MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OPERATING PERMIT TECHNICAL REVIEW DOCUMENT

Permitting and Compliance Division
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ExxonMobil Refining and Supply Company
Billings Refinery
S ½ of Section 24 and N ½ of Section 25, Township 1 North, Range 25 East, Yellowstone County
700 Exxon Road
Billings, MT 59103

The following table summarizes the air quality programs testing, monitoring, and reporting requirements applicable to this facility.

Facility Compliance Requirements	Yes	No	Comments
Source Tests Required	X		Methods 1-4, 5, 6/6C, 9, 10 &11
Ambient Monitoring Required		X	Monitoring is being conducted on a voluntary basis under the auspices of BLAQTC
COMS Required	X		FCC CO Boiler Stack, Coker CO Boiler Stack
CEMS Required	X		H_2S and SO_2
Schedule of Compliance Required		X	
Annual Compliance Certification and Semiannual Reporting Required	X		
Monthly Reporting Required		X	
Quarterly Reporting Required	X		In accordance with the Stipulation
Applicable Air Quality Programs			
ARM Subchapter 7 Preconstruction Permitting	X		Permit #1564-13
New Source Performance Standards (NSPS)	X		Subparts J, Kb, and GGG
National Emission Standards for Hazardous Air Pollutants (NESHAPS)	X		
Maximum Achievable Control Technology (MACT)	X		
Major New Source Review (NSR)/Prevention of Significant Deterioration (PSD)	X		ExxonMobil is defined as a major source but has not yet triggered a PSD/NSR review
Risk Management Plan Required (RMP)	X		Submitted to EPA on 6/21/99
Acid Rain Title IV		X	
State Implementation Plan (SIP)	X		Billings/Laurel SO_2 Control Plan

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SECTION I. GENERAL INFORMATION

A. Purpose

This document establishes the basis for the decisions made regarding the applicable requirements, monitoring plan, and compliance status of emissions units affected by the operating permit proposed for this facility. The document is intended for reference during review of the proposed permit by the U.S. Environmental Protection Agency (EPA) and the public. It is also intended to provide background information not included in the operating permit and to document issues that may become important during modifications or renewals of the permit. Conclusions in this document are based on information provided in the original application submitted by ExxonMobil Refining & Supply Company (ExxonMobil) on June 12, 1996; additional submittals on March 23, 2000, April 24, 2000, and April 25, 2000; a significant modification application submitted on August 21, 2000, with additional information submitted on November 13, 2000 and November 22, 2000; and a significant modification application submitted on February 13, 2002.

B. Facility 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 Highway 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 of Township 1 North, Range 25 East in Yellowstone County. The Montana Rail Link railroad tracks transect the refinery product storage tanks lying south of the railroad right-of-way and the remainder of the refinery lying north of the tracks. The active refinery occupies approximately 380 acres on a level plot with an elevation of approximately 3091 feet (Mean Sea Level). Exxon Road, which provides access to the refinery, is paved. Parking lots and roadways within the active portion of the site are also paved. The refinery lies east of the Billings City Limits in an area zoned Heavy Industrial. A 5- to 7-foot high chain link fence, topped with 1 foot of three strands of barbed wire and 24-hour guards provide security.

C. Facility Background Information

The Exxon Company U.S.A Billings Refinery (Exxon) requested a modification to **Permit #1564A2** to support the Yellowstone Energy Limited Partnership (YELP) permit. The permit modification was given **Permit #1564-03**. That request was addressed under the provisions of Subchapter 7, ARM 17.8.733(1)(b) (now ARM 17.8.764). 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 lb/MMBtu sulfur limit to 0.96 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; and (5) provide additional verification of sulfur dioxide emission reductions by the addition of recording devices on the 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 permit would reduce SO_2 emissions into the Billings air shed. This reduction takes place as a result of the coker process gas emissions, which include SO_2, CO, coke fines, reduced sulfur compounds and NOx 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 coker CO boiler (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 has been changed from 1.1 to 0.96 lbs. of sulfur-in-fuel per million BTUs fired. This change has been equated to a 100-ton-per-year offset based on actual SO_2 emissions for the past 2 years. In addition, Exxon has 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 EPA because of the difficulty in meeting the federal definition of federally enforceable emission limits. Logic suggests that if the YELP facility operates as expected and provides 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 was critical for both YELP and Exxon to coordinate their activities closely once operation of YELP commenced. The Exxon proposal was based on the attached information and more fully explains the 100-ton-per-year figure and also the rationale for the block hourly 0.96 lbs. of sulfur-in-fuel figure calculated on a refinery-wide basis.

Exxon requested that the Department of Environmental Quality (Department) consider revising the permit when the new 213-foot stack at Montana Sulphur and Chemical Company (MSCC) is constructed and made federally enforceable. This increase in stack height decreases MSCC's ambient impacts and could decrease 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 must be made federally enforceable through a modification of MSCC's air quality permit. Further, the Department believed the increased stack height may be necessary to address concerns with the current State Implementation Plan (SIP) and, therefore, may not be available to reduce the required emission offset at Exxon.

On November 12, 1994, Exxon was issued **Permit #1564-04** to construct and operate an 800-ton/day Polymer Modified Asphalt (PMA) unit. The PMA unit allows Exxon to produce polymerized asphalt. Conventional asphalt base stock is mixed with solid polymer pellets in a wetting/mixing tank, ground with a shear 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 pollutant 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). The modification allowed Exxon to use the computer system to collect and archive the fuel data to meet permit conditions.

On August 25, 1995, Exxon was issued **Permit #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 Drum Atmospheric Vent is 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 are vented to this drum. Inside the drum, a continuous flow of water cools any safety valve releases or blowdowns to condense vapors for subsequent treatment in the wastewater treatment plant. Any vapors not condensed, exit through the D-4 Drum Atmospheric Vent stack.

On January 14, 1996, Exxon was issued **Permit #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 State Implementation Plan, Exxon and the

Department have 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 will receive a Good Engineering Practices (GEP) credit for modeling purposes of 65 meters. Exxon shall be entitled to a greater GEP credit for either stack if a physical demonstration (fluid model or field study) is conducted and justifies a taller GEP stack height.

On June 17, 1996, the Department issued **Permit #1564-07** to modify the opacity limitations for the wetting/mixing tank exhaust vent in the PMA unit. The requirements of 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS) and 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 is used for mixing only and does not store asphalt; therefore, it does not meet the definition of a storage tank. The opacity limit set in the original permit was representative of an asphalt tank used for storage of asphalt as defined under NSPS, Subpart UU. However, the permitted opacity limit did not recognize the fact that mixing asphalt is occurring in the mixing tank. Due to mixing, there may be a noticeable opacity at the wetting/mixing tank top, even when mixing temperatures are well below 400º F.

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

Exxon still needs to maintain the operating temperature of the wetting/mixing tank below the smoking point of the asphalt in order to comply with a 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 July 7, 1999, Exxon was issued **Permit #1564-08** to bring the permit closer to the requirements of the June 12, 1998, Stipulation between Exxon, the Department, and the Board of Environmental Review. The proposed 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 Permit #1564-08. The specific changes to the permit and consolidated permits are outlined in the permit analysis section of Permit #1564-08.

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 Permit #1564-08:

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

Several other administrative changes were made during this permit action. The following changes were incorporated into this permit, as well:

1. Removal of condition II.E.7 (Odors), based on ARM 17.8.717, from Exxon's permit, so it remains solely state enforceable.
2. A name change from Exxon Company U.S.A. to ExxonMobil received January 7, 2000).

3. 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."
4. Reorganization of Section II of the permit.
5. 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. **Permit #1564-09** reflected all of the above changes and replaced Permit #1564-08.

Permit #1564-10 was not issued. Two applications were received within the same time period to alter Permit #1564-09 and were not issued in the order in which they were received. To avoid confusion in referencing these permit applications and actions, Permit #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 Prevention of Significant Deterioration (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. As these generators were temporary, the Title V permit was not modified to include them. **Permit #1564-11** replaced Permit #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. Again, as this generator was temporary, the Title V permit was not modified to include it. **Permit #1564-12** replaced Permit #1564-11.

ExxonMobil was issued a final and effective Title V permit on December 2, 2001 (Permit **OP1564-00**).

On February 13, 2002, the Department received a permit application to address emission increases associated with the proposed modifications to allow approximately 500 barrels per day more fresh feed to be processed through the Fluid Coker unit (Coker). Other units/processes that would be affected by the proposed modifications include 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 is a limit on refinery-wide fuel oil combustion used to keep the overall SO_2 emissions increase from the project below the Prevention of Significant Deterioration (PSD) of Air Quality SO_2 significance levels. In addition, a contemporaneous decrease in Volatile Organic Compound (VOC) emissions on Tank #309 would offset the increase in VOC emissions from the project, to keep the project below PSD VOC significance levels.

The project involves 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 will increase from 6 inch to 8 inch in diameter and allow 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. Upgrade 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. Install new steam aeration nozzles and replace appropriate sections of the scouring coke line from the Coker burner to the reactor. This will allow improved coke circulation and avoid excessive coke buildup at the Coker area (maintenance related);
4. Install a multi-hole orifice chamber in the Coker Process Gas line that goes to either BGI or the Coker CO Boiler. This device stabilizes the back-pressure that the slide valves, located on the top of the Coker burner vessel, will have to control. This device will allow 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. Modify 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. Modify 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. Modify 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 impellars, both pressure and increased capacity requirements are satisfied without having to replace the pumps. The bearing housings will be upgraded, if necessary, to safely achieve these higher speeds (capacity related);
8. Modify the reactor feed nozzle system with an improved design. The intent of these changes will be to optimize the Coker unit feed nozzle system operation (capacity related); and

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

Permit #1564-13 replaces Permit #1564-12.

D. Current Permit Action

The current permit action incorporates the changes made to the Montana Air Quality Permits (MAQP, formerly preconstruction) #1564-09 and #1564-13. As mentioned above, Permit #1564-10 was not issued. Permits #1564-11 and #1564-12 involved temporary sources, and, therefore, the Title V permit was not updated to include those sources. In addition, upon review of OP1564-00, the Department discovered that an applicable requirement from the MAQP was not included in the Title V permit. That requirement (a 0.96 lb/MMBtu limit on sulfur in the refinery fuel gas) has been superseded by other requirements listed in the permit, but is still applicable, and needs to be included. Permit **OP1564-01** replaces OP1564-00.

E. Taking and Damaging Analysis

HB 311, the Montana Private Property Assessment Act, requires analysis of every proposed state agency administrative rule, policy, permit condition or permit denial, pertaining to an environmental matter, to determine whether the state action constitutes a taking or damaging of private real property that requires compensation under the Montana or U.S. Constitution. As part of issuing an operating permit, the Department is required to complete a Taking and Damaging Checklist. As required by 2-10-101 through 105, MCA, the Department has conducted a private property taking and damaging assessment and has determined there are no taking or damaging implications. The checklist was completed on September 16, 2003.

F. Compliance Designation

The Department annually inspects all major facilities. The ExxonMobil Refinery was last inspected on September 23, 2003, and found to be in compliance with all applicable requirements.

SECTION II. SUMMARY OF EMISSION UNITS

A. Facility Process Description

ExxonMobil operates a greater than 52,000-barrel-per-day petroleum refinery designed to process high sulfur crude oil. Major Processing equipment includes:

1. Atmospheric and vacuum crude distillation towers
2. Fluidized Catalytic Cracker
3. Hydrocracker/Hydrogen Plant
4. Fluid Coker
5. Naphtha Fractionator
6. Catalytic Reformer
7. Hydrofluoric Alkylation Unit
8. Three Hydrotreaters for polishing the distillate streams

ExxonMobil does not have a sulfur recovery unit at this refinery. Refinery gases high in H_2S are piped to an off-site sulfur recovery plant owned and operated by MSCC. MSCC has an Amine unit to treat the sour fuel gas and return the sweet refinery fuel gas to ExxonMobil.

B. Emission Units and Pollution Control Device Identification

EU01: Crude - APS and VPS

The #1 Crude unit fractionates or separates petroleum crude oils into fractions including gas, naphtha, distillate, gas oil and residuum, with the lightest molecules at the top of the fractionating tower and the heaviest molecules at the bottom of the tower. The heavy "bottoms" from the first fractionation tower are further fractionated in a vacuum tower.

<u>EU1a: F-2 Crude Vacuum Heater Stack (F-1 Crude Furnace/ F-401 Vacuum Heater).</u> This unit is a process heater that heats crude and reduced crude oil for the fractionation process. This stack is monitored by a CEMS on the refinery fuel gas header.

<u>EU1b: F-3 Heater Stack</u>. This unit is a process heater that heats crude for the oil fractionation process. This stack is monitored by an H_2S CEMS on the refinery fuel gas header.

<u>EU1c: D-4 Drum Atmospheric Stack.</u> This unit is a safety device to control and manage both routine and abnormal process unit releases.

EU02: HF #2/3 – Hydrofining Units #2 & #3

This unit desulfurizes naphtha and/or distillate by reaction with hydrogen over a catalyst.

<u>EU2a: F-3x Heater Stack and EU2b F-5 Heater Stack</u>. These units are process heaters that heat naphtha and/or distillates for the desulfurization process. These stacks are monitored by an H_2S CEMS on the refinery fuel gas header.

EU03: Coker - Fluid Coker

This unit thermally cracks residuum into materials including gases, naphtha, gas oils and coke using a fluidized coke. The primary control is the YELP process.

EU3a: KCOB - Coker CO Boiler Stack. This unit is a steam boiler, which may burn coker process gases in addition to supplemental fuel. There is an opacity and stack flow and SO_2 CEMS monitors on this stack.

EU3b: F-202 - Heater Stack. This unit is a process furnace that super heats used steam in the fluid coking process. This stack is monitored by an H_2S CEMS on the refinery fuel gas header.

EU04: POFO - Powerforming Unit

This unit reforms low octane naphtha into high-octane gasoline using a catalyst.

EU4a: F-700 Heater Stack. This unit is a process heater that heats naphtha for the reforming process. This stack is monitored by an H_2S CEMS on the refinery fuel gas header.

EU05: Alky/Splitter/Rerun/Diene - Alkylation Unit, Alky Feed Treater, Rerun of Alkylate for Avgas

This unit alkylates olefins and butane into gasoline and blends stocks using HF acid as a catalyst.

EU5a: F-402 Heater Stack. This unit is a hot oil heater that heats a circulating diesel material used to exchange heat to other hydrocarbons for fractionation and other process heating requirements. The Hot Oil Furnace Stack is monitored by an H_2S CEMS on the refinery fuel gas header.

EU06: Treater - Cat Naphtha Caustic Treater (Merox Unit) after Cat Cracker

This unit sweetens Naphtha from the FCC. There is no control equipment associated with this unit. These emissions are primarily fugitive VOCs and HAPs.

EU07: HF#1

This unit desulfurizes distillates using hydrogen and a catalyst.

EU7a: F-201 Heater Stack. This unit is a process heater that heats distillates and hydrogen for the desulfurization process. This stack is monitored by an H_2S CEMS on the refinery fuel gas header.

EU08: DEC2 - Deethanizer Unit

This unit separates liquefied petroleum gas from methane and ethane via fractionation. There is no control equipment associated with this unit. These emissions are fugitive VOCs.

EU09: FCCU - Cat Cracking Unit

This unit catalytically cracks heavy petroleum gas oils into lighter materials including gas, naphtha, olefins, and cycle oils using a circulation bed of fluidized catalyst.

EU9a: CCOB Stack - FCC CO Boiler Stack. This unit is a steam boiler, which may burn cat cracker process gases in addition to supplemental fuels. This stack has both an opacity monitor and an SO_2 CEMS.

EU10: ULEB/SLEB - Unsaturated Light Ends Unit, Saturated Light Ends Unit, Sour Water Strippers, Gas Compression

This unit fractionates and sweetens saturated and unsaturated light ends like fuel gas, propanes, butanes, and light fractions of gasoline. There is no control equipment for this unit.

EU11: HCBL - Hydrocracking Unit

This unit hydrogenates gas oils into naphtha and distillates in the presence of hydrogen and a catalyst in the hydrocracking process.

EU11a: F-651 Heater Stack. This unit is a process heater that heats feedstock for the hydrocracking process. This stack is monitored by an H_2S CEMS on the refinery fuel gas header.

EU12: H_2 Plant/HRUB - H_2 Plant, H_2 Upgrade (Recovery) Facility, MDU Replacement

This unit manufactures and purifies hydrogen, produces a gas stream that is used as a replacement for natural gas, and produces carbon dioxide.

EU12a: F-551 Heater Stack. This unit is a gas-fired, steam-reforming heater that contains a catalyst and manufactures hydrogen. This stack is monitored by an H_2S CEMS on the refinery fuel gas header.

EU13: Utilities - Air Compressors/Dryers, Boiler Feed Water

This unit includes equipment to treat boiler feedwater, generate steam, and produce compressed air for use in the refining processes.

EU13a: B-8 Standby Boiler House Stack. This unit is a steam boiler that is monitored by an H_2S CEMS on the refinery fuel gas header.

EU14: OM&U - Oil Movements & Utilities, Wastewater, High Pressure Natural Gas, Refinery Fuel Gas Supply

This unit consists of the flare system, wastewater system, natural gas supply system, refinery fuel gas system, cooling towers and N_2 distribution system

EU14a: Flare and Turnaround Flare. This unit is a flare for combustion of emergency gaseous hydrocarbon releases. The Turnaround flare is used only when the primary flare is not operating.

EU14b: F-10 Stack – Heater. This unit is a gas-fired storage tank heater which heats circulating oil. This unit fires only sweetened fuel.

EU15: OM&S/PMAU - Oil Movements & Shipping/Asphalt PMAU

This unit includes petroleum storage tank farms and the polymer modified asphalt unit. All non-unit specific storage tanks are included in this unit which consists of about 80 tanks of various sizes and four spheres and four horizontal propane storage vessels.

EU16: Low Sulfur MoGas

This unit reforms low octane naphtha into high-octane gasoline using a catalyst.

EU16a: F-1201 Heater Stack. This unit is a process heater in support of the low sulfur motor gasoline process. This stack is monitored by an H_2S CEMS on the refinery fuel gas header and is required to have ultra low NO_x burners.

C. Categorically Insignificant Sources/Activities

Emission Unit ID	Description
IEU01	Warehouse building heater
IEU02	Mechanical building heater
IEU03	Operations Control Center building heater
IEU04	FCCU/HCBL Shelter heater
IEU05	Diesel Fire water pumps (2)
IEU06	Gasoline Fire water pumps (2)
IEU07	Laboratory building heater
IEU08	Laboratory equipment testing emissions
IEU09	Gasoline knock engines (3)
IEU10	Main office building heater
IEU11	Trailer heating units (8)
IEU12	Land Treatment Unit tilings/waste application
IEU13	Diesel driven cranes/lifts/trucks
IEU14	Portable diesel/gasoline pumps/compressors
IEU15	Product Coke storage tank
IEU16	Propane/Butane car/truck relief
IEU17	Propane odorant facility

SECTION III. PERMIT CONDITIONS

A. Emission Limits and Standards

Emission limits and standards in the Title V operating permit were established by ExxonMobil's Preconstruction Permit (#1564-13), the Billings/Laurel SIP, NSPS requirements, NESHAP requirements, and MACT requirements. The definitions of terms apply to where the limit or condition was derived from. If a condition is placed in the permit from the SIP, then the definition that applies to that condition would be the SIP definition.

B. Monitoring Requirements

ARM 17.8.1212(1) requires that all monitoring and analysis procedures or test methods required under applicable requirements are contained in operating permits. In addition, when the applicable requirement does not require periodic testing or monitoring, periodic monitoring must be prescribed that is sufficient to yield reliable data from the relevant time period that is representative of the source's compliance with the permit.

The requirements for testing, monitoring, recordkeeping, reporting, and compliance certification sufficient to assure compliance does not require the permit to impose the same level of rigor for all emissions units. Furthermore, it does not require extensive testing or monitoring to assure compliance with the applicable requirements for emissions units that do not have significant potential to violate emission limitations or other requirements under normal operating conditions. When compliance with the underlying applicable requirement for an insignificant emissions unit is not threatened by lack of regular monitoring and when periodic testing or monitoring is not otherwise required by the applicable requirement, the status quo **(i.e., no monitoring)** will meet the requirements of ARM 17.8.1212(1). Therefore, the permit does not include monitoring for insignificant emissions units.

The permit includes periodic monitoring or recordkeeping for each applicable requirement. The information obtained from the monitoring and recordkeeping will be used by the permittee to periodically certify compliance with the emission limits and standards. However, the Department may request additional testing to determine compliance with the emission limits and standards.

C. Test Methods and Procedures

The operating permit may not require testing for all sources if routine monitoring is used to determine compliance, but the Department has the authority to require testing if deemed necessary to determine compliance with an emission limit or standard. In addition, ExxonMobil may elect to voluntarily conduct compliance testing to confirm its compliance status.

All requirements to perform any type of test in this permit were previously established by ExxonMobil's MAQP #1564-13, the Billings/Laurel SIP, NSPS requirements, NESHAP requirements, and MACT requirements, except for the requirement to perform test on the FCC CO boiler and the Coker CO boiler. This permit requires Method 9 tests (as required by the Department) and biannual Method 5 tests to be performed on the FCC CO boiler and the Coker CO boiler. These testing requirements were established by the Department's testing policy.

D. Recordkeeping Requirements

ExxonMobil is required to keep all records listed in the operating permit as a permanent business record for at least five years following the date of the generation of the record.

E. Reporting Requirements

Reporting requirements are included in the permit for each emissions unit and Section V of the operating permit "General Conditions" explains the reporting requirements. ExxonMobil is required to submit quarterly, semi-annual, and annual monitoring reports to the Department and to annually certify compliance with the applicable requirements contained in the permit. The reports must also include a list of all emission limit and monitoring deviations, the reason for any deviation, and the corrective action taken as a result of any deviation.

To eliminate redundant reporting, a source may reference previously submitted reports (with at least the date and subject of the report) in the semi-annul and annual reports instead of resubmitting the information in monthly, quarterly, and/or other reports. However, a source must still certify continuous or intermittent compliance with each applicable requirement annually.

F. Public Notice

In accordance with ARM 17.8.132, a public notice was published in the *Billings Gazette* newspaper on November 3, 2003. The Department provided a 30-day public comment period on the draft operating permit from November 3, 2003, to December 3, 2003. ARM 17.8.1232 requires the Department to keep a record of both comments and issues raised during the public participation process.

Summary of Public Comments for OP1564-01

Person/Group Commenting	Comment	Department Response
No comments received.		

G. Draft Permit Comments

On December 3, 2003, the Department received comments from ExxonMobil on the Draft Operating Permit #OP1564-01 for their Billings facility. Those comments and the Department's response are included in the following table.

Summary of Permittee Comments for OP1564-01

Permit Reference	Permittee Comment	Department Response
General Comments		
Throughout the permit	ExxonMobil does not agree that the requirements of the Montana Source Test Protocol and Procedures Manual constitute valid permit conditions and are concerned that changes in the permit, via changes in the manual, could be made without proper rulemaking and/or permitting.	The Montana Source Test Protocol and Procedures Manual is applicable under ARM 17.8.106. In OP1564-00, the Department added ARM 17.8.106, an applicable requirement, to Section III.A, Facility Wide Requirements as Section III.A.1. This section specifies use of the current (July 1994) version of the Montana Source Test Protocol and Procedures Manual, unless this version is superseded by rulemaking (which is the only way to update the Manual per ARM 17.8.106). All other references to the Source Test Protocol in OP1564-00 were changed to Section III.A.1. This will remain in OP1564-01.
Condition A.26 and Section V.B.2	Annual certifications are required by the listed conditions within 30 days of the end of the compliance period. In addition, a semi-annual report is also to be submitted at	The Department has reviewed the condition requiring submittal of annual certifications and semi-annual monitoring reports within 30 days of the end of the

	the same time. ExxonMobil requests that 60 days be allowed to complete such a complex review for the annual certification report.	compliance period. The Department has decided that 45 days is more appropriate, allowing permittees more time to put together the complex reports, without jeopardizing timeliness for compliance review.
Throughout the permit	ExxonMobil requests that references to conditions within conditions be eliminated as they could subject ExxonMobil to a double jeopardy situation.	Where this is possible, it has been done. In several cases, (the Billings/Laurel SO_2 Control Plan, for example, that is the underlying requirement for Sections III.C.13 and III.P.11), references to conditions within conditions cannot be removed without altering the originating document, and therefore, have been left intact.
Throughout the permit	ExxonMobil's name has changed. ExxonMobil requests that all "Exxon" references be changed to "ExxonMobil."	The correction has been made.
Section I	*General Information*	
	There is a new facility contact. Revise the "Facility Contact Person" to B.M. Gieser at 406-657-5343.	The correction has been made.
Section III	*Permit Conditions*	
A.20	Based on EPA guidance and a conservative reinterpretation of Subpart FF applicability, streams not previously included in the TAB were included in the TAB. Thus the refinery for the first time is apparently subject to control requirements of 40 CFR 61, Subpart FF. Change wording as described in comments to reflect this change.	The wording has been revised.
A.21	Refinery MACT contains provisions to reduce the regulatory burden of equipment that is subject to multiple equipment leak standards (40 CFR 63.640(p)). The provisions should be made part of the permit to ensure they are available to ExxonMobil. Add sentence as described in comments to accomplish this.	The appropriate language has been added.
B.5	The units for the fuel oil firing limitation are not correct.	The units have been corrected.
B.12	The recordkeeping requirement should allow flexibility for recordkeeping in accordance with existing practice including electronic records.	The wording has been revised.
C.21.f and other similar requirements	This comment applies to every Section III EU where this condition appears. The wording is not clear. Revise language as described in comments.	The wording has been revised.
D.5, D.9, D.12, D.14 and similar sections in other emitting units	This comment applies to EU02, EU04, EU05, EU11, EU15, and EU16, all which have similar language. These EUs do no have any Group 1 MPV's so the permit conditions are not required. Delete the listed conditions and similar conditions in all of the applicable EUs.	The MPV conditions have been deleted from EU02, EU04, EU05, EU11, EU15, and EU16.
E.13 and E.14	ExxonMobil has installed an SO_2 CEM and flow meter on the Coker CO Boiler stack, making these permit conditions obsolete. Delete conditions E.13 and E.14.	E.14 has been deleted and replaced with other appropriate SIP conditions that reflect the SO_2 CEM. E.13 was unrelated to this issue, and was not deleted.

F	In a number of new conditions referencing F-700, this furnace was not modified with Low Sulfur Mogas (LSM). This furnace may be modified in the future. Since the furnace has not been modified, these conditions should not take effect until the modifications have taken place. This was the intent when the preconstruction permit was issued. Insert language indicating the condition does not take effect until the furnace is modified into conditions F.3-F.6, F.11-F-15, and F.19-F.20.	Clarifying language has been added.
F.7, F.16, F.21, and F.24.e	There is a stream in the Powerformer that has greater than 10 wt% benzene and therefore is subject to the equipment leak requirements at 40 CFR 61, Subparts J and V. Provisions for this should be inserted into each of the equipment leak conditions as appropriate. However, since the stream is also subject to the requirements in 40 CFR 63, Subpart CC, then only the provisions in CC need bee complied with (See Section III.A.21). Add language as described in comments, and include similar additions to F.16, F.21, and F.24.e.	The requested language has been added.
F.11, F.19, and F.24	F.11 and other conditions that refer to it contain language that has no basis in the preconstruction permit. Compliance will be demonstrated by stack testing. Delete these conditions.	Although the Department has the authority to determine compliance demonstrations based on assuring compliance, in this case, stack testing is the appropriate demonstration (because the UNLBs are intrinsic to the furnace). The conditions mentioned have been deleted.
F.24.d	The condition as written requires ExxonMobil to verify compliance with Subpart J for the semiannual report. The semi-annual report should only require verification of recordkeeping and reporting requirements. Revise condition as described in comments.	The language has been revised.
K.11	FCC scheduled turnarounds are now targeted 60 months apart, versus the 48 months at the time the SIP was written. The feed meter orifice can only be removed when the FCC is down. Replace “48” with “60” in the next to the last sentence.	The Department cannot alter the condition because it is the verbatim requirement of the Billings/Laurel SO_2 SIP. The Department cannot alter underlying applicable requirements through the Title V permit. The Department suggests making note of this discrepancy in ExxonMobil’s annual certification reports. When the SIP is updated, this information can be included, and the Title V changed.
O	Previous communication with MDEQ has confirmed that B-8 as an NSPS boiler is subject to Subpart J requirements. Therefore, the appropriate conditions must be added. Add language equivalent to conditions as is in EU16 Low Sulfur Mogas.	Subpart J requirements have been added to this section.
Q.13	ExxonMobil has submitted a request to the MDEQ to revise the Tank 26 emissions formula to make it more accurate. Replace the old emissions formula with the one described in comments.	The equation has been updated.
Q.34.e	The condition as written requires ExxonMobil to verify compliance with Subpart CC for the semi-annual report. The semi-annual report should only require	The language has been revised.

	verification of recordkeeping and reporting requirements. Revise the language as described in comments.	
R (Table)	The permit limit for R.1 should be 20% opacity since it is a new furnace. Revise the table opacity limits to be consistent with condition R.1.	The correction has been made.
R.11, R.19, R.24.b	R.11 and the other conditions that refer to it contain language that have no basis in the preconstruction permit. Compliance will be demonstrated by stack testing. Delete these conditions.	Although the Department has the authority to determine compliance demonstrations based on assuring compliance, in this case, stack testing is the appropriate demonstration (because the UNLBs are intrinsic to the furnace). The conditions mentioned have been deleted.
Section IV	*Non-Applicable Requirements*	
B	Subpart GGG applies to the LSM unit.	The correction has been made.
Section V	*General Conditions*	
D.3	Dates are not consistent with the existing permit. Revise dates as described in comments.	The dates have been corrected.
Appendices		
Appendix A	In the Table of Insignificant Emitting Units, IEU16 is more accurately identified as both propane and butane car/truck relief. Add "butane" as described in the comments.	The correction has been made.
Technical Review Document		
Section I.A	As part of the referenced dates, those related to the LSM project should be included since all the LSM requirements were added to this draft permit. Add dates as described in comments.	The correction has been made.
Section II.C	In the Table of Insignificant Emitting Units, IEU16 is more accurately identified as both propane and butane car/truck relief. Add "butane" as described in the comments.	The correction has been made.
Section II.B.EU3a	Since ExxonMobil has triggered a SIP provision requiring the installation of an SO_2 CEM and stack flow monitor, add the language as described in the comments.	The correction has been made.
Section IV.C (Table)	Subparts J, V, and FF are applicable to the refinery. Remove them from the list.	The correction has been made.
Section IV.D (Table)	This table repeats the 40 CFR 61 subparts rather than listing the 40 CFR 63 subparts. Include the table from the existing permit.	The correction has been made.
Section V.B	See permit condition III.A.20 for discussion of Subpart FF.	The language has been updated.

Summary of EPA Comments for OP1564-01

Permit Reference	EPA Comment	Department Response
No comments received.		

SECTION IV. NON-APPLICABLE REQUIREMENT ANALYSIS

A. Requirements Not Identified as Non-Applicable

Pursuant to ARM 17.8.1221, ExxonMobil requested a permit shield for all non-applicable regulatory requirements and regulatory orders identified in the tables in Section 8 of Permit Application OP1564-00. In addition, that application also requested a permit shield for both the facility and for certain emission units. The Department has determined that the requirements identified in the permit application for the individual emission units are non-applicable. These requirements are contained in the permit it Section IV – Non-applicable Requirements.

The following table outlines those requirements that ExxonMobil had identified as non-applicable in Permit Application OP1564-00, but will not be included in the operating permit as non-applicable. The table includes both the applicable requirement and reason that the Department did not identify this requirement as non-applicable.

Applicable Requirement	Reason for Not Including
Sub-Chapter 3 Emission Standards	
ARM 17.8.326 Prohibited Materials for Wood or Coal Residential Stoves	This rule may not be applicable to the source at this time; however, it may become applicable during the life of the permit.
Sub-Chapter 6 Open Burning	
ARM 17.8.601 Definitions ARM 17.8.602 Incorporations by Reference	These are rules that consist of either a statement of purpose, applicability statement, regulatory definitions or a statement of incorporation by reference. These types of rules do not have specific requirements associated with them.
ARM 17.8.604 Prohibited Open Burning --When Permit Required ARM 17.8.605 Special Burning Periods ARM 17.8.606 Minor Open Burning Source Requirements ARM 17.8.610 Major Open Burning Source Restrictions ARM 17.8.611 Emergency Open Burning Permits ARM 17.8.612 Conditional Air Quality Open Burning Permits ARM 17.8.613 Christmas Tree Waste Open Burning Permits ARM 17.8.614 Commercial Film Production Open Burning Permits ARM 17.8.615 Firefighter Training	These are procedural rules that have specific requirements that may become relevant to a major source during the permit span. With respect to ARM 17.8.615, ExxonMobil maintains a fire training area where firefighter training is conducted frequently during the year. ExxonMobil has a fire training permit filed with the county to conduct such training.
40 CFR 60, Subpart A - General Provisions 40 CFR 61, Subpart A - General Provisions 40 CFR 63, Subpart A - General Provisions	These federal regulations consist of an applicability statement. These regulations may not be applicable to the source at this time; however, these regulations may become applicable during the life of the permit.

B. NSPS Standards

The following NSPS standards are not applicable to the ExxonMobil Refinery for the reasons identified in the table below.

Applicable Requirement	Reason Not Applicable
40 CFR 60, Subpart UU Standard of Performance for Asphalt Roofing Manufacture	These standards are not applicable because potentially affected facilities were constructed prior to the proposal date of the regulation.
40 CFR 60, Subpart VV Standard of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry	This requirement is not applicable because ExxonMobil does not operate affected facilities.
40 CFR 60, Subpart XX Standard of Performance for Bulk Gasoline Terminals	These standards are not applicable to this permit because ExxonMobil Refinery is permitted separately from the bulk terminal (although they are considered to be one source for the purposes of New Source Review permitting). However, it is applicable to the ExxonMobil Bulk Terminal, permitted under preconstruction Permit #2967-00.
40 CFR 60, Subpart QQQ Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems	These standards are not applicable because affected facilities have not been constructed, modified, or reconstructed since May 4, 1987.

C. NESHAP Standards

The following NESHAP standards are not applicable to the ExxonMobil Refinery for the reasons identified in the table below.

Applicable Requirement	Reason Not Applicable
40 CFR 61, Subpart Y National Emission Standard for Benzene Emissions From Benzene Storage Vessels	These standards are not applicable because ExxonMobil has no benzene storage.
40 CFR 61, Subpart BB National Emission Standard for Benzene Emissions From Benzene Transfer Operations	These standards are not applicable because ExxonMobil has no benzene transfer facilities.

D. MACT Standards

The following MACT standards are not applicable to the ExxonMobil Refinery for the reasons identified in the table below.

Applicable Requirement	Reason Not Applicable
40 CFR 63, Subpart H National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks	The requirement is not applicable because the refinery is regulated under 40 CFR 63 Subpart CC.
40 CFR 63, Subpart Q National Emission Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers	These standards are not applicable. ExxonMobil does not operate industrial process cooling towers that use chromium-based treatment of chemicals.
40 CFR 63, Subpart R National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations)	These standards are not applicable to this permit because ExxonMobil Refinery is permitted separately from the bulk terminal (although they are considered to be one source for the purposes of New Source Review permitting). However, it is applicable to the ExxonMobil Bulk Terminal, permitted under preconstruction Permit #2967-00.

SECTION V. FUTURE PERMIT CONSIDERATIONS

A. MACT Standards

As of November 3, 2003, the ExxonMobil refinery is currently subject to Subpart CC- Petroleum Refineries and will be subject to Subpart UUU – Petroleum Refineries Catalytic Cracking, Catalytic Reforming & Sulfur Plant Units (promulgated April 11, 2002). The following new/proposed MACT standards are potentially applicable to ExxonMobil: Subpart YYYY – Combustion Turbines (promulgated August 29, 2003); Subpart DDDDD – Industrial, Commercial, and Institutional Boilers and Process Heaters (proposed January 13, 2003); Subpart ZZZZ – Reciprocating Internal Combustion Engines (proposed December 19, 2002); Subpart EEEE – Organic Liquids Distribution (promulgated August 25, 2003); and Subpart GGGGG – Site Remediation (promulgated October 8, 2003).

B. NESHAP Standards

As of April 29, 2004, the only NESHAP standards that the ExxonMobil refinery is currently subject to include Subpart M - Asbestos and Subpart FF - Benzene Waste Operations. The Department is unaware of any proposed or pending NESHAP standard that may be applicable to ExxonMobil.

C. NSPS Standards

As of November 3, 2003, the only NSPS standards that the ExxonMobil refinery is currently subject to include Subparts J, Kb, and GGG. The Department is unaware of any proposed or pending NSPS standard that may be applicable to ExxonMobil.

D. Risk Management Plan

Facilities exceeding the threshold quantities of regulated substances in a process were required to comply with 40 CFR 68 requirements no later than June 21, 1999. Facilities must comply within 3 years after the date on which a regulated substance is first listed under 40 CFR 68.130, or the date on which a regulated substance is first present in more than a threshold quantity in a process; whichever is later.

Because ExxonMobil exceeds the minimum threshold quantity for several regulated substances listed under 40 CFR 68.115, ExxonMobil was required to submit a Risk Management Plan to EPA by June 21, 1999. ExxonMobil submitted the plan to EPA on June 21, 1999.

The refinery has several regulated flammables such as propane, butane, etc. In addition, the refinery uses and/or processes anhydrous ammonia, aqueous ammonia (>20%), hydrofluoric (HF) acid and hydrogen sulfide, which are also regulated substances. Although the anhydrous ammonia, aqueous ammonia (>20%), and hydrogen sulfide are present in amounts less than the threshold quantities, ExxonMobil treats them in the same way by applying the accidental release prevention and the emergency response programs.

SECTION VI. OTHER CONSIDERATIONS

The Department has reviewed the refinery and ExxonMobil's bulk marketing terminal and has determined that for the purposes of New Source Review permitting, these facilities are one source. The refinery and the bulk marketing terminal are contiguous and adjacent, under common ownership and control and the terminal is a support facility to the refinery. Because the facilities meet these criteria, they meet the definition of source and will be considered one source under the requirements of ARM 17.8.749 and ARM 17.8.801(7). The emissions from both facilities will need to be considered when either facility makes a change.