the area of the expansion project pursuant to a Department approved work plan in order to mitigate impacts to human health and groundwater. The soil is contaminated from historical activities at the refinery and upon excavation will be managed as a hazardous waste. Calumet proposed to remove and/or re-locate some of their tanks (e.g. #122, #48, #53, #54, and #52) and remediate the area prior to expansion.

Once the soils are removed and mitigated, the proposed permit modification would have minor impacts on geology and soil quality, stability and moisture because deposition of air pollutants on soils would be minor (see Section 8.F of this EA). The refinery expansion would occur within the existing facility boundaries. During construction, there would be disturbance to the area. However, pollutants would be widely dispersed before settling upon vegetation and surrounding soils (see Section 8.D of this EA). Therefore, any additional effects upon geology and soil quality, stability, and moisture at this site would be minor.

D. Vegetation Cover, Quantity, and Quality

The expansion project would be located in an industrial area within an existing refinery. Overall, Calumet noted that the project would result in an increase of all criteria pollutants and greenhouse gas (GHG) emissions. However, the Great Falls area is known for high winds and any emissions would be well dispersed. Additionally, there are no known unique, rare, threatened or endangered plant species located at the refinery. Therefore, the Department determined that any associated impacts upon vegetation would be minimal.

E. Aesthetics

During construction, there would be disturbances to the surrounding aesthetics. The existing operation would be visible and could create additional noise while operating; however, impacts to aesthetics associated with this project would result in temporary and minor changes to aesthetics. The expansion project would include several new emitting units; however, MAQP #2161-28 would include conditions to control emissions, including visible emissions. Therefore, impacts to area aesthetics as a result of the proposed permit modification would be minor.

F. Air Quality

Air quality impacts from the proposed project would be minor. MAQP #2161-28 would include conditions to maintain the ambient standards and any additional pollutant deposition from the proposed project would be minimal. The pollutants emitted are mainly gaseous, and would be widely dispersed (from factors such as wind speed and wind direction) and would have minimal deposition on the surrounding area (due to site topography of the area and minimal vegetative cover in the area). Therefore, air quality impacts in this area as a result of this permit action would be minor.

G. Unique Endangered, Fragile, or Limited Environmental Resources

Since a refinery has operated at this site since the 1930's and the area is fenced, the permit modification would not result in any additional disturbance to unique endangered, fragile, or limited environmental resources. The Department determined that the proposed project would have minor impacts to the surroundings, and little to no impacts, on any species of concern.

H. Demands on Environmental Resources of Water, Air, and Energy

According to Calumet, there would be no additional demands on water resources due to this permit modification. There will be impacts to air resources with the expansion project. Air pollutants generated due to this modification would be limited and dispersed (see Section 8.F of this EA). There would be likely be change in energy requirements with the expansion project, but would not require the facility to upgrade to electrical utilities. Overall, for this action, any impacts of the proposed project to water, air, and energy resources would be minor.

I. Historical and Archaeological Sites

The proposed project would occur within the boundaries of the Calumet facility, a previously disturbed industrial site that has been in operation since the 1930s. The Montana State Historic Preservation Office previously informed the Department that there would be a low likelihood of adverse disturbance to any known archaeological or historic site, given previous industrial disturbance within a given area. Because there would be no additional ground disturbance, there would be no known effect on any historic or archaeological site.

J. Cumulative and Secondary Impacts

Additional emissions generated from the proposed project would result in minor impacts to the area because the proposed equipment is located within the existing refinery facility, which has other sources of emissions that are much larger. This modification would be minor in comparison and the overall, cumulative and secondary impacts to the physical and biological aspects of the human environment would be minor.

9. *The following table summarizes the potential economic and social effects of the proposed project on the human environment. The "no action alternative" was discussed previously.*

		Major	Moderate	Minor	None	Unknown	Comments Included
A.	Social Structures and Mores			X			yes
B.	Cultural Uniqueness and Diversity				X		yes
C.	Local and State Tax Base and Tax Revenue			X			yes
D	Agricultural or Industrial Production				X		yes
E.	Human Health			X			yes
F.	Access to and Quality of Recreational and Wilderness Activities			X			yes
G	Quantity and Distribution of Employment			X			yes
H.	Distribution of Population			X			yes
I.	Demands for Government Services			X			yes
J.	Industrial and Commercial Activity		X				yes
K.	Locally Adopted Environmental Plans and Goals			X			yes
L.	Cumulative and Secondary Impacts			X			yes

SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS: *The following comments have been prepared by the Department.*

A. Social Structures and Mores

The proposed project would cause little to no disruption to the social structures and mores in the area because the modification would occur within an existing industrial source. Construction projects within the refinery would be visible and would cause some temporary disturbance to the surroundings. However, the facility would be required to operate according to the conditions that would be placed in MAQP #2161-28. There are no known native or traditional communities that would be affected by the proposed project operations and minor impacts upon social structures or mores would result.

B. Cultural Uniqueness and Diversity

The predominant use of the area is an existing refinery. Because the predominant use of this area has historically been refinery operations, and the fact that the refinery's operation would result in minor changes and limited emissions, there would be minor impacts resulting from this permit modification. Therefore, the cultural uniqueness and diversity of the area would not be impacted by this permit action.

C. Local and State Tax Base and Tax Revenue

The proposed project would result in a $400 million investment including equipment, labor and related construction costs. Calumet estimated that during construction, the construction workforce could exceed 500. Once construction is completed, Calumet would anticipate that the expansion would result in an increase of permanent employees at the refinery to 150 people. The Department believes there would be impacts to the local and state tax base and revenue but most would be expected to be positive to the local economy. Because the proposed project would be located at an existing industrial source, any additional impacts on the local and state tax base and tax revenue would be minor.

D. Agricultural or Industrial Production

The permit modification would occur within an existing refinery that is located in an industrial/commercial area. The project would result in temporary ground disturbance. There would be no impact to existing agricultural land as expansion would be located within the already established industrial area. There are no expected effects on agricultural production, and minor effects on industrial production.

E. Human Health

MAQP #2161-28 would incorporate conditions to ensure that the proposed permit modification would be operated in compliance with all applicable air quality rules and standards. These rules and standards are designed to be protective of human health. As described in Section 8.F of this EA, any additional emissions that would result would be minimized by conditions in MAQP #2161-28. Therefore, only minor impacts would be expected on human health from the proposed project.

F. Access to and Quality of Recreational and Wilderness Activities

This project would have minor additional impacts on recreational or wilderness activities because the expansion project would be constructed within an existing facility. The Calumet refinery (as well as the proposed expansion) is adjacent to the Rivers Edge Trail. In 1998, a project was completed to upgrade a major sewer line at the north end of the 9th Street bridge which included a total rebuild of the trail south of the refinery complete with a trail underpass of Ninth Street North, and a tunnel behind the bulkhead of the abandoned 10th Street Bridge to establish formal public use and access. Additionally, Calumet has a use agreement with the City of Great Falls "for the purpose of installing, operating and maintaining a boat ramp solely for the purpose of emergency access to the Missouri River." The City of Great Falls also granted Calumet access to the River's Edge Trail at certain times for training purposes or in the event of an emergency. However, because Calumet is an existing facility, proposing to expand at the existing location, the project would result in minor changes in access to and quality of recreational and wilderness activities.

G. Quantity and Distribution of Employment

There would be several temporary employment opportunities (up to 500) that would result from the facility's expansion project. Calumet estimated that the expansion would result in an increase in employment (total of 150 people) at the refinery. No individuals would be expected to permanently relocate to this area of operation as a result of the proposed project. Therefore, minor effects upon the quantity and distribution of employment in this area would be expected.

H. Distribution of Population

During construction there would be some temporary construction employees on site, but Calumet proposed to use local contractors and workforce to the extent possible. Calumet would not anticipate that any individuals would be expected to permanently relocate to this area as a result of the proposed project. Therefore, the proposed project would have minor, if any, impact to the normal population distribution in the area of operation.

I. Demands of Government Services

Minor government services would be required for acquiring the appropriate permits for the proposed project and verifying compliance with the permits that would be issued. However, because this is an existing facility, the Department would not anticipate an increase in the level of government services that would be provided. Therefore, the Department believes that the demands for government services would be minor.

J. Industrial and Commercial Activity

Calumet's proposed project would occur at the existing refinery. Calumet expansion project would increase the low sulfur fuels capacity at the refinery from 10,000 BPSD crude throughput up to 30,000 BPSD while increasing yields of distillates, kerosene, diesel, and asphalt products. The expansion project would include the construction of four new processing units: a new crude unit that would process heavy sour crudes, an 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. These changes would result in an increase of industrial and commercial activity, but the expansion would occur within the existing refinery. The Department believes there would be moderate change to the existing industrial and/or commercial activity in the area due to the increase in production at the existing refinery.

K. Locally Adopted Environmental Plans and Goals

On February 18, 2014, Calumet held a public open house to discuss the project. State and local officials were also available to discuss the project and answer any questions associated with the refinery's expansion project. MAQP #2161-28 would contain limits for protecting air quality and to keep facility emissions in compliance with any applicable ambient air quality standards, which would be consistent with any locally adopted environmental plan or goal for operating at this proposed site. The Department believes that minor impacts would result from this project.

L. Cumulative and Secondary Impacts

The proposed project would cause minor cumulative and secondary impacts to the social and economic aspects of the human environment in the immediate area of operation. Because the source is an existing operation many of the cumulative or secondary impacts have been mitigated over the years in the existing air quality permit. Additional conditions and limitations would be added to the existing MAQP to mitigate any other future impacts. The Department believes that the permit modification would not result in any additional permanent increases in traffic to the immediate area. Initially, there would be an increased demand for governmental services (permitting and compliance); however, once construction is complete there would be no additional cumulative impacts. The Department believes there would be the potential for positive impacts to the tax base and local economy. Thus, only minor and temporary cumulative and secondary effects would result.

Recommendation: An Environmental Impact Statement (EIS) is not required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: All potential effects resulting from construction and operation of the proposed facility are negligible or minor; therefore, an EIS is not required.

Other groups or agencies contacted or which may have overlapping jurisdiction: Montana Department of Environmental Quality - Permitting and Compliance Division (Industrial and Energy Minerals Bureau); Montana Natural Heritage Program; and the State Historic Preservation Office (Montana Historical Society).

Individuals or groups contributing to this EA: Montana Department of Environmental Quality (Air Resources Management Bureau), Montana State Historic Preservation Office (Montana Historical Society).

EA prepared by: Ed Warner
Date: March 17, 2014