Montana Department of
ENVIRONMENTAL QUALITY

Brian Schweitzer, Governor

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October 19, 2012

Monica Mainland – Refinery Manager
ExxonMobil Refining & Supply Company – Billings Refinery
P.O. Box 1163
Billings, Montana 59103-1163

Dear Ms. Mainland:

Montana Air Quality Permit #1564-26 is deemed final as of October 19, 2012, by the Department of Environmental Quality (Department). This permit is for a petroleum refinery. All conditions of the Department's Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

For the Department,

Julie A Merkel

Ed Warner

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

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JM:EW
Enclosure

Montana Department of Environmental Quality
Permitting and Compliance Division

Montana Air Quality Permit #1564-26

ExxonMobil Corporation
ExxonMobil Refining & Supply Co.
Billings Refinery
P.O. Box 1163
Billings, MT 59103-1163

October 19, 2012

MONTANA AIR QUALITY PERMIT

Issued to:	ExxonMobil Corporation ExxonMobil Refining & Supply Co. Billings Refinery P.O. Box 1163 Billings, MT 59103-1163	MAQP: #1564-26 Administrative Amendment (AA) Request Received: 8/6/12 Department Decision on AA: 10/3/12 Permit Final: 10/19/12 AFS #: 111-0013

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

Section I: Permitted Facilities

A. Plant Location

The ExxonMobil – Billings Refinery is located at 700 Exxon Road in Billings, Montana. The Yellowstone River forms the northern and northeastern boundaries, and Interstate 90 lies along the southern border. Refinery units and storage tanks lie in the southern half of Section 24 and the northern half of Section 25, Township 1 North, Range 26 East, in Yellowstone County, Montana. The active refinery occupies approximately 380 acres on a level plot.

B. Permitted Facility

This permit covers all existing sources of air contaminants at the above-described petroleum facility. A list of permitted equipment can be found in the permit analysis section of this permit. The refinery also includes the bulk marketing distribution terminal, which stores and transfers petroleum products (gasoline and distillate) received from the refinery and distributes them to regional markets via tank truck. The terminal is located adjacent to and south of the refinery and operates under MAQP #2967-00, but is considered one facility with the refinery for permitting evaluations.

C. Current Permit Action

On August 6, 2012, the Department received correspondence from ExxonMobil requesting that the Montana Department of Environmental Quality – Air Resources Management Bureau (Department) amend the MAQP to change the emitting unit ID and description of the portable diesel-fired air compressor engine SE8 from “SLEB Backup Air Compressor (SL/Port2)” to “Boiler House Backup Air Compressor (UT/Port2)”. The compressor was originally located at the SLEB unit but will now be located at the boiler house.

Section II. Limitations and Conditions

A. General Facility Conditions

1. ExxonMobil shall, any time the Yellowstone Energy Limited Partnership (YELP) facility is operating, send all of its coker process gas to either one or both of YELP’s boilers. During startup and shutdown conditions at YELP, ExxonMobil shall supply the maximum amount of coker process gas that YELP can accept.

2. A refinery-wide block hourly limit of 0.96 pounds (lb) of sulfur in fuel per million British thermal units (MMBtu) fired shall be adhered to at all times. In the event ExxonMobil fails to meet the hourly limit of 0.96 lb of sulfur per MMBtu fired, ExxonMobil shall immediately notify YELP of this occurrence. After such an occurrence, ExxonMobil shall also provide subsequent notification to YELP when it has met the hourly sulfur-in-fuel limitation for three-consecutive hourly periods.

3. Any time ExxonMobil diverts process coker gases from YELP, ExxonMobil shall report said diversion to the Department within 24 hours or during the next working day. This information shall also be included in the quarterly continuous emission monitors (CEMS) sulfur-in-fuel report and include period(s) of diversion, quantity of sulfur oxide emissions, reason(s) for diversion(s), and corrective measures taken to prevent recurrence.

4. ExxonMobil shall not fire fuel oil, except during periods of natural gas curtailment. Nothing herein is intended to limit, or shall be interpreted as limiting: (i) the use of torch oil in an FCC Unit Regenerator to assist in starting, restarting, maintaining hot standby, or maintaining regenerator heat balance; or (ii) combustion of acid soluble oil in a combustion device (ARM 17.8.749, Consent Decree paragraph 60).

5. ExxonMobil shall at all times and to the extent practicable, including during periods of startup, shutdown, upset and/or malfunction, implement good air pollution control practices to minimize emissions from its Flaring Devices, in a manner consistent with the requirements imposed by 40 Code of Federal Requirements (CFR) 60.11(d) (ARM 17.8.749, Consent Decree Paragraph 70).

6. ExxonMobil shall at all times and to the extent practicable, including during periods of startup, shutdown, upset and/or malfunction, implement good air pollution control practices to minimize emissions from the main and turnaround flares, in a manner consistent with requirements imposed by 40 Code of Federal Requirements (CFR) 60.11(d) (ARM 17.8.749, Consent Decree Paragraph 70).

7. ExxonMobil shall comply with all the applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR 60, Subpart A and Subpart J – Standards of Performance for Petroleum Refineries. 40 CFR 60, Subpart J will apply to the refinery as follows, except during periods of startup, shutdown, or Malfunction as defined by 40 CFR 60.2 (ARM 17.8.340 and 40 CFR 60, Subpart J; and Consent Decree Paragraphs 43, 59, 71 & 73):

   a. The FCC Unit catalyst regenerator shall comply with the applicable emission limitations (Particulate Matter (PM), carbon dioxide (CO), and opacity, but not sulfur dioxide (SO_2)) after the dates outlined in the Consent Decree;

   b. ExxonMobil shall treat or re-route SWS T-23 overhead gas combusted in the FCC Unit CO Boiler by no later than December 31, 2008, or as amended in the consent decree;

   c. The FCC Unit CO Boiler shall comply with the Alternative Monitoring Plan (AMP) for Unsaturated Light Ends Merox Vent stream (Disulfide Separator Offgas (DSO) stream);

   d. Each heater and boiler used to combust refinery fuel gas is an "affected facility", as that term is used in 40 CFR 60, Subparts A and J for fuel gas combustion devices and shall be subject to and comply with the requirements of NSPS Subparts A and J, except the Pipestill (Crude Fractionator) Heater F-1, which shall comply with the requirements by December 31, 2008, or as amended in the consent decree. Prior to December 31, 2008, or as amended in the consent decree, the Pipestill Heater F-1 shall comply with the emission limitation specified by 40 CFR 60.104(a)(1) at all times, except when SWS T-23 ammonia overhead gas is combusted in the unit as permitted by pertinent provisions of the Montana State Implementation Plan.

e. By December 13, 2009, or as amended in the consent decree, each NSPS Flaring Device will be considered an "affected facility" as that term is used in NSPS, 40 CFR 60, Subparts A and J, for fuel gas combustion devices. ExxonMobil shall comply with the NSPS Subparts A and J for each NSPS Flaring Device by using one of the methods specified in the Consent Decree paragraph 73.

f. By no later than September 30, 2010, the main and turnaround flares shall meet NSPS A and J, for fuel gas combustion devices as specified in the Consent Decree, paragraphs 70 and 71.

g. By no later than September 30, 2010, ExxonMobil shall install and operate a continuous monitor pursuant to 40 CFR 60.105(a)(4) or with a parametric monitoring system approved by EPA as an alternative monitoring system under 40 CFR 60.13(i) (Consent Decree Paragraph 73.a.iii).

8. ExxonMobil shall comply with all the applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR 60, Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry, as it applies to this refinery (ARM 17.8.340 and 40 CFR 60, Subpart VV).

9. ExxonMobil shall comply with all the applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR 60, Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or before November 7, 2006, as it applies to this refinery (ARM 17.8.340 and 40 CFR 60, Subpart GGG).

10. ExxonMobil shall comply with all the applicable standards and limitations, and the monitoring, recordkeeping and reporting requirements contained in 40 CFR 60, Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, as it applies to this refinery (ARM 17.8.340 and 40 CFR 60, Subpart GGGa).

11. ExxonMobil shall comply with all the applicable standards and limitations, and the monitoring, recordkeeping and notification requirements of 40 CFR 63, Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as it applies to this refinery. This requirement includes the vapor control equipment installed on Tank #309 (ARM 17.8.342 and 40 CFR 63, Subpart CC).

12. ExxonMobil shall comply with all the applicable standards and limitations, and the monitoring, recordkeeping and notification requirements of 40 CFR 63, Subpart UUU – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as it applies to this refinery (ARM 17.8.342 and 40 CFR 63, Subpart UUU).

B. Polymer Modified Asphalt (PMA) Unit

1. ExxonMobil shall maintain the operating temperature of the wetting/mixing tank below the smoking point of asphalt. ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere, from the wetting/mixing tank, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 and 17.8.752).

2. All valves used shall be high quality valves containing high quality packing (ARM 17.8.752).

3. All open-ended valves shall be of the same quality as the valves described above, and they shall have plugs or caps installed on the open end (ARM 17.8.752).

4. All pumps and mills used in the PMA unit shall be equipped with standard high quality single seals (ARM 17.8.752).

5. Flanges shall be equipped with process-compatible gasket material.

6. All applicable requirements of ARM 17.8.340, which reference 40 CFR Part 60, Standards of Performance for New Stationary Sources and Subpart GGG – Equipment Leaks of VOC in Petroleum Refineries, shall apply to the PMA process unit and any other equipment, as appropriate. A monitoring and maintenance program, as described under New Source Performance Standards (40 CFR Part 60, Subpart VV), shall be instituted.

7. The PMA unit may process either non-polymerized or polymer modified asphalt.

8. Once the PMA unit is modified, the PMA tanks (Tanks #72, #73, #76 & #77) combined shall not exceed 28.3 tons of Volatile Organic Compound (VOC) emissions per 12-month rolling period (ARM 17.8.749).

9. Once the PMA unit is modified, the PMA loading operations shall not exceed 22.7 tons of VOC emissions per 12-month rolling period (ARM 17.8.749).

10. Once the PMA unit is modified, the PMA Tanks and the PMA loading operations shall be limited to a combined total of 46.6 tons of VOC emissions per 12-month rolling period (ARM 17.8.749).

11. Once Tank #55 is modified for asphalt service, Tank #55 shall be controlled by a VOC coalescer (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60, Subpart UU).

12. Once Tank #55 is modified for asphalt service, Tank #55 shall be limited to 0% opacity except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown (ARM 17.8.340 and 40 CFR 60, Subpart UU).

C. D-4 Drum Atmospheric Vent Stack

1. ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere from the D-4 drum atmospheric vent stack that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

2. The D-4 drum atmospheric vent stack shall have steam injection capability and shall be used whenever hydrogen sulfide (H_2S) is being released or is expected to be released from a process unit to the D-4 drum (ARM 17.8.749).

D. FCC Unit and CO Boiler Stack

1. ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere, from the FCC CO Boiler stack, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes, except as allowed under the rule (ARM 17.8.304).

2. ExxonMobil shall not cause or authorize emissions to be discharged from the FCC Unit catalyst regenerator, measured at the CO Boiler stack, gases that exhibit an opacity of 30% opacity, except for one 6-minute average opacity reading in any 1 hour period (ARM 17.8.749; ARM 17.8.340 and 40 CFR 60, Subpart J; and Consent Decree paragraph 43).

3. ExxonMobil shall install and operate a third-stage cyclone on the FCC Unit, and take any additional steps necessary, in order to comply with a PM emission limit of 1.0 lb of PM per 1,000 lb of coke burned by no later than December 31, 2008, or as amended in the consent decree, unless ExxonMobil accepts an FCC PM limit of 0.5 lbs per 1000 lbs coke burned (ARM 17.8.749; ARM 17.8.340 and 40 CFR 60, Subpart J; and Consent Decree paragraph 34 and 35).

4. ExxonMobil shall comply with 500 parts per million, volumetric dry (ppmvd) CO corrected to 0% oxygen (O_2) on a 1-hour average basis on the FCC Unit (ARM 17.8.340 and 40 CFR 60, Subpart J and Consent Decree paragraph 39).

5. ExxonMobil shall operate the FCC Unit in a Full Burn Operation and comply with Consent Decree paragraphs 29a and 29b which addresses implementing a SO_2 emissions control program and establishing a SO_2 emission limit unless and until ExxonMobil accepts FCC Unit SO_2 limits of 25 ppmvd on a 365-day rolling average and 50 ppmvd on a 7-day rolling average basis (both at 0% O_2) (ARM 17.8.749, Consent Decree Paragraphs 29 – 30).

6. By no later than December 31, 2008, or as amended in the consent decree, ExxonMobil shall comply with the following nitrogen oxides (NO_x) emission limits on the FCC Unit (ARM 17.8.749, Consent Decree paragraph 17b):

   a. 40 ppmvd at 0% O_2 on a 365-day rolling average basis; and

   b. 80 ppmvd at 0% O_2 on a 7-day rolling average basis, other than FCCU NO_x emissions during a period of natural gas curtailment when fuel oil is burned. During such period of natural gas curtailment, ExxonMobil shall comply with an alternate short-term NO_x limit of 120 ppmvd at 0% O_2 on a 24-hour rolling average basis.

E. F-2 Crude/Vacuum Heater Stack

ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere from the F-2 Crude/Vacuum Heater stack that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes, except as allowed under the rule (ARM 17.8.304).

F. Furnace F-1201

1. Ultra Low NO_X Burners (ULNB) shall be used in furnace F-1201 to control NO_X emissions. The NO_X emissions shall not exceed 5.94 pounds per hour (lb/hr) and 0.060 pounds per million British thermal units (lb/MMBtu) (ARM 17.8.752).

2. The CO emissions from furnace F-1201 shall not exceed 7.77 lb/hr and 0.0785 lb/MMBtu (ARM 17.8.749).

3. ExxonMobil shall not cause or authorize to be discharged into the atmosphere from furnace F-1201, any visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

4. Furnace F-1201 shall not consume more than 811 million standard cubic feet (MMscf) of Refinery Fuel Gas (RFG) and natural gas combined during any rolling 12-month period (ARM 17.8.749).

G. Process Heater F-201 and Process Heater F-5

1. The NO_X emissions from F-201 shall not exceed 4.70 lb/hr (ARM 17.8.752).

2. The NO_X emissions from F-5 shall not exceed 6.27 lb/hr (ARM 17.8.752).

3. The combined NO_X emissions from F-5 and F-201 shall not exceed 33.30 tons per rolling 12-month period (ARM 17.8.752).

H. Furnace F-551

1. The NO_X emissions from F-551 shall not exceed 23.35 lb/hr (ARM 17.8.749).

2. ExxonMobil shall not cause or authorize to be discharged into the atmosphere from F-551, any visible emissions that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

3. The NO_X emissions from F-551 shall not exceed 75.55 tons per rolling 12-month period (ARM 17.8.752).

I. RFG Combustion Sources

1. The following combined emission limitations shall apply to furnace F-1201 and all other "Affected Equipment and Facilities" identified in Exhibit A of the Stipulation of the Department and ExxonMobil whenever the YELP facility is receiving ExxonMobil coker flue gas or whenever ExxonMobil's coker unit is not operating (ARM 17.8.749).

   a. Combined 3-hour emissions of SO_2 from the RFG combustion units shall not exceed 92.4 lb per 3-hour period, and

   b. Combined daily emissions of SO_2 from the RFG combustion units shall not exceed 739.2 lb per calendar day.

2. The following combined emission limitations shall apply to furnace F-1201 and all other “Affected Equipment and Facilities” identified in Exhibit A of the Stipulation of the Department and ExxonMobil whenever the YELP facility is not receiving ExxonMobil’s coker unit flue gas and ExxonMobil’s coker unit is not operating (ARM 17.8.749).

   a. Combined 3-hour emissions of SO_2 from the RFG combustion units shall not exceed 76.2 lb per 3-hour period, and

   b. Combined daily emissions of SO_2 from the RFG combustion units shall not exceed 609.6 lb per calendar day.

3. The RFG used in refinery heaters, boilers, and other fuel combustion devices shall not exceed 160 ppm_v (230 milligrams per dry standard cubic meter (mg/dscm)) or 0.10 grains per dry standard cubic foot (gr/dscf) of H_2S, (Consent Decree Paragraph 58 and 59; ARM 17.8.340 and 40 CFR 60, Subpart J), except:

   a. The Pipestill (Crude Fractionator) Heater F-1, which shall comply with the requirements by December 31, 2008, or as amended in the consent decree. Prior to December 31, 2008, or as amended in the consent decree, the Pipestill Heater F-1 shall comply with the emission limitation specified by 40 CFR 60.104(a)(1) at all times, except when SWS T-23 ammonia overhead gas is combusted in the unit as permitted by pertinent provisions of the Montana State Implementation Plan; and

   b. the FCC Unit CO Boiler, which shall comply by having the SWS T-23 overhead gas treated or rerouted by December 31, 2008, or as amended in the consent decree, and shall comply with the AMP for Unsaturated Light Ends Merox Vent stream (DSO Offgas stream).

J. Tank 26

VOC fugitive emissions from Tank 26 shall not exceed 515 tons per rolling 12-month period. The fugitive emissions shall be determined using the following equation (ARM 17.8.749).

W_{VOC} = 0.166677 lb/ft^3 * V_{inst} * [TVP / (12.9-TVP)]

Where:

W_{VOC} = Mass of hydrocarbon emissions in lb/day
V_{inst} = Air volume flowrate in standard cubic feet per day
TVP = True vapor pressure of hydrocarbons in lb/in^2 absolute

K. Emergency Portable and Stationary Engines

1. The emergency engines are limited to the hours of operation listed below, on a rolling 12-month time period:

ID No.	Emitting Unit ID	Description	Limited Hours	Rule Reference
SE1	HC/M601	Hydrocracker Backup Power Generator - Diesel	1,800 hr/yr	ARM 17.8.752
SE2	UT/P917B	Cooling Water Return to Alkylation Unit Water Screen (Fire Water) – Diesel	1,000 hr/yr	ARM 17.8.752
SE3	UT/P917A	Cooling Water Return to Alkylation Unit Water Screen (Fire Water) – Diesel	1,000 hr/yr	ARM 17.8.752
SE4	UT/P916	Pond 6 Water to Fire Mains - Diesel	1,000 hr/yr	ARM 17.8.752
SE5	CR/M201	Crude/Coker Backup Power Generator - Diesel	2,000 hr/yr	ARM 17.8.752
SE6	UT/C4	Boiler House Air Compressor -Diesel	2,000 hr/yr	ARM 17.8.752
SE7	UT/Port1	Boiler House Backup Air Compressor, Portable, Diesel-fired, not to exceed 500-hp	1,500 hr/yr	ARM 17.8.749
SE8	UT/Port2	Boiler House Backup Air Compressor, Portable, Diesel-fired, not to exceed 500-hp	1,500 hr/yr	ARM 17.8.749
SE9	EMES/Eng01	Site Remediation, Diesel-fired, not to exceed 250-hp	No limit on hours	ARM 17.8.749
SE10	EMES/Eng02	Site Remediation, Diesel-fired, not to exceed 250-hp	No limit on hours	ARM 17.8.749
SE11	EMES/Eng03	Site Remediation, Diesel-fired, not to exceed 250-hp	No limit on hours	ARM 17.8.749
SE12[*]	EMES/Eng04	Miscellaneous use, Diesel-fired, not to exceed 500-hp each	2,100,000 hp-hrs[**]	ARM 17.8.749
IEU06a	UT/P1A	Fire Water Pump at River Water Pump House -Gasoline	2,000 hr/yr	ARM 17.8.752
IEU06b	UT/P1B	Fire Water Pump at River Water Pump House -Gasoline	2,000 hr/yr	ARM 17.8.752

[*] SE12 is comprised of one or more engines that are collectively regulated as a single emitting unit.

[**] hp-hrs is determined by multiplying the maximum rated hp of an engine by its actual hours of operation. The sum of all the hp-hrs from the engines of SE12 are limited to 2,100,000 hp-hrs per rolling 12-month time period.

2. Engines SE7 through SE12 shall have an EPA certification of Tier 3 or higher (ARM 17.8.749).

3. ExxonMobil shall use only low-sulfur diesel fuel with a sulfur content less than or equal to 0.05% in SE1 through SE6 (ARM 17.8.752).

4. ExxonMobil shall use only ultra low-sulfur diesel fuel with a sulfur content less than or equal to 0.0015% in SE7 through SE12 (ARM 17.8.752).

5. ExxonMobil shall use gasoline with a sulfur content less than or equal to 0.1% in the gasoline-fired engines IEU06a and IEU06b (ARM 17.8.752).

L. Boiler (B-8)

1. SO_2 emissions from B-8 shall not exceed:

a. 3.40 tons per rolling 12-month period (ARM 17.8.749)

b. 0.78 lb/hr (ARM 17.8.749)

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

3. The NO_X emissions from B-8 shall not exceed:

   a. 0.04 lb/MMBtu based on a one-hour average, not applicable during start-up[1] and shutdown[1] (ARM 17.8.749 and ARM 17.8.752).

   b. 3.96 lb/hr based on a one-hour average (ARM 17.8.749)

   c. 17.3 tons per rolling 12-month period (ARM 17.8.749)

4. The CO emissions from B-8 shall not exceed:

   0.04 lb/MMBtu based on a one-hour average, not applicable during start-up[1] and shutdown[1] (ARM 17.8.749 and ARM 17.8.752).

   a. 3.96 lb/hr based on a one-hour average (ARM 17.8.749)

   b. 17.3 tons per rolling 12-month period (ARM 17.8.749)

5. ExxonMobil shall not cause or authorize to be discharged into the atmosphere from B-8, any visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

6. The heat input rate of B-8 shall not exceed 99.9 MMBtu-HHV/hr averaged over any rolling 24-hour period (ARM 17.8.749).

M. FCCU Wet Gas Compressor (C-310)

All applicable requirements of ARM 17.8.340, which reference 40 CFR 60, Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, shall apply to the C-310 compressor and any other equipment, as appropriate. A monitoring and maintenance program, as described under 40 CFR Part 60, Subpart VVa, shall be instituted (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart GGGa).

N. Monitoring

1. ExxonMobil shall install and operate the following CEMS/Continuous Opacity Monitoring System (COMS)/Continuous Emission Rate Monitor System (CERMS) at the FCC Unit CO Boiler Stack:

   a. Opacity (Consent Decree paragraph 43; ARM 17.8.340 and 40 CFR 60, Subpart J; ARM 17.8.342 and 40 CFR 63, Subpart UUU; and, 40 CFR Part 51, Appendix P);

[1] Start-up for B-8 is defined as the duration of time from the initial start of the unit to the point in time at which the firing rate exceeds 25% of the unit’s maximum capacity rating. Shutdown for B-8 is defined as the duration of time from the point at which the firing rate drops below 25% of the unit's maximum capacity rating to the point in time that fuel is no longer being combusted within the unit.

b. CO by no later than June 13, 2007 (ARM 17.8.749, Consent Decree Paragraph 42, ARM 17.8.340 and 40 CFR 60, Subpart J);

c. SO_2 by no later than June 13, 2007 (ARM 17.8.749, Consent Decree Paragraph 32, and SO_2 SIP); and

d. NO_x by no later than December 31, 2008 or as amended in the consent decree (ARM 17.8.749, Consent Decree Paragraph 21);

e. O_2 by no later than June 13, 2007 (Consent Decree paragraphs 21, 32 and 42); and

f. Volumetric Flow (SO_2 SIP).

2. CEMS/COMS/CERMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns and repairs (ARM 17.8.749).

3. Compliance and enforcement of the requirements on SO_2 emission rates and H_2S concentrations in Sections II.I.1, II.I.2, and II.I.3 shall be determined by utilizing data taken from CEMS and other Department-approved sampling methods (ARM 17.8.749, SO_2 SIP, and Consent Decree Paragraph 32).

4. In the event the primary SO_2 or H_2S CEMS are unable to meet minimum availability requirements, ExxonMobil shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated. The Department shall approve such contingency plans. SO_2 and H_2S CEMS shall be required to be maintained such that they are available and operating at least 90% of the source operating time during any reporting period (quarterly) (ARM 17.8.749 and SO_2 SIP).

5. All gaseous CEMS shall be required to comply with quality assurance/quality control procedures in 40 CFR 60, Appendix F (ARM 17.8.749).

6. ExxonMobil shall install, operate and maintain the applicable CEMS or develop an AMP as required by 40 CFR 60, Subpart J. Emission monitoring shall comply with all applicable provisions of 40 CFR 60.7 through 60.13; 40 CFR 60, Appendix A; Appendix B (Performance Specifications 1, 2, 3, 4, 6 and 7); and Appendix F (Quality Assurance/Quality Control) provisions.

7. Unless compliance with 40 CFR 60, Appendix F is otherwise required by the NSPS, state law or regulation, or a permit or SO_2 SIP, in lieu of the requirements of 40 CFR 60, Appendix F Sections 5.1.1, 5.1.3 and 5.1.4, during the life of the Consent Decree, ExxonMobil may conduct for the FCC CO Boiler CO CEMS: (1) either an CO Relative Accuracy Audit (“RAA”) or a Relative Accuracy Test Audit (RATA) once every 3 years; and (2) CO Cylinder Gas Audit (CGA) each calendar quarter in which a RAA or RATA is not performed (Consent Decree Paragraphs 21, 32, and 42).

8. Emissions (i) caused by or attributable to the startup, shutdown, or Malfunction of an FCC Unit and/or (ii) during periods of Malfunction of the relevant FCC Unit’s Control System(s) will not be used in determining compliance with the PM limits or short-term (7-day for NO_x, 7-day for SO_2, or 1-hour and/or 24-hour for CO) limits, provided that during such periods ExxonMobil implements good air pollution control practices to minimize said emissions. NO_x, SO_2, and CO emissions during any such period of startup, shutdown, or Malfunction shall either be: (i) monitored with CEMS; or (ii) monitored in accordance with an alternative monitoring plan approved by the Environmental Protection Agency (EPA) if it is necessary to bypass the FCC Unit’s main stack (Consent Decree Paragraph 20, 31, 36, and 41).

9. ExxonMobil shall comply with the applicable monitoring requirements contained in 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

10. ExxonMobil shall continuously monitor on the heat input rate into B-8 and provide averages on a rolling 24-hour basis. This information shall be used to verify compliance with the rolling 24-hour average limitation in Section II.L.6 (ARM 17.8.749).

O. Testing Requirements

1. ExxonMobil shall test furnace F-1201 on an every 5-year basis after the initial source test, or according to another testing/monitoring schedule as may be approved by the Department, to demonstrate compliance with the NO_X limitations for furnace F-1201 found in Section II.F.1 (ARM 17.8.106 and 17.8.749).

2. ExxonMobil shall test furnace F-551 on an every 5-year basis after the initial source test, or according to another testing/monitoring schedule as may be approved by the Department, to demonstrate compliance with the NO_X limitation for furnace F-551 found in Section II.H.1 (ARM 17.8.106 and 17.8.749).

3. Until the termination of the Consent Decree, ExxonMobil shall test the FCC Unit annually, or according to another testing/monitoring schedule as may be approved by the EPA, to demonstrate compliance with the PM limitation found in Section II.D.3.

4. ExxonMobil shall test the PMA Process Unit for Equipment leaks in accordance with 40 CFR 60, Subpart GGG (ARM 17.8.340 and 40 CFR 60, Subpart GGG).

5. In addition to the opacity CEMS required for the FCC Unit stack in Section II.P.1, opacity compliance may also be determined via EPA Reference Method 9 by a certified observer.

6. Compliance testing and continuous monitor certification shall be as specified in 40 CFR 60, Appendices A and B. Test methods and procedures, where there is more than one option for any given pollutant, shall be worked out with the Department prior to commencement of testing.

7. ExxonMobil shall conduct compliance testing and continuous monitor certification as specified in 40 CFR 60, Appendices A and B, within 180 days of initial startup of the affected facility.

8. Any stack testing that may be required shall be conducted according to 40 CFR 60, Appendix A and ARM 17.8.105, Testing Requirements provisions.

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

10. B-8 shall be tested initially within 180 days after commencing operation, and on an every 5-year basis thereafter, or according to another testing/monitoring schedule as may be approved by the Department, for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.L.3 and Section II.L.4 (ARM 17.8.105 and ARM 17.8.749).

11. ExxonMobil shall test the C-310 compressor for equipment leaks in accordance with 40 CFR 60, Subpart GGGa (ARM 17.8.340 and 40 CFR 60, Subpart GGGa).

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

P. Operational Reporting Requirements

1. ExxonMobil 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 most recent emission inventory report and sources identified in the 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 the actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. ExxonMobil shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

3. All records compiled in accordance with this permit must be maintained by ExxonMobil 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).

4. ExxonMobil shall document, by month, the total amount of RFG/natural gas consumed by furnace F-1201. By the 25th day of each month ExxonMobil shall calculate the total amount of RFG/natural gas consumed by furnace F-1201 during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.F.4. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.Q.1 (ARM 17.8.749).

5. ExxonMobil shall document by month, the average monthly percent of maximum firing rate, the monthly gas consumption (MMscf per month), the input fuel heat content (MMBtu/MMscf), and the monthly hours of operation of F-201 and F-5 for use in the following equations:

   $Y = m * (X/100) + b$

   Where:
   Y = Emission factor at a specific firing rate (lb/MMBtu)
   m = Slope factor (lb/MMBtu) / (% firing rate)
   X = % of maximum firing rate
   b = y-intercept (lb/MMBtu)

For F-201	For F-5
m = -0.0329	m = -0.1253
b = 0.141	b = 0.261

NO_X lb/hr = {(Y) * (gas consumption (MMscf/month)) * (fuel heat content (MMBtu/MMscf))} / (hours of operation per month (hr/month))
NO_X tons per month = {NO_X (lb/hr) * (hr/month)} / 2000 lb/ton

6. ExxonMobil shall document, by month, the amount of total NO_X emissions from F-201 and F-5. By the 25th day of each month ExxonMobil shall calculate the total amount of NO_X emissions from F-201 and F-5 during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.G.3. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.Q.1 (ARM 17.8.749).

7. ExxonMobil shall document, by month, the average concentration of H_2S (ppm) in the refinery fuel gas burned in F-201 and F-5. By the 25th day of each month ExxonMobil shall average the concentration of H_2S (ppm) in the refinery fuel gas burned in F-201 and F-5 during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.I.3. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.Q.1 (ARM 17.8.749).

8. ExxonMobil shall document, by month, the total fugitive VOC emissions from Tank 26. By the 25th day of each month ExxonMobil shall total the fugitive VOC emissions from Tank 26 during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.J. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.Q.1 (ARM 17.8.749).

9. ExxonMobil shall document, by month, the total VOC emissions from the PMA tanks (#72, #73, #76 & #77). By the 25th day of each month ExxonMobil shall calculate the total VOC emissions from these tanks during the previous month. ExxonMobil shall measure actual tank data (throughput and temperature) and use this data to calculate VOC emissions using EPA TANKS Version 4.0 software program. The monthly information shall be used to verify compliance with the rolling 12-month limitations in Section II.B.8 and II.B.10. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.Q.1 (ARM 17.8.749).

10. ExxonMobil shall document, by month, the total VOC emissions from the PMA loading operation. By the 25th day of each month ExxonMobil shall calculate the total VOC emissions from this operation during the previous month. ExxonMobil shall measure the actual monthly PMA throughput and monthly average temperature, and use this data in the petroleum liquid loading equation:

$L_L = 12.46\ SPM/T$ *(AP-42 Chapter 5.2)*

L_L = loading loss (lbs/1000 gallons of PMA loaded)
S = saturation factor (1.45)
P = true vapor pressure
M = molecular weight of vapors (105 lbs/lb-mole)
T = temperature of bulk liquids loading (deg R)

The monthly information shall be used to verify compliance with the rolling 12-month limitations in Section II.B.9 and II.B.10. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.Q.1 (ARM 17.8.749).

11. ExxonMobil shall sum the monthly VOC emissions from the PMA tanks and the PMA loading. The monthly information shall be used to verify compliance with the rolling 12-month limitation in Section II.B.10. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.Q.1 (ARM 17.8.749).

12. ExxonMobil shall document, monthly, the daily Tank #55 coalescer pressure drop readings and compare against the manufacturer's recommended range (ARM 17.8.340 and 40 CFR 60, Subpart UU).

13. ExxonMobil shall document by the 25th day of each month the number of operational hours since the previous month's documentation event for each of the engines listed in Section II.K.1. The monthly information shall be used to verify compliance with the rolling 12-month limitations in Section II.K.1. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.Q.1 (ARM 17.8.749).

14. ExxonMobil shall document, annually, the maximum sulfur content of the diesel and gasoline fuel used by the engines for the previous calendar year. Vendor specifications or certification that the fuels met the maximum sulfur content allowed by the current motor fuel regulations (40 CFR Part 80) will satisfy this requirement. The annual information shall be used to verify compliance with the limitations in Section II.K.3, 4, and 5. The information shall be submitted along with the annual emission inventory required by Section II.Q.1 (ARM 17.8.749 and ARM 17.8.752).

15. ExxonMobil shall provide quarterly emission reports from said emission rate monitors. Emission reporting for SO_2 from all point source locations shall consist of 24-hour calendar-day totals per quarter. The quarterly report shall also include the following:

    a. Source or unit operating times during the reporting period.

    b. Monitoring downtime that occurred during the reporting period.

    c. A summary of excess H_2S concentrations and/or SO_2 emissions and averaging period, for each new unit, as identified in Section II.I.

    d. Reasons for any emissions in excess of those specifically allowed in Section II.I, with mitigative measures utilized and corrective actions taken to prevent a recurrence of the upset situation.

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

16. ExxonMobil shall keep the Department apprised of the status of construction of the new and modified units, dates of performance tests, and continuous compliance status for each emission point and pollutant. Specifically, the following report and recordkeeping shall be required in writing:

    a. Notification of initial emission tests and monitor certification tests.

b. Submittal for review by the Department of the emission testing plan, results of initial compliance tests, continuous emission monitor certification tests, continuous emission monitoring and continuous emission monitoring quality assurance/quality control plans, and excess emissions report format within the 180-day shakedown period.

c. Copies of quarterly emission reports, H_2S and SO_2 monitoring data, excess emissions, and all other such items mentioned in Section II.Q.16.a and b, above, shall be submitted to both the Billings regional office and the Helena office of the Department.

d. Monitoring data shall be maintained for a minimum of 5 years at the Billings ExxonMobil Refinery.

e. All data and records that are required to be maintained must be made available, upon request, to representatives of the Department and the U.S. Environmental Protection Agency.

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

18. Based on the monitoring required in Section II.O.10, ExxonMobil shall document any exceedance of the rolling 24-hour average limitation specified in Section II.L.6. Any exceedance shall be reported and submitted with the quarterly emission report required in Section II.Q.15 (ARM 17.8.749).

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

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

21. Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by the Department (ARM 17.8.340 and ARM 17.8.749).

Q. Notification

1. ExxonMobil shall notify the Department within 30 days after the new B-8 boiler is capable of combusting refinery fuel gas for NSPS Ja applicability (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60, Subpart Ja).

2. ExxonMobil shall notify the Department within 30 days after the commencement of operation of any new or replacement engine for units SE1-SE11 and IEU06a and IEU06b as described in Section II.K.1 (ARM 17.8.749).

Section III. General Conditions

A. Inspection – ExxonMobil shall allow the Department’s representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

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

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving ExxonMobil 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, as amended by the 1991 Legislature, failure to pay the annual operation fee by ExxonMobil may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

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

Montana Air Quality Permit (MAQP) Analysis
Exxon Mobil Corporation – Billings Refinery
MAQP #1564-26

I. Introduction/Process Description

A. Site Location

The Exxon Mobil Corporation – Billings Refinery (ExxonMobil) is located in the S½ of Section 24 and the N½ of Section 25, Township 1 North, Range 26 East, Yellowstone County, Montana. The bulk-marketing terminal is located adjacent to the refinery and operates under a separate preconstruction permit.

B. Existing Source Description

This permit provides external emission offsets from the ExxonMobil refinery for the issuance of a permit for an adjacent facility owned and operated by Yellowstone Energy Limited Partnership (YELP) (Montana Air Quality Permit (MAQP) #2650-01, dated February 14, 1992, and subsequent permits). These offsets are provided by the following requirements contained in this permit: required delivery of all coker process gas stream to YELP any time YELP is operating (Section II, Part A); an hourly limitation on sulfur-in-fuel burned at the refinery (Section II, Part B); and a daily limit on the number of barrels of fuel oil that may be burned at the refinery (Section II, Part C). In addition, to ensure these offsets are enforceable and to protect the integrity of the National Ambient Air Quality Standards (NAAQS) for sulfur dioxide (SO_2), ExxonMobil is required to provide notice to YELP in the event that it fails to comply with the requirements contained herein concerning either the hourly sulfur-in-fuel limitation (Section II, Part B) or the daily fuel oil firing limit (Section II, Part C). These requirements do not apply when YELP is not operating its facility, since emission offsets are not required (MAQP #1564-03).

This permit includes, but is not limited to, the following equipment:

1. One coke producing coker facility with an associated carbon monoxide (CO) boiler capable of producing steam for use in the general facility.

2. One CO boiler (Coker CO Boiler).

3. All refinery fuel oil and fuel gas-consuming combustion units (i.e., boilers, furnaces, etc.).

4. An 800-ton per day Polymer Modified Asphalt (PMA) unit (928-ton per day including asphalt storage), which includes the following equipment (MAQP #1564-04, modified to improve efficiency in MAQP #1564-17):

    a. Four PMA storage tanks, with external heat exchangers installed to replace internal steam coils (MAQP #1564-17):

        - Tanks #72 & #73 – 973,000 gallons each (approx. 23,000 barrels)

        - Tanks #76 & #77 – 207,000 gallons each (approx. 5,000 barrels)

    b. One 1966 circulation pump (P-58)

c. One fixed roof wetting/mixing tank (Tank # 960, approx. 265 gallons)

d. One high sheer mill feed pump (ratio pump)

e. One high sheer mill (centrifugal pump) (MAQP #1564-17)

f. Additive injection equipment

g. One sales dispensing pump (P-1A)

h. One PMA service pump

i. One 1948 truck loadout (west rack)

j. Railcar loading for PMA (spots #1, #3 & #5)

k. Various valves and flanges

5. One D-4 drum atmospheric vent stack extension, from 40.8 to 70.1 meters, with added steam injection capability to raise the equivalent height of the stack to 79.2 meters (MAQP #1564-05).

6. One Fluidized Catalytic Cracker (FCC)/CO Boiler stack extension.

7. Tank 26 (Change in the method of operation as part of MAQP #1564-09).

8. Furnace F-1201 (Installed under MAQP #1564-09).

9. Hydrofiner #1 (Modified to produce and segregate Ultralow Sulfur Diesel (ULSD) Products in MAQP #1564-14 and 15).

10. Hydrofiner #3 (Modified to produce and segregate ULSD Products in MAQP #1564-14 and 15).

11. Furnace F-551 (Modified to increase capacity in MAQP #1564-16).

12. Emergency Stationary Engines (Permitted under MAQP #1564-18):

ID No.	**Emitting Unit ID**	**Description**	**Year in Service**	**Fuel**	**Max Horsepower (hp)**
SE1	HC/M601	Hydrocracker Backup Power Generator	1986	Diesel	210
SE2	UT/P917B	Cooling Water Return to Alkylation Unit Water Screen (Fire Water)	1998	Diesel	370
SE3	UT/P917A	Cooling Water Return to Alkylation Unit Water Screen (Fire Water)	1998	Diesel	370
SE4	UT/P916	Pond 6 Water to Fire Mains	1991	Diesel	370
SE5	CR/M201	Crude/Coker Backup Power Generator	2002	Diesel	66
SE6	UT/C4	Boiler House Air Compressor	2006	Diesel	475
IEU06	UT/P1A	Fire Water Pump at River Water Pump House	1950	Gasoline	230
IEU06	UT/P1B	Fire Water Pump at River Water Pump House	1950	Gasoline	230

13. Portable Emergency, Remediation, and Miscellaneous Activity Engines which shall have an EPA certification of Tier 3 or higher (Permitted under MAQP #1564-24):

ID No.	**Emitting Unit ID**	**Description**	**Year in Service**	**Fuel**	**Max Horsepower (hp)**
SE7	UT/Port1	Boiler House Backup Air Compressor	2011	Diesel	500
SE8	UT/Port2	Boiler House Backup Air Compressor	2011	Diesel	500
SE9	EMES/Eng01	Site Remediation	2011	Diesel	250
SE10	EMES/Eng02	Site Remediation	2011	Diesel	250
SE11	EMES/Eng03	Site Remediation	2011	Diesel	250
SE12*	EMES/Eng04	Miscellaneous Activities	2011	Diesel	500-hp each and 2,100,000 hp-hrs total**

* SE12 is comprised of one or more engines that are collectively regulated as a single emitting unit.

** hp-hrs is determined by multiplying the maximum rated hp of an engine by its actual hours of operation. The sum of all the hp-hrs from the engines of SE12 are limited to 2,100,000 hp-hrs per rolling 12-month time period.

14. Natural gas-fired residential furnace rated at 10 standard cubic feet per minute used to heat the Operator's Shelter (MAQP #1564-20).

C. Process Description

The ExxonMobil refinery converts crude oil into various refined products including refinery fuel gas (RFG), liquefied petroleum gas (LPG), aviation fuels, unleaded gasoline, jet fuels, kerosene, diesels, heavy fuel oil, asphalts, and fluid petroleum coke. The following is a brief summary of the petroleum refining process at the ExxonMobil facility.

Crude oil is generally a mixture of paraffinic, naphtheic, and aromatic hydrocarbons with some impurities including sulfur, nitrogen, oxygen, and metals. Refining at ExxonMobil begins by physically separating the crude oil constituents into common-boiling-point fractions using three separation processes: atmospheric distillation, vacuum distillation, and light ends recovery. Through various means, residual oils, fuel oils and light ends are converted to gasolines, jet fuels, and diesel fuels; heavier ends are converted to asphalt and coke.

Cracking and coking split large petroleum molecules into smaller ones. The alkylation processes use a catalyst to react small petroleum molecules together to make larger ones. The reforming process rearranges the structure of petroleum molecules to produce higher-octane value molecules of a similar molecule size. Using this conversion process, low-octane naphtha can be converted into high-octane gasoline.

Fuel gas streams containing hydrogen sulfide (H_2S) are typically sent to Montana Sulphur and Chemical Company (MSCC), where they are treated in an amine treatment unit that separates the H_2S from the cleaned fuel gas. The clean fuel is returned to the refinery where it is used in the refinery process heaters and boilers.

D. Permit History

The Billings Exxon Refinery requested a modification to **MAQP #1564A2** to support the YELP permit. The permit modification was given **MAQP #1564-03**. That request was addressed under the provisions of Subchapter 7, Administrative Rules of Montana (ARM) 17.8.733(l)(b). Exxon proposed to do the following in conjunction with the YELP permit: (1) send all coker process gases to YELP for treatment; (2) change the manner in which the refinery-wide sulfur-in-fuel emission limitation is calculated (daily to hourly) for all fuel-burning units; (3) change the 1.1 pounds per million British thermal units (lb/MMBtu) sulfur limit to 0.96 lb/MMBtu in order to provide sufficient offsets for the YELP facility; (4) cap the refinery fuel oil burning at 720 barrels per day any time YELP is operating both of its boilers; (5) provide additional verification of SO_2 emission reduction by the addition of recording devices on the Coker CO Boiler (KCOB) fuel oil-firing unit and storage fuel oil system, and by utilizing the present emission calculation/accounting procedures at the refinery.

The projected operational changes in Exxon's general Operating MAQP (#1564A) would reduce SO_2 emissions into the Billings airshed. This reduction takes place as a result of the coker process gas emissions, which include SO_2, CO, coke fines, reduced sulfur compounds and nitrogen oxides (NO_X) being sent to YELP for treatment. This is discussed further in the YELP Permit Analysis.

In addition, Exxon proposed no fuel oil burning in the KCOB any time YELP is operating two boilers, plus a commitment to adhere to an hourly sulfur-in-fuel limitation on a refinery-wide basis when YELP is operating both of their boilers.

Adherence to an hourly sulfur-in-fuel limitation was changed from 1.1 to 0.96 lb of sulfur in fuel per million Btu fired. This change was equated to a 100-ton per year offset based on actual SO_2 emissions for the past 2 years. In addition, Exxon committed to a daily refinery fuel oil consumption cap of 720 barrels any time YELP is operating two boilers. This condition was insisted upon by the U.S. Environmental Protection Agency (EPA) because of the difficulty in meeting the federal definition of federally enforceable emission limits. Logic suggested that if the YELP facility was to operate as expected and provided the anticipated steam load to Exxon, a larger reduction in SO_2 emissions would actually be realized because of reduced fuel oil firing at the refinery.

It would be critical for both parties, YELP and Exxon, to coordinate their activities closely once operation of YELP had commenced. The Exxon proposal was based on the attached information and more fully explained the 100-ton per year figure and also the rationale for the block hourly 0.96 lb of sulfur-in-fuel figure calculated on a refinery-wide basis.

Exxon had requested that the Montana Department of Environmental Quality (Department) consider revision of their permit when the new 213-foot stack at MSCC was constructed and made federally enforceable. This increase in stack height lessened MSCC's impact and could have decreased the required offset at Exxon for YELP. The Department agreed to provide the opportunity for such a revision. However, before Exxon's sulfur-in-fuel limit could be increased, the new 213-foot stack had to be made federally enforceable through a modification of MSCC's Air Quality Permit. Further, the Department believed the increased stack height may have been necessary to address concerns with the current State Implementation Plan (SIP) and, therefore, may not have been available to reduce the required emission offset at Exxon.

On November 12, 1994, Exxon was issued **MAQP #1564-04** to construct and operate an 800-ton per day PMA unit. The PMA unit would allow Exxon to produce polymerized asphalt.

Conventional asphalt base stock is mixed with solid polymer pellets in a wetting/mixing tank, ground with a sheer mill, and returned to the PMA storage tank. The PMA is then loaded out through existing stubs at the west rack. No additional steam demand or fuel consumption was necessary for the PMA project. Volatile Organic Compound (VOC) emissions were the primary pollutants of concern; however, all VOC emissions from equipment and tanks in asphalt service were assumed to be negligible since asphalt has negligible vapor pressure at the working temperature seen in the unit.

This alteration also addressed Exxon's August 9, 1994, modification request to replace the strip recorder of the tank gauging device on the fuel oil storage system with a data transmission system inputting to a data acquisition system (DAS). This modification would allow Exxon to use the computer system to collect and archive the fuel data to meet permit conditions.

On August 25, 1995, Exxon was issued **MAQP #1564-05** for a stack extension to the D-4 drum atmospheric vent stack constructed in July 1993. The stack extension raised the height of the D-4 drum atmospheric vent stack from 40.8 meters (134 feet) to 70.1 meters (230 feet). In addition, steam injection capability was added to raise the effective height of the stack to 79.2 meters. The stack extension was designed to eliminate refinery worker exposure impacts during emergencies.

The D-4 atmospheric vent drum was a safety device used to control and manage both routine and abnormal releases from process units. A limited number of safety valves and intermittent blowdowns from the crude, hydrofiner and coker units were vented to this drum. Inside the drum, a continuous flow of water cooled any safety valve releases or blowdowns to condense vapors for subsequent treatment in the wastewater treatment plant. Any vapors not condensed exited through the D-4 drum atmospheric vent stack.

On January 14, 1996, Exxon was issued **MAQP #1564-06** to construct the FCC/CO Boiler stack extension from 63.4 to 76.7 meters and the F-2 Crude/Vacuum Heater stack from 63.6 to 65 meters. As part of the 1995 proposed Billings/Laurel SO_2 SIP, Exxon and the Department stipulated that Exxon shall extend the heights of the F-2 Crude/Vacuum Heater and FCC/CO Boiler stacks to at least 65 meters. Exxon was allowed to raise these stacks to above 65 meters, but received a Good Engineering Practices (GEP) credit for modeling purposes of 65 meters. Exxon would be entitled to a greater GEP credit for either stack if a physical demonstration (fluid model or field study) was conducted and justified a taller GEP stack height.

On June 17, 1996, the Department issued **MAQP #1564-07** to modify the opacity limitations for the wetting/mixing tank exhaust vent in the PMA unit. The requirements of 40 CFR 60, Standards of Performance for New Stationary Sources (NSPS), Subpart UU – Standards of Performance for Asphalt processing and Asphalt Roofing Manufacture, were reviewed during the initial permit review and it was determined that this subpart was not applicable to the wetting/mixing tank because the tank was used for mixing only and did not store asphalt; therefore, it did not meet the definition of a storage tank. The opacity limit set in the original permit, however, was representative of an asphalt tank that was used for storage of asphalt as defined under

NSPS, Subpart UU. The permitted opacity limit did not recognize the fact that mixing asphalt is occurring in the mixing tank. Due to mixing, there may have been a noticeable opacity at the wetting/mixing tank top, even when mixing temperatures were well below 400° F.

A 20% opacity limit was set to reflect the effects of minor mixing in the wetting/mixing tank, which was consistent with ARM 17.8.304 (2). This rule required that no person may cause or authorize emissions to be discharged to an outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

Exxon would still need to maintain the operating temperature of the wetting/mixing tank below the smoking point of asphalt in order to comply with the 20% opacity limit. The wetting/mixing tank only operates intermittently during the summer asphalt season. Any opacity is localized inside the refinery and does not create a public nuisance.

On April 9, 1999, the Department received a request to modify Exxon's MAQP #1564-07 to bring the permit closer to the requirements of the June 12, 1998, stipulation between Exxon, the Department, and the Board of Environmental Review (Board). The changes reduced the reporting and recordkeeping burden for both Exxon and the Department, updated the permit with current rule references, and consolidated all the previously issued permits to Exxon in **MAQP #1564-08**.

Exxon also holds a permit for the bulk marketing distribution terminal located adjacent to the refinery. Although the refinery and bulk terminal hold separate preconstruction permits, for any Prevention of Significant Deterioration (PSD) permitting action, the refinery and bulk terminal are considered one facility and must be evaluated as such for any emission increases or decreases.

MAQP #1564-08 replaced MAQP #1564-07 and all permits identified in Table I.2 of MAQP #1564-08.

On July 1, 1997, Exxon applied via MAQP Application #1564-08a to construct a sulfur processing facility to be located at the Billings refinery. Exxon was the applicant, with TRC Consultants performing the Best Available Control Technology (BACT)/regulatory analysis and the modeling impact analysis. The Department requested additional permitting information and clarification on July 31, 1997. Formal responses to the original deficiencies were received on September 4, 1997, and a confidential package, protected under court order, was received on October 2, 1997. Exxon transfers via pipeline, sour fuel gas and acid gas (H_2S) to the MSCC facility located adjacent to the refinery. The proposed sulfur processing facility would have eliminated the need to send the gases off site and would have enabled Exxon to treat the sour fuel gas and acid gas streams and produce sulfur as a marketable product.

On October 7, 1997, the Department was informed that Exxon had signed a multi-year contract with MSCC and the project was on hold. On October 16, 1997, Exxon requested a meeting with the Department to formally withdraw the permit application and request that all materials submitted in support of the application be returned to Exxon. The material was to include all volumes of the application submittals and the package of confidential business information submitted on October 2, 1997. On October 22, 1997, the Department sent a letter to acknowledge the official withdrawal of Application #1564-08a and to inform Exxon that the materials submitted in support of the application would not be returned to Exxon. The Department's legal staff had confirmed that the public record must be preserved and the materials could not be returned to the applicant.

On August 21, 2000, Exxon submitted a permit application to the Department, with additional submittals on November 13, 2000, and November 22, 2000. The submittals requested the following changes to MAQP #1564-08:

1. Addition of one new furnace (F-1201) with a firing capacity of 99 MMBtu/hr or less;

2. Allowance for the modification of furnace F-700 to increase its firing capability from 105.6 MMBtu/hr to 122 MMBtu/hr; and

3. Modification to the method of operation of Tank 26 to reduce volatilization of the stored petroleum product.

4. A name change from Exxon Company U.S.A. to Exxon Mobil Corporation (received January 7, 2000).

5. Clarification of new operating temperature used in Section II.E.1. The description of the operating temperature was changed from "minimum operating temperature" to "operating temperature of the wetting/mixing tank below the smoking point of asphalt."

6. Attachment of the letter dated September 25, 1989, which specifies the monitoring procedures (Appendix A) to be used for the permit (the above letter was previously referenced for monitoring procedures).

The requirements contained in Section II, Parts B and C, concerning an hourly limitation on sulfur in fuel and a daily limitation on fuel oil firing, respectively, apply on a refinery-wide basis to all fuel-burning units at the refinery, consistent with the 1977 Stipulation. **MAQP #1564-09** reflected all of the above changes and replaced MAQP #1564-08.

MAQP #1564-10 was not issued. Two applications were received within the same time period to alter MAQP #1564-09 and were not issued in the order in which they were received. To avoid confusion in referencing these permit applications and actions, MAQP #1564-10 was removed from use.

On March 3, 2001, the Department issued a permit for the installation and operation of two temporary aero-derivative jet engine electricity generators (Model LM1500), each capable of generating approximately 10 megawatts of power, and an accompanying diesel storage tank. These generators were necessary because of the high cost of electricity. The operation of the generators would not occur beyond 2 years and was not expected to last for an extended period of time, but rather only for the length of time necessary for ExxonMobil to acquire a more economical supply of power.

Because these generators would only be used when commercial power was too expensive to obtain, the amount of emissions expected during the actual operation of these generators was minor. In addition, the installation of these generators qualified as a "temporary source" under the PSD permitting program because the permit limited the operation of these generators to a time period of less than 2 years. Therefore, ExxonMobil was not required to comply with ARM 17.8.804, 17.8.820, 17.8.822, and

17.8.824. Even though the portable generators were considered temporary, the Department required compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 was ensured. In addition, ExxonMobil was responsible for complying with all applicable air quality standards. **MAQP #1564-11** replaced MAQP #1564-09.

On May 16, 2001, the Department issued a permit for the installation and operation of a temporary aero-derivative jet engine electricity generator (Model LM1500), capable of generating approximately 10 megawatts of power. This generator would be used in addition to the two similar generators permitted in #1564-11 and would be considered a part of the same project with respect to time constraints. This generator and the two generators previously permitted are necessary because of the high cost of electricity. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for ExxonMobil to acquire a more economical supply of power.

As previously mentioned, because the generators will only be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of the generators is minor. In addition, the installation of the generators qualifies as a "temporary source" under the PSD permitting program because the permit will limit the operation of the generators to a time period of less than 2 years. Therefore, ExxonMobil will not need to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, the Department requires compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 will be ensured. In addition, ExxonMobil is responsible for complying with all applicable air quality standards. **MAQP #1564-12** replaced MAQP #1564-11.

On February 13, 2002, the Department received a permit application to address emission increases associated with the modifications that allowed approximately 500 barrels per day more fresh feed to be processed through the Fluid Coker unit (Coker). Other units/processes that were affected by the proposed modifications included the fluidized catalytic cracking unit (FCCU), the motor gasoline (mogas) storage tank throughputs, and the refinery fuel gas system throughput. Included in this permitting action was a limit on refinery-wide fuel oil combustion used to keep the overall SO_2 emissions increase from the project below PSD SO_2 significance levels. In addition, a contemporaneous decrease in VOC emissions on Tank #309 offset the increase in VOC emissions from the project, to keep the project below PSD VOC significance levels.

The project involved the following activities (not all of them requiring permitting, but all included in the application as they relate to the overall project):

1. Replace the existing product coke line with a larger diameter pipe and remove a number of bends and turns to decrease piping pressure drop. Line size increased from 6 inch to 8 inch in diameter and allowed for a product coke capacity of approximately 550 tons per day. This line connects from the Coker unit to the BGI coke silo (capacity related);

2. Upgraded the gearbox of the Coker light ends compressor to facilitate compressing the increased volume of light ends from the higher throughput at the Coker. This compressor (C-311) is located in the refinery Gas Compressor Building near the north end of the FCCU facility (capacity related);

3. Installed new steam aeration nozzles and replaced appropriate sections of the scouring coke line from the Coker burner to the reactor. This allowed improved coke circulation and allowed ExxonMobil to avoid excessive coke buildup at the Coker area (maintenance related);

4. Installed a multi-hole orifice chamber in the Coker Process Gas line that goes to either BGI or the Coker CO Boiler. This device stabilized the back-pressure that the slide valves, located on the top of the Coker burner vessel, have to control. This device allowed smoother transition in unit operations whenever the Coker Process Gas must be diverted away from BGI and back to the Coker CO Boiler (maintenance and capacity related);

5. Modified the cyclone outlet from the Coker reactor to the scrubber section to a newer design, which has a custom designed elbow and larger horn (outlet), decreasing the velocity and pressure drop through the cycle to accommodate an increased vapor rate. The cyclone is located at the top of the Coker reactor outlet and carries reactor hydrocarbon vapors into the scrubber section of the vessel (capacity related);

6. Modified the internals of the D-202 Coker Fractionator Overhead receiver drum to improve liquid/vapor separation. This drum is located at the Coker unit (capacity related);

7. Modified the Coker reactor feed pumps and drivers to increase capacity to match the 500 barrel per day unit increase and higher discharge pressure requirements. The reactor feed pumps take oil from the scrubber and recycle this liquid back to the feed surge drum and supply the reactor feed nozzles. By increasing the speed of the pump impellers, both pressure and increased capacity requirements are satisfied without having to replace the pumps. The bearing housings would be upgraded, if necessary, to safely achieve these higher speeds (capacity related);

8. Modified the reactor feed nozzle system with an improved design. The intent of these changes was to optimize the Coker unit feed nozzle system operation (capacity related); and

9. Included adequate safety facilities to address safety concerns at the higher Coker unit capacity. This may have included replacement of some vessel nozzles and connecting piping to upgrade metallurgy or refractory linings such that higher operating temperatures could be achieved. This may have also included the installation of larger safety valves and associated piping (capacity related).

MAQP #1564-13 replaced MAQP #1564-12.

On October 22, 2003, the Department received an MAQP Application from ExxonMobil to modify MAQP #1564-13 to meet the EPA 15 parts per million (ppm) sulfur standard for highway diesel fuel. On December 4, 2003, the Department deemed the application complete. Units/processes that were affected by the proposed modifications included the Kerosene Hydrofiner (Hydrofiner No. 3), Diesel Hydrofiner (Hydrofiner No. 1), new facilities to segregate Hydrocracker diesel from Hydrofiner No. 1 diesel, and modifications and additions to facilities to segregate highway and off-road No. 2 diesel fuels. The modifications resulted in an increase in throughput through the FCCU and an increase on motor gas (mogas) production. This permitting action resulted in a limit on refinery-wide fuel oil combustion so that the overall SO_2 emissions increase from the project would stay below the PSD SO_2 significance levels. The permit action took out all references to the temporary generators that were previously permitted and were removed from the facility. The equation for Tank 26 was updated to more accurately account for temperature and pressure in the calculation of VOC emissions for Tank 26. **MAQP** #**1564-14** replaced MAQP #1564-13.

On April 9, 2004, the Department received a MAQP Application from ExxonMobil to modify MAQP #1564-14 for changes in how ExxonMobil planned to meet the EPA's 15 ppm sulfur standard for highway diesel fuel. Units/processes affected by the proposed modifications included the addition of a lubricity facility and the addition of minor piping. ExxonMobil no longer planned to segregate Hydrocracker diesel from Hydrofiner No. 1 diesel, or to segregate highway and off-road No. 2 diesel fuels. The current modification resulted in an increase in throughput through the FCCU, an increase in mogas production, an increase at the Hydrogen Unit, and an increase in throughput at the marketing terminal. The permitting action resulted in a limit on refinery-wide fuel oil combustion so that the overall SO_2 and particulate matter (PM) emissions increase from the project would stay below the PSD SO_2 and PM significance levels. **MAQP #1564-15** replaced MAQP #1564-14.

On February 9, 2005, the Department received a complete MAQP Application from ExxonMobil to modify MAQP #1564-15. The purpose of the application was to address the replacement of six existing convection section tubes with six new finned convection section tubes in the Steam Reforming Furnace (F-551) located in the Hydrogen Plant. Replacing and finning the upper tube row in the secondary preheat coil of F-551 allowed for improved heat absorption from the process stream which in turn results in improved Hydrogen Plant production. The modifications directly affected F-551 and, potentially, indirectly increased throughput to the FCCU, Alkylation Unit, Powerformer Unit, and Hydrocracker Unit. Crude oil throughput did not increase as a result of the modification. The permitting action resulted in lowering the existing limit on refinery-wide fuel oil combustion so that the overall SO_2 and PM emissions increase from the project was be below the PSD SO_2 and PM significance levels. Section II.F.2 of the Permit Analysis (MAQP #1564-16) included a discussion of the netting analysis conducted for the permit action. **MAQP #1564-16** replaced MAQP #1564-15.

On September 22, 2005, the Department received a complete MAQP Application from ExxonMobil to modify MAQP #1564-16. Further information was received in a letter from ExxonMobil dated October 20, 2005. The purpose of this application was to address several projects impacting the PMA unit. ExxonMobil proposed modifications to the PMA process unit and addition of a new PMA railcar loading in order to create more PMA from a historical production rate of 300 – 600 barrels/day, to 5000 barrels/day PMA, and to allow PMA loading of railcars. In addition, on October 19, 2005, the Department received a request for an Administrative Amendment to allow the use of Method ASTM D1298 for determining the API gravity of fuel oil. These permit actions were combined**. MAQP #1564-17** replaced MAQP #1564-16.

On October 5, 2005, the Department received a MAQP Application from ExxonMobil to incorporate the following emergency stationary engines into MAQP #1564-17: five existing diesel-fired engines; one new diesel-fired engine; and two existing gasoline-fired engines. After receiving additional submittals from ExxonMobil, the Department determined that the application was complete on February 17, 2006. **MAQP** #**1564-18** replaced MAQP #1564-17.

The Department received the following two de minimis notifications and two administrative amendment requests from ExxonMobil:

- 12/22/05 – CHUB-Amine and Fluidized Catalytic Cracking (FCC) Unit de minimis notification (no permit changes required).

- 1/11/06 – Administrative Amendment request to eliminate fuel oil monitoring requirements, based on elimination of fuel oil firing at the refinery;

- 4/5/06 – Administrative Amendment request to incorporate Consent Decree requirements; and

- 2/9/07 – De minimis notification for addition of Selective Catalytic Reduction (SCR) to FCC Unit Carbon Monoxide (CO) boiler and treat Sour Water Stripper (SWS) overhead to meet Consent Decree requirements (no permit changes required).

In addition to modifying the permit as necessary per the aforementioned de minimis notifications and administrative amendment requests, Section II of the permit was also reorganized and extraneous permit conditions were eliminated. **MAQP #1564-19** replaced MAQP #1564-18.

On February 28, 2008, a de minimis notification was received proposing process modifications in order to achieve emission reductions mandated by the US EPA Consent Decree (CD). The notification proposed the following process modifications:

1. Nitrogen Oxide (NO_x) control – proposal to install a third catalyst bed to the Selective Catalytic Reduction (SCR) unit on the FCCU Carbon Monoxide Boiler (COB) in order to meet the requirements of ExxonMobil's CD, Paragraph 17a. This proposal supersedes the May 8, 2006 notification for installation of a Thermal DeNO_x system and Ultralow NO_x Burners, and is a modification and update of the February 9, 2007, notification for the installation of the SCR on the FCCU and FCCU COB.

2. Proposal to remove the five existing soot blowers and replace with 17 new soot blowers to assist with boiler tube fouling and increased temperatures in the boiler.

3. Proposal to replace air blowers for FCCU COB to help maintain current boiler capabilities at increased operating pressure.

4. SO_2 control – proposal to treat the Sour Water Stripper (T-23) overhead gas (SWS Overhead Project) with hydrogen peroxide treatment, in order to meet Subpart A and J requirements as mandated by the CD paragraph 59. This supersedes the February 9, 2007, proposal to treat the SWS overhead gas with caustic wash treatment.

On April 15, 2008, a de minimis notification was received proposing the following process modifications mandated by the US EPA CD that requires ExxonMobil to comply with the NSPS, 40 CFR 60, Subparts A and J for the main flare and turnaround flare:

1. Flare Gas Recovery (FGR) Unit – modifications to existing FGR unit, including a proposal to install a two-stage dry helical screw compressor to pressurize the flare gas and to allow gas to be sent to MSCC.

2. Sweet Fuel Gas Letdown Facilities – proposal to add a sweet fuel gas letdown line with associated knock out (KO) drum to allow flaring of the sweet fuel gas in the event that MSCC is shut down.

3. Connection between J-901 and C-311 – proposal to use the J-901 Flare Gas Eductor to recover flare gas into C-310 FCC Wet Gas Compressor in the event that the FGR unit is shut down. In addition, ExxonMobil proposed to add new piping to recover flare gas from J-901 into C-311 Coker Gas Compressor if both the FGR unit and the FCCU are shutdown.

4. H_2S continuous emission monitoring system (CEMS) – proposal to add a CEMS to the flare header to monitor H_2S concentration of the gas sent to either the turnaround flare or the main flare.

5. Unsaturated Light Ends (ULEB) Unit – modification to ULEB unit to mitigate potential flaring events, including: replacement of safety valves on the Unsaturated Caustic Prewash Drum D-326 and Unsaturated Caustic Settling Drum D-327; addition of a sleeve/dipleg added to D-327, and the addition of high pressure alarms on the two DEA regenerator towers (T-305 and T-607).

6. Modification to D-942 Seal Drum – modify or replace the existing sparger in the D-942 Seal drum to increase the existing 12-inch glycol seal to between 18 and 24 inches.

On June 19, 2008, a de minimis notification was received for operation of a natural gas furnace in a new Operation and Control Center Building. The natural-gas fired residential furnace is rated at 10 standard cubic feet per minute (scfm) resulting in potential emissions significantly less than 15 tons per year (TPY).

On November 24, 2008, an Administrative Amendment request was received proposing inclusion of language in the permit signifying modified or the potential to modify CD deadlines as negotiated by ExxonMobil. **MAQP #1564-20** replaced MAQP #1564-19.

On July 6, 2009, (with additional information received on August 11, 2009), the Department received a request from ExxonMobil to modify MAQP #1564-20 to reflect decommissioning of the existing B-8 boiler, construction and operation of a temporary natural gas-fired boiler for a period of up to twelve months, and construction of a new permanent B-8 natural gas and/or refinery fuel gas-fired boiler.

The decommissioning of the existing B-8 boiler is part of a NOx reduction strategy as required by the US EPA Consent Decree (United States et al. v. Exxon Mobil Corporation et al., dated December 13, 2005).

In addition to making the requested change, the Department 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 following a federal court vacature. **MAQP #1564-21** replaced MAQP #1564-20.

On December 18, 2009, the Department received a request from ExxonMobil to administratively amend their current permit to clarify permit conditions contained in MAQP #1564-21, specifically pertaining to a temporary B-8 boiler (B-8 Temp). Inadvertently, a portion of the conditions identified in MAQP #1564-21 for B-8 Temp were incorrectly stated. Specifically, these conditions pertain to operational time frames of B-8 Temp and also the existing B-8 boiler. The changes were incorporated into **MAQP #1564-22.**

On December 24, 2009, the Department received an Application for an Air Quality Permit Modification from ExxonMobil to incorporate modifications to MAQP #1564-21. The requested changes included the addition of new fugitive volatile organic compound (VOC) components and a modification to compressor C-310. Because of the uncertainty associated with the current Montana de minimis rule (ARM 17.8.745) with respect to the rule having not yet been approved by EPA into Montana's State Implementation Plan (SIP) and the need to comply with internal company policy, ExxonMobil chose to group future VOC fugitive component additions and apply for a permit modification on that basis instead of using ARM 17.8.745 when such components were added in smaller increments and associated with separate projects.

In order to meet requirements outlined within the EPA Consent Decree (CD) (United States et al. v. Exxon Mobil Corporation *et al*., dated December 13, 2005), ExxonMobil intends to install a larger second eductor (J-902) for flare gas management. The gas to operate J-902 will come from C-310. The increase of flare gas recovery associated with J-902 will result in a decrease of C-310 gas compression from the fluidized catalytic cracking unit (FCCU), which in turn will decrease FCCU capacity. In order to recover this lost FCCU capacity, the proposed project was to install a new, larger C-310. In April 2009, a de minimis request was approved for a modification to this unit. ExxonMobil had changed the scope of the project to install a new unit. **MAQP #1564-22** replaced MAQP #1564-21.

On May 17, 2010, the Department received a request from ExxonMobil to administratively amend their current permit to include applicable requirements contained in paragraphs 70, 71, and 73 of the United States Environmental Protection Agency (USEPA) Consent Decree (CD) (United States *et al*. v. Exxon Mobil Corporation et al., dated December 13, 2005) and the amendments to the CD filed on January 26, 2009. Paragraph 145 of the CD requires permit limits outlined within paragraphs 70, 71, and 73 to survive the termination of the CD. This permit action incorporated these specific limits. **MAQP #1564-23** replaced MAQP #1564-22.

On April 29, 2011, the Department received an Application for an Air Quality Permit Modification from ExxonMobil to incorporate a number of different portable diesel engines certified to EPA Tier 3 emission standards into the MAQP. The application included proposed limits on annual hours of operation for some of the proposed engines in order to keep the combined emissions from the permitting action below any New Source Review (NSR)/Prevention of Significant Deterioration (PSD) major source modification significant emission rate (SER) thresholds. The Department replied with an incompleteness letter on June 7, 2011, indicating that the engine emissions needed to be based on the most conservative Tier 3 standards based on the proposed permit conditions. ExxonMobil responded with a letter received June 29, 2011, that addressed the issues presented in the Incompleteness Letter. The proposed engines and operating conditions were as follows:

- Project #1: Add two portable emergency backup diesel engines not to exceed 500-hp each and limited to 1,500 hours per year each that are certified to EPA Tier 3 emission standards or better. These engines are likely to drive either air compressors or electric generators and would be used as emergency backup engines to existing electrical equipment.

- Project #2: Add three portable remediation activity diesel engines not to exceed 250-hp each with no limits on annual hours of operation that are certified to EPA Tier 3 emission standards or better. These engines would likely drive either air compressors or other equipment used for remediation projects.

- Project #3: Add miscellaneous portable diesel engines not to exceed 500-hp each and limited to a combined 2,100,000-brake horsepower-hours (hp-hrs) per year that are certified to EPA Tier 3 emission standards or better. In order to maximize operational flexibility, ExxonMobil proposed a limit on total hp-hrs rather than annual hour limits for each engine. Hp-hrs is equal to the engine's maximum rated hp multiplied by the actual hours of operation. The sum of the hp-hrs from each engine in Project #3 would be limited to 2,100,000-hp-hrs. These portable limited-use engines would likely drive either air compressors or electrical generators on an as-needed basis.

This permit action incorporated these engines and conditions. **MAQP #1564-24** replaced MAQP #1564-23.

On March 16, March 26, and March 29, 2012, the Department received elements from ExxonMobil that made up a complete application for an Air Quality Permit Modification.

To provide background information, on December 24, 2009, the Department received an application for an Air Quality Permit Modification from ExxonMobil to incorporate modifications to MAQP #1564-21. The requested changes included the addition of new VOC components. Because of the uncertainty associated with the current Montana de minimis rule (ARM 17.8.745) with respect to the rule having not yet been approved by EPA into Montana's SIP and the need to comply with internal company policy, ExxonMobil chose to group future VOC fugitive component additions and apply for a permit modification on that basis instead of using ARM 17.8.745 when such components were added in smaller increments and associated with separate projects.

On February 13, 2012, the EPA took final action to approve the de minimis rule into the SIP (FR Vol. 77, No. 29, pg. 7531-7534). As a result, ExxonMobil has requested the Department to remove permit conditions associated with installation, monitoring, and reporting of new fugitive VOC components.

This permit action removed these permit conditions. **MAQP #1564-25** replaced MAQP #1564-24.

E. Current Permit Action

On August 6, 2012, the Department received correspondence from ExxonMobil requesting that the Department amend the MAQP to change the emitting unit ID and description of the portable diesel-fired air compressor engine SE8 from "SLEB

Backup Air Compressor (SL/Port2)" to "Boiler House Backup Air Compressor (UT/Port2)". The compressor was originally located at the SLEB unit but will now be located at the boiler house.This permit action changes the emitting unit ID and description for SE8. **MAQP #1564-26** replaces MAQP #1564-25.

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 quotations 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 location 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 includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

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

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

4. ARM 17.8.110 Malfunctions. (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.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means which, without resulting in reduction of the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner that a public nuisance is created.

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

1. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
2. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
3. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
4. ARM 17.8.213 Ambient Air Quality Standard for Ozone
5. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
6. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
7. ARM 17.8.221 Ambient Air Quality Standard for Visibility
8. ARM 17.8.222 Ambient Air Quality Standard for Lead
9. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}
10. ARM 17.8.230 Fluoride in Forage

ExxonMobil 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. 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. This rule requires an opacity limit of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, ExxonMobil 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 17.8.324(3) Hydrocarbon Emissions--Petroleum Products. 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, or is a pressure tank as described in (1) of this rule.

5. ARM 17.8.340 Standard of Performance for New Stationary Sources. This rule incorporates, by reference, 40 CFR Part 60, NSPS. ExxonMobil is considered an NSPS affected facility under 40 CFR Part 60 and is subject to the requirements of the following Subparts.

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

   b. 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.

c. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, shall apply to boiler B-8 Temp and B-8 and any other affected equipment.

d. Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels. This Subpart shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984. These requirements shall be as specified in 40 CFR Part 60.110b through 60.117b.

e. Subpart UU, Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture. This Subpart applies to each asphalt storage tank that commences construction or modification after November 18, 1980. Tank #55 will be subject to these requirements and will be required to meet 0% opacity limit, except for one 15-minute period each 24 hour period.

f. Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006. ExxonMobil will comply with Subpart GGG, as applicable, for the Fluid Coker project, Hydrofiner #1 (HF-1), the Hydrofiner #3 (HF-3), and the PMA project.

g. Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006. ExxonMobil will comply with Subpart GGGa, as applicable, for C-310 and any other affected sources.

h. Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems. This rule pertains to facilities that are constructed or modified after May 4, 1987. The affected facilities include an individual drain system, an oil-water separator, and an aggregate facility (drain system included with downstream sewer lines and oil-water separators).

i. Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Compression Engines (CI ICE). Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are manufactured after April 1, 2006, and are not fire pump engines or are manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006, and owners and operators of stationary CI ICE that modify or reconstruct their stationary CI ICE after July 11, 2005, are subject to this subpart. Emergency Engines SE7-SE12 are all subject to this subpart.

6. ARM 17.8.341 Standards of Performance for Hazardous Air Pollutants. The source shall comply with the standards and provisions of 40 CFR Part 61, as appropriate.

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

b. Subpart FF, National Emission Standards for Benzene Waste Operations. The source shall comply with the standards and provisions of 40 CFR 61, Subpart FF, as appropriate.

7. 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 appropriate.

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

   b. Subpart Q, National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers. This regulation applies to the usage of chromium-based water treatment chemicals.

   c. Subpart CC, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries (Refinery MACT I). This regulation applies to petroleum refining process units and to related emission points as specified in this Subpart.

   d. Subpart UUU, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (Refinery MACT II). This regulation applies to petroleum refining process units and to related emission points as specified in this Subpart.

   e. Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE). An owner or operator of a stationary reciprocating internal combustion engine (RICE) at a major or area source of HAP emissions is subject to this rule except if the stationary RICE is being tested at a stationary RICE test cell/stand. An area source of HAP emissions is a source that is not a major source. All of the RICE are affected units under this subpart because the facility is a major source of HAP emissions.

D. 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 fee is not required for the current permit action because the permit action is considered an administrative permit change.

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 contaminant holding an air quality permit (excluding an open-burning permit) issued by the Department; and the annual 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.

E. 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. ExxonMobil has a PTE greater than 25 tons per year of PM, particulate matter with an aerodynamic diameter 10 microns or less (PM_{10}), 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. A permit application was not required for the current permit action because the permit change is considered an administrative permit change. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. An affidavit of publication of public notice was not required for the current permit action because the permit change is considered an administrative permit change.

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 ExxonMobil 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.

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

1. ARM 17.8.801 Definitions. ExxonMobil's existing Billings petroleum refinery (including both the refinery and the bulk terminal) is defined as a "major stationary source" because it is a listed source with the PTE more than 100 TPY of several pollutants (SO_2, CO, NO_X, and VOCs).

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.

   No emissions increases are anticipated as a result of this permitting action; therefore, the Department has determined that ExxonMobil is not subject to PSD permitting for this permitting action.

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

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

   a. PTE > 100 tons/year of any pollutant;

   b. PTE > 10 tons/year of any one Hazardous Air Pollutant (HAP), PTE > 25 tons/year of a combination of all HAPs, or a lesser quantity as the Department may establish by rule; or

   c. PTE > 70 tons/year of PM_{10} in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #1564-23 for ExxonMobil, the following conclusions were made:

   a. The facility's PTE is greater than 100 tons/year for several pollutants.

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

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

   d. This facility is subject to NSPS requirements.

   e. This facility is subject to current NESHAP standards.

   f. This source is not a Title IV affected source, nor a solid waste combustion unit.

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

   Based on these facts, the Department determined that ExxonMobil is a major source of emissions as defined under Title V. ExxonMobil's current Operating Permit, #OP1564-07, became final on February 28, 2012.

III. BACT Determination

A BACT determination is required for each new or modified source. ExxonMobil 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 used.

A BACT determination was not required for the current permit action because the permit change is considered an administrative permit change.

IV. Emission Inventory

No changes in emissions are associated with this permitting action. Emissions inventories from previous permitting actions are on file with the Department.

V. Existing Air Quality

ExxonMobil is located at 700 Exxon Road, Billings, Montana in the S½ of Section 24 and the N½ of Section 25, Township 1 North, Range 26 East in Yellowstone County. This area is considered attainment for all criteria pollutants, including ozone (for which VOC is a precursor). The Laurel SO_2 nonattainment area is nearby. The Laurel SO_2 nonattainment area is about 31.9 kilometers (19.8 miles) southwest from the center of the main operating facility.

VI. Ambient Air Impact Analysis

The Department determined that there will be no impact from this permitting action as no new emissions will result with implementation of this permitting action. The Department believes the permitting action will not cause or contribute to a violation of any ambient air quality standard.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted 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

This permitting action will not result in an increase of emissions from the facility and is considered an administrative action; therefore, an environmental assessment is not required.

Analysis Prepared By: Ed Warner
Date: 9/12/12