MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY
OPERATING PERMIT TECHNICAL REVIEW DOCUMENT

Air, Energy & Mining Division – Air Quality Bureau
1520 E. Sixth Avenue
P.O. Box 200901
Helena, Montana 59620-0901

ExxonMobil Fuels & Lubricants Company
Billings Refinery
(Referred to as ExxonMobil Billings Refinery or ExxonMobil)
S½ of Section 24 and N½ of Section 25, Township 1 North,
Range 25 East, Yellowstone County
700 ExxonMobil 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	
Continuous Opacity Monitoring System (COMS) Required	X		FCC carbon monoxide (CO) Boiler Stack, Coker CO Boiler Stack
Continuous Emission Monitoring System (CEMS) Required	X		CO, Hydrogen sulfide (H_2S), sulfur dioxide (SO_2), and oxides of nitrogen (NO_x)
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 and FIP

Applicable Air Quality Programs			
ARM Subchapter 7 Montana Air Quality Permits (MAQP)	X		MAQP #1564
New Source Performance Standards (NSPS)	X		Subparts A, GGG, GGGa, J, Ja, Kb, and IIII
National Emission Standards for Hazardous Air Pollutants (NESHAPS)	X		Subparts J, V, M, and FF
Maximum Achievable Control Technology (MACT)	X		Subparts A, CC, UUU, EEEE ZZZZ and DDDDD
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	
Compliance Assurance Monitoring (CAM)	X		Appendix F
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 emission 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 were based on information provided in the original application submitted by 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; significant modification applications submitted on February 13, 2002, October 22, 2003, April 9, 2004, February 9, 2005, September 22, 2005, and October 5, 2005; Administrative Amendment requests dated January 11, 2006, April 5, 2006, and February 9, 2007; the Title V renewal application submitted June 6, 2006; Administrative Amendment requests dated February 28, 2008, April 15, 2008, June 19, 2008, and November 24, 2008; a significant modification application submitted on April 20, 2009; a significant modification application submitted on July 6, 2009, with additional information submitted on August 11, 2009, and December 24, 2009; a significant modification application submitted on June 1, 2010; and a significant modification application submitted on April 28, 2011, with additional information submitted on June 24, 2011, and August 17, 2011; correspondence received on April 16, 2012; correspondence and an Administrative Amendment requests received on August 6, 2012, September 28, 2012, and January 28, 2013, the modification request received November 27, 2013; a renewal application received July 23, 2013; modification request received February 4, 2015; a change in Responsible Official notice received on August 1, 2016; notice of update of the contact person from Joe Lierow to Joshua McIntosh and name change from ExxonMobil Refining & Supply Company to ExxonMobil Fuels & Lubricants Company received on April 5, 2018, the renewal application received March 27, 2020, the administrative amendments received August 20, 2021, April 15, 2022, and June 23, 2022.

B. Facility Location

The ExxonMobil Billings Refinery is located at 700 ExxonMobil 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). ExxonMobil 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 **Montana Air Quality Permit (MAQP) #1564A2** to support the Yellowstone Energy Limited Partnership (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(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 pounds per million British thermal units (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 Coker Carbon Monoxide 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 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 oxides of nitrogen (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 has been changed from 1.1 to 0.96 lbs. of sulfur-in-fuel per million Btu's 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 information attached to MAQP #1564-03 which 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 Department of Environmental Quality (DEQ) 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. DEQ 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, DEQ believed the increased stack height may be necessary to address concerns with the current SIP and, therefore, may not be 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/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 **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 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 **MAQP #1564-06** to construct the Fluid Catalytic Cracking (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 DEQ 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, DEQ 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, 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 40 CFR 60, 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 **MAQP #1564-08** to bring the permit closer to the requirements of the June 12, 1998, Stipulation between Exxon, DEQ, and the Board of Environmental Review. The proposed changes reduced the reporting and recordkeeping burden for both Exxon and DEQ, updated the permit with current rule references, and consolidated all the previously issued permits to Exxon in MAQP #1564-08. The specific changes to the permit and consolidated permits are outlined in the permit analysis section of MAQP #1564-08.

On August 21, 2000, Exxon submitted a permit application to DEQ, 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 million British thermal units per hour (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. **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, DEQ 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 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, DEQ 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. **MAQP #1564-11** replaced MAQP #1564-09.

On May 16, 2001, DEQ 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 MAQP #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, 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 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, DEQ 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. **MAQP #1564-12** replaced MAQP #1564-11.

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

On February 13, 2002, DEQ 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 FCC Unit, 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 PSD of Air Quality SO_2 significance levels. In addition, a contemporaneous decrease in 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 several 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 FCC Unit 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 backpressure 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).

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

Operating Permit #OP1564-01 incorporated the changes made to the MAQPs #1564-09 and #1564-13. As mentioned above, MAQP #1564-10 was not issued. MAQPs #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 Operating Permit #OP1564-00, DEQ 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. Operating Permit **#**OP1564-01 was issued final and effective on July 20, 2004 and replaced Operating Permit #OP1564-00.

On October 22, 2003, DEQ received a 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, DEQ 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, DEQ 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 FCC Unit, 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, DEQ 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 FCC Unit, Alkylation Unit, Powerformer Unit, and Hydrocracker Unit. Crude oil throughput did not increase because 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 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, DEQ 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 to create more PMA from a historical production rate of 300 – 600 barrels per day, to 5000 barrels per day PMA, and to allow PMA loading of railcars. In addition, on October 19, 2005, DEQ 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, DEQ 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, DEQ determined that the application was complete on February 17, 2006. **MAQP #1564-18** replaced MAQP #1564-17.

DEQ received two de minimis notifications and two administrative amendment requests from ExxonMobil. The administrative amendment was issued May 8, 2007, in response to these four requests:

- 12/22/05 – Catalytic Hydrotreater Unit – Billings (CHUB-Amine) and 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/CO boiler and treat Sour Water Stripper (SWS) overhead to meet Consent Decree requirements (no permit changes required).

Section II of the permit was also reorganized, and extraneous permit conditions were eliminated. **MAQP #1564-19** replaced MAQP #1564-18.

On June 6, 2006, DEQ received an application for the renewal of Title V Operating Permit #OP1564-01. The application was deemed administratively complete on July 6, 2006, and technically complete on August 7, 2006. Operating Permit #OP1564-02 incorporates all applicable source changes since the issuance of Operating Permit #OP1564-01, including:

- Consolidation of all refinery fuel gas combustion requirements into a new EU00;
- Addition of a Refinery-wide fugitive emitting unit EU17;
- Elimination of all emitting units that have no applicable requirements, other than facility-wide applicable requirements (EU02, EU05, EU-06, EU07, EU08, EU10, EU11, EU12, EU13, EU16);
- Addition of a new emergency stationary engine EU18; and
- Inclusion of all Consent Decree requirements.

On December 3, 2007, Exxon appealed Operating Permit #OP1564-02 based on the inclusion of the entire Consent Decree CV-05-C-5809. DEQ included the Consent Decree because it considered the Consent Decree requirements as relevant terms and conditions required to be included in the Title V Operating Permit. The following language (and changes to the permit as described below) satisfy both Exxon and DEQ with respect to inclusion of Consent Decree requirement into the Title V Operating Permit. Exxon will continue to pursue the necessary permitting action as necessary to comply with the requirements of the Consent Decree.

ExxonMobil has entered into a Consent Decree (United States et al v. Exxon Mobil Corp., CV-05-C-5809 (N.D. Ill. Dec. 13, 2005)). Certain consent decree emission limits, standards, and schedules have been incorporated as applicable requirements into the appropriate sections of this permit. Other consent decree requirements, *including program enhancements, are not required by the Consent Decree to be incorporated into this permit as permit conditions and are thereby not included as applicable requirements in this permit.* These terms and conditions may only be enforced by the State of Montana and the United States Environmental Protection Agency pursuant to the provisions of the Consent Decree. This summary is intended for convenient reference only and the actual language of the Consent Decree governs the terms and conditions that are enforceable through the Consent Decree.

Operating Permit #OP1564-02 replaced Operating Permit #OP1564-01.

DEQ received three de minimis notifications and one administrative amendment requests from ExxonMobil. The current administrative amendment is in response to each of these requests described more thoroughly below.

On February 28, 2008, a de minimis notification was received proposing process modifications 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) 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, 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 if 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 if 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.

Operating Permit #OP1564-03 replaced Operating Permit #OP1564-02, incorporating the applicable changes associated with permit action MAQP #1564-20, primarily the addition of language signifying modified or the potential to modify Consent Decree deadlines as negotiated by ExxonMobil.

On April 17, 2009, DEQ received a request from ExxonMobil to amend (via administrative amendment) MAQP #1564-20 and modify Operating Permit #OP1564-02 with language that states ExxonMobil will control NOx emissions from F-700 with ULNBs as defined in the Consent Decree. The Operating Permit was assigned **Operating Permit #OP1564-04**; however, as explained below, this permit action was rolled into the permit action that followed. **Operating Permit #OP1564-04** was not issued.

On July 6, 2009 (with additional information received on August 11, 2009), DEQ received a request from ExxonMobil to modify their current permit 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 NO_x reduction strategy as required by the US EPA CD (United States *et al*. v. Exxon Mobil Corporation *et al*., dated December 13, 2005).

In addition to making the requested change, DEQ 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, DEQ 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 the existing B-8 boiler.

On December 24, 2009, DEQ received an Application for an Air Quality Permit Modification from ExxonMobil to incorporate modifications to MAQP #1564-21. The requested changes include 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.

To meet requirements outlined within the EPA CD, 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. To recover this lost FCCU capacity, the proposed project is to install a new, larger C-310. In April 2009, a de minimis request was approved for a modification to this unit. ExxonMobil has changed the scope of the project to install a new unit, which is included in this permit action. **MAQP #1564-22** replaced MAQP #1564-21.
The application associated with the decommissioning of the existing B-8 boiler as part of a NO_x reduction strategy outlined in the Consent Decree was deemed substantively and technically complete on December 24, 2009.

The action (ULNBs on F-700) associated with the application for Operating Permit #OP1564-04 was combined with Operating Permit #OP1564-05. Therefore, Operating Permit #OP1564-04 was never issued.

Operating Permit #1564-05 incorporated the modifications necessary because of decommissioning of the existing B-8 boiler and addition of ULNBs on F-700. In addition to making the requested changes, DEQ 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. **Operating Permit #1564-05** replaced Operating Permit #OP1564-03.

On May 17, 2010, DEQ received a request from ExxonMobil to administratively amend MAQP #1564-22 and on June 1, 2010, DEQ received a request from ExxonMobil to incorporate a significant modification to their operating permit (#OP1564-05). The amendment and significant modification requests were submitted to incorporate into each permit, applicable requirements contained in paragraphs 70, 71, and 73 of the Consent Decree 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 as outlined. **MAQP #1564-23** was issued on August 5, 2010 and replaced MAQP #1564-22. **Operating Permit #OP1564-06** was issued on February 12, 2011 and replaced Operating Permit #OP1564-05.

On April 29, 2011, DEQ received an application for concurrent modifications to MAQP #1564-23 and Title V operating permit #OP1564-06 from ExxonMobil to incorporate several different portable diesel engines certified to EPA Tier 3 emission standards into these permits. The application included proposed limits on annual hours of operation for some of the engines to keep the combined emissions from the permitting action below any NSR/PSD major source modification significant emission rate (SER) thresholds. DEQ 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 and that ExxonMobil must provide compliance, recordkeeping, and reporting methods for a Title V modification. ExxonMobil responded with a letter received June 29, 2011, that addressed the issues presented in the Incompleteness Letter. The engines and operating conditions were as follows:

- Project #1: Two portable emergency backup diesel engines not to exceed 500-hp each and limited to 1,500 hours per year each that is 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: 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: 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. To maximize operational flexibility, ExxonMobil was limited 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 was 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.

ExxonMobil submitted comments on the draft MAQP #1564-24 requesting that all permit conditions referencing the temporary B-8 boiler be removed from the MAQP and operating permit. ExxonMobil stated that a temporary B-8 boiler that was permitted in MAQP #1564-21 as part of the decommissioning and replacement project for this unit was never constructed or operated. Therefore, the use of the temporary B-8 is not needed and could be eliminated from the permits. The replacement B-8 boiler commenced operation on July 31, 2010.

On October 4, 2011, DEQ sent a letter to ExxonMobil describing that periodic NO_x emissions reporting and NO_x CEMS performance reporting from the FCCU COB are not being routinely reported similar to all other refinery CEMS. The NO_x emission limits and CEMS installation is a Consent Decree requirement and the MAQP and Title V operating permit contain the appropriate NO_x emission limits and monitoring requirements. However, there were no requirements prior to this permit action to report the NO_x emissions performance and NO_x CEMS performance such as monitor downtime and excess emissions reporting. Unlike the other pollutant CEMS operating on the FCCU COB, there are no applicable federal regulations (e.g. Subpart J) that address periodic NO_x emissions monitoring and CEMS performance reporting. The letter requested that ExxonMobil amend their MAQP and Title V operating permit to include periodic reporting of the NO_x emissions performance and CEMS performance to properly document compliance with the NO_x emission limits. On November 3, 2011, ExxonMobil submitted correspondence to DEQ requesting that the MAQP and Title V operating permit be amended to include periodic NO_x emissions and CEMS performance reporting for the FCCU COB.

This permit action incorporated these engines and conditions, updated the B-8 boiler information, and established recordkeeping and reporting requirements for the FCCU COB NO_x emissions and CEMS performance. **MAQP #1564-24** was issued on September 13, 2011 and replaced MAQP #1564-23. **Operating Permit #OP1564-07** was final and effective on February 28, 2012, and replaced Operating Permit #OP1564-06.

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

To provide background information, on December 24, 2009, DEQ 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 DEQ 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.

On August 6, 2012, DEQ received correspondence from ExxonMobil requesting that DEQ amend the MAQP and Title V operating permit 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. **MAQP #1564-26** replaces MAQP #1564-25.

On April 16, 2012, DEQ received the semi-annual monitoring report for the period September 1, 2011 through February 29, 2012. Included in that report, was a notification of a change in Responsible Official as of April 1, 2012 to Monica M. Mainland, Refinery Manager.

On August 6, 2012, DEQ received two items of correspondence from ExxonMobil. One was the previously mentioned request that DEQ amend the MAQP and Title V operating permit to change the emitting unit ID and description of the portable diesel-fired air compressor engine SE8. The other served as notification of a proposed change in operations that does not require a revision to Title V Operating Permit #OP1564-07.
ExxonMobil proposed to subsume and streamline the sour water feed monitoring requirement from Section III.C.8 of #OP1564-07 with the monitoring and compliance demonstration associated with the NSPS Subpart J requirement in Section III.F.10. Operating Permit

#OP1564-07 required that ExxonMobil comply with a SIP-derived sampling requirement on the sour water stream for determining H_2S content when a sour water stripper overhead (SWSOH) stream is being burned in the F-1 Crude Furnace or in the flare. A consent decree required ExxonMobil to apply the NSPS Subpart J H_2S control requirements at all times for this SWSOH gas stream. ExxonMobil monitors compliance with NSPS Subpart J with an Alternative Monitoring Plan (AMP) that has been approved by the United States Environmental Protection Agency (EPA). ExxonMobil's implementation of the NSPS Subpart J requirements eliminates the emission of SO_2 from the combustion of this SWSOH gas stream; therefore, the SIP-required sampling for H_2S content is unnecessary for determining compliance with the applicable SO_2 emission limit from the combustion of this SWSOH gas stream during the specified operating scenario.

DEQ reviewed the notification and concurred that ExxonMobil's implementation of the NSPS Subpart J requirements renders the SIP-required sampling for H_2S content for the SWSOH gas stream unnecessary for demonstrating compliance with the applicable SO_2 emission limit. Monitoring compliance with NSPS Subpart J via the EPA-approved AMP can be considered a surrogate monitoring demonstration for the sampling requirements of Section III.C.8 of #OP1564-07. This change in operations could occur without a revision to the Title V Operation Permit #OP1564-07 in accordance with ARM 17.8.1224 because the change did not require a modification of ExxonMobil's current MAQP, did not result in any change in emissions from the source, maintained permit terms that are necessary for enforcing applicable emission limitations, and ExxonMobil provided notice to both EPA Region VIII and DEQ. For consistency and clarity, DEQ recommended that ExxonMobil request for this determination to be incorporated into Section IV.D of their Title V Operating Permit which summarizes other subsumed and streamlined requirements that are applicable to the facility. DEQ received this request from ExxonMobil on September 28, 2012.

This permitting action was an administrative permit action that updated the Responsible Official for the facility, changed the emitting unit ID and description of the portable diesel-fired air compressor engine SE8, and updated the monitoring requirements for when the SWSOH is being burned in the F-1 Crude Furnace or flare. **Operating Permit #OP1564-08** replaced Operating Permit #OP1564-07.

An administrative action added a portable, 100-brake horsepower, Tier 3, diesel-fired engine to be used for emergency backup and to assist with on-going remediation efforts. This action added the emitting unit ID (SE13) including a description of the portable diesel-fired engine, and updated permit language. **Operating Permit #OP1564-09** replaced Operating Permit #OP1564-08.

On November 27, 2013, DEQ received a request to modify MAQP #1564-27 and OP1564-09. The action permitted an increase in maximum allowable horsepower of two diesel-fired engines utilized for air compression from 500 brake horsepower to 600 brake horsepower. These engines are emergency backup units to existing equipment. These engines were permitted in a flexible manner so any engine that meets the designated emissions standards and does not exceed the maximum rated horsepower assigned can be utilized, including swapping out of engines as necessary. The engines are designated the SE7 and SE8 engines. Because the renewal application, assigned application #OP1564-10, was not yet issued, this action was assigned #OP1564-11, and the permitting sequence skipped from #OP1564-09 to #OP1564-11. **Operating Permit #OP1564-11** replaced Operating Permit #OP1564-09. **MAQP #1564-28** replaced MAQP #1564-27.

On May 27, 2014, DEQ received an MAQP administrative amendment request from ExxonMobil to remove references to consent decree regulatory references. ExxonMobil requested that regulatory authority reside outside of the consent decree, through ARM 17.8.749. Startup, shutdown, and malfunction (SSM) exclusions, as originally contained in the consent decree, were also requested to be incorporated into the permit, under ARM 17.8.749. DEQ incorporated these requests.

ExxonMobil requested that several New Source Performance Standards (NSPS) and Maximum Achievable Control Technology (MACT) regulations applicable to the refinery be added to the MAQP, including NSPS Kb, IIII, and Dc, and MACT DDDDD, EEEE, and ZZZZ. Other administrative changes included removal of permit conditions allowing Tank 55 to be modified for asphalt service.

ExxonMobil also requested that the UT/C4 emergency generator engine be worded such that flexibility is provided to allow this engine to be swapped out for an engine of equal or smaller horsepower and equivalent emission level/Environmental Protection Agency (EPA) tier rating or better. DEQ has typically provided this kind of flexible permitting to generator engines and incorporated this change into this permit at ExxonMobil's request. **MAQP #1564-29** replaced MAQP #1564-28.

On July 23, 2013 DEQ received from ExxonMobil an operating permit renewal application. The permit action renewed the Title V Operating Permit. Changes and updates included those achieved in MAQP #1564-29, and various updates to NSPS and MACT applicability. **Operating Permit #OP1564-10** replaced Operating Permit #OP1564-11.

On April 28, 2015 DEQ received from ExxonMobil an administrative amendment request. ExxonMobil requested that Condition III.F.9 be returned to the original language of the consent decree, by including the option to re-route sour water stripper overhead gas. In addition, several other administrative changes were requested to the formatting and content of conditions tables. Also, ExxonMobil requested applicability of 40 CFR Part 60, Appendix F, Procedure 3, to the COMs required in Section III.F be noted. This action was assigned Operating Permit **#OP1564-13**, which replaced Operating Permit #OP1564-10. Operating Permit #OP1564-12 was assigned to a modification action issued at a later date.

On February 4, 2015, DEQ received from ExxonMobil an application for modification of the MAQP in regard to the B-8 Boiler, and for addition of a new 600 horsepower portable diesel fired engine. MAQP #1564-30 permitted these changes. This action incorporated the conditions of MAQP #1564-30 into the Title V. **Title V Operating Permit #OP1564-12** replaced Title V Operating Permit #OP1564-13.

On August 1, 2016, DEQ received from ExxonMobil a letter notifying DEQ of a change in responsible official, including signature of the outgoing responsible official, and signature of incoming responsible official. DEQ took Administrative Action on the Title V permit to update the responsible official noted in the permit. **Title V Operating Permit #OP1564-14** replaced #OP1564-12.

On October 20, 2016, DEQ received from ExxonMobil a minor modification request to update the Title V permit to reflect the compliance extension granted for new miscellaneous maintenance process vent requirements in MACT CC. ExxonMobil has need for construction of at least 55 maintenance vent connections to the existing or a new flare header. As such, an extension was determined appropriate to allow for appropriate planning time including determination and request of financial needs, purchasing including lead time requirements, construction and development of operating procedures, and commissioning. While new MACT requirements are often provided a 3-year timeframe for affected sources to comply, in this case, less time was provided by the rule. Language reflecting the extension was added as necessary in Section III.G. of the permit. **Operating Permit #OP1564-15** replaced #OP1564-14.

On April 5, 2018, DEQ received from ExxonMobil a request to update the contact person for this facility, as well as the facility name. The current permit action updates the facility contact from Joe Lierow to Joshua McIntosh. Additionally, the name is changed from ExxonMobil Refining & Supply Company to ExxonMobil Fuels & Lubricants Company. **Operating Permit #OP1564-16** replaces #OP1564-15.

On March 27, 2020, DEQ received from ExxonMobil a renewal application. The permit action renewed the Title V permit for another 5-year term. Some streamlining between federal implementation plan requirements and state control plan requirements as summarized in Section IV.D was accepted in this action, with federal implementation plan requirements combined with other state and federal requirements, subsuming certain state control plan requirements. Other streamlining efforts included recognizing that the generally applicable opacity requirements to the flares can be subsumed. Other changes were largely administrative in nature, clarifying or providing specificity to rule applicability. The facility contact was also updated. **Operating Permit #OP1564-17** replaced #OP1564-16.

On August 20, 2021, DEQ received a request from ExxonMobil to incorporate emissions limits on the Fluid Catalytic Cracking Unit into the MAQP and Title V. The limits reflect an Environmental Protection Agency (EPA) determination of a final SO_2 limit as was required by a consent decree. **MAQP#1564-35** replaced MAQP #1564-34, and **Operating Permit #OP1564-18** replaces #OP1564-17.

On April 15, 2022, DEQ received notification from ExxonMobil of a change in responsible official, including signature of the outgoing responsible official, and signature of incoming responsible official. DEQ took Administrative Action on the Title V permit to update the responsible official noted in the permit. **Title V Operating Permit #OP1564-19** replaced #OP1564-18.

D. Current Permit Action

On June 23, 2022, DEQ received an administrative amendment request from ExxonMobil for the removal of reference to United States, et al. v. ExxonMobil Corporation, et. al, Consent Decree requirements within the MAQP and Title V Operating Permit. **MAQP#1564-36** replaced MAQP #1564-35 and **Title V Operating Permit #OP1564-20** replaces #OP1564-19.

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, DEQ is required to complete a Taking and Damaging Checklist. As required by 2-10-101 through 2-10-105, MCA, DEQ conducted the following private property taking and damaging assessment.

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

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

F. Compliance Designation

On August 18, 2020, DEQ conducted an inspection and observed monitoring equipment for several permitted emitting units. Based upon the site visit, the facility appeared to be in compliance with the conditions and limitations of the air quality permits on the day of the inspection.

On September 8, 2020, DEQ conducted an inspection and reviewed data and processes for emitting unit shut down and startup. Based upon the site visit, the facility appeared to be in compliance with the conditions and limitations of the air quality permits on the day of the inspection.

A full compliance evaluation of ExxonMobil Refinery was conducted on September 17, 2020 ExxonMobil was found to be in compliance with the limits and conditions of MAQP #1564-33 and Title V Operating Permit #OP1564-16 at the time of the inspection.

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. Fluid Catalytic Cracking Unit
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
9. Catalytic Hydrotreater Unit – Billings (CHUB Unit)

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 Montana Sulphur & Chemical Company (MSCC). MSCC has an Amine unit to treat the sour fuel gas and return the sweet refinery fuel gas to ExxonMobil.

The refinery and the adjacent ExxonMobil bulk terminal are considered one facility for the purpose of any permitting completed in accordance with the New Source Review Program. In addition, according to EPA and Department interpretations, ExxonMobil's bulk terminal is considered a "support facility" for the refinery and is therefore part of a Title V major source. At the request of the company, the bulk terminal will be permitted separately under the Title V operating permit program.

B. Emission Units and Pollution Control Device Identification

EU00: RFG – including 12 heaters & boilers not otherwise listed

This emitting unit incorporates all of the facility-wide refinery fuel gas requirements (including 40 CFR 60, Subpart J limitations, and requirements for monitoring, testing, recordkeeping and reporting). This emitting unit also includes the facility-wide Stipulation SO_2 limitations. Compliance is demonstrated for the 40 CFR, Subpart J requirements through use of a H_2S CEMS on the refinery fuel gas (RFG) header. Compliance is demonstrated for the lb/hr Stipulation limitations through use of an RFG fuel gas flow meter in addition to the H_2S CEMS.

<u>EU1b: F-3 Heater Stack</u>. This unit is a process heater that heats crude for the oil fractionation process.
<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.
<u>EU3b: F-202 - Heater Stack</u>. This unit is a process furnace that super heats used steam in the fluid coking process.
<u>EU4a: F-700 Heater Stack</u>. This unit is a process heater that heats naphtha for the reforming process.
<u>EU5a: F-402 Heater Stack</u>. 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.

EU7a: F-201 Heater Stack. This unit is a process heater that heats distillates and hydrogen for the desulfurization process.
EU11a: F-651 Heater Stack. This unit is a process heater that heats feedstock for the hydrocracking process.
EU12a: F-551 Heater Stack. This unit is a gas-fired, steam-reforming heater that contains a catalyst and manufactures hydrogen.
EU13: B-8 Backup Boiler
EU14b: F-10 Stack – Heater. This unit is a gas-fired storage tank heater which heats circulating oil. This unit fires only sweetened fuel.
EU16a: F-1201 Heater Stack. This unit is a process heater in support of the low sulfur motor gasoline process. This stack is required to have ultra-low NO_x burners.
EU03a: Coker CO Boiler (KCOB) and EU09a: FCCU CO Boiler (CCOB) are included under the RFG requirements of this section but are also regulated under individual emitting units.

EU01: Crude – Atmospheric Pipe Still (APS) and Vacuum Pipe Still (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 APS fractionating tower and the heaviest molecules at the bottom of the tower. The heavy "bottoms" from the first fractionation tower (APS) are further fractionated in a vacuum tower (VPS).

EU1a: F-2 Crude Vacuum Heater (F-1 Crude Furnace/ F-401 Vacuum Heater). This unit is a process heater that heats crude and reduced crude oil for the fractionation process.
EU1c: D-4 Drum Atmospheric Stack. 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 EU was eliminated since the heaters are now included under EU00.*

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. 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.
EU3c: Coker Process Gas Vent. Collection of Group I Miscellaneous Process Vents.

EU04: Catalytic Reforming (POFO – Powerforming) Unit

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

EU05: Alky/Splitter/Deethanizer/Diene - Alkylation Unit, Alky Feed Treater, Rerun of Alkylate for Avgas – *this EU was eliminated since the heaters are now included under EU00.*

EU06: Treater - Cat Naphtha Caustic Treater (Merox Unit) after Cat Cracker – *this EU was eliminated since fugitive leak requirements under 40 CFR 63, Subpart CC are now included under a new EU17.*

EU07: HF#1 - *this EU was eliminated since the heaters are now included under EU00.*

EU08: DEC2 - Deethanizer Unit - *this EU was eliminated since fugitive leak requirements under 40 CFR 63, Subpart CC are now included under a new EU17. The Deethanizer is now included under EU05.*

EU09: FCCU - Catalytic 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.

> <u>EU9a: CCOB - FCC CO Boiler</u>. This unit is a steam boiler, which may burn catalytic cracking process gases in addition to supplemental fuels. This stack has both an opacity monitor and an SO_2 CEMS.
> <u>EU9b: CCOB Bypass.</u>

EU10: ULEB/SLEB - Unsaturated Light Ends Unit, Saturated Light Ends Unit, Sour Water Strippers, Gas Compression - *this EU was eliminated since fugitive leak requirements under 40 CFR 63, Subpart CC are now included under a new EU17*

EU11: HCBL - Hydrocracking Unit - *this EU was eliminated since the heaters are now included under EU00.*

EU12: H_2 Plant/HRUB - H_2 Plant, H_2 Upgrade (Recovery) Facility, MDU Replacement - *this EU was eliminated since the heaters are now included under EU00.*

EU13: Utilities - Air Compressors/Dryers, Boiler Feed Water - *this EU was eliminated since the boilers are now included under EU00.*

EU14: OM&U - Oil Movements & Utilities
This unit consists of the flare system

> <u>EU14a: Flare and Turnaround Flare</u>. 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.
> <u>EU14c: Flare Seal Drum</u>. This unit is a Group I Miscellaneous Process Vent.

EU15: OM&S - Oil Movements & Shipping

This unit includes petroleum storage tank farms and the PMA 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 EU was eliminated since fugitive leak requirements under 40 CFR 63, Subpart CC are now included under a new EU17*

EU17: Refinery-Wide Fugitive Emissions

This new unit includes all VOC, HAPs and benzene equipment leaks throughout the facility.

EU18 – Emergency/Backup Stationary and Portable Engines

<u>EU18a: SE1-SE14, IEU6a & IEU6b</u>: 14 or more diesel and 2 gasoline engines. Units SE1 through SE11, SE13, and SE14 are individual diesel-fired engines. SE12 is comprised of one or more diesel-fired engines that are collectively regulated as a single emitting unit. IEU6a and IEU6b are individual gasoline-fired engines.

C. Categorically Insignificant Sources/Activities

Insignificant emission units under Title V are defined under ARM 17.8.1201(22) to mean any emissions unit with the potential to emit less than five tons per year (TPY) of a regulated pollutant, 500 TPY of lead, and 500 lbs/yr of hazardous air pollutants (HAPs); and are not regulated by an applicable requirement, other than a generally applicable requirement.

Appendix A of the Operating Permit lists insignificant emission units at the facility. ExxonMobil is not required to update a list of insignificant emission units outside of renewal or significant modification applications; therefore, the emission units and/or activities may change from those specified in Appendix A.

Emission Unit ID	Description
IEU01	Warehouse building heater
IEU02	Mechanical building heater
IEU03	Operations Control Center building heater
IEU04	FCCU/HCBL Shelter heater
IEU07	Laboratory building heater
IEU08	Laboratory equipment testing emissions
IEU09	Gasoline knock engines (3)
IEU10	Main office building heater
IEU11	Trailer heating units (8)
IEU17	Propane odorant facility
IEU18	Operator's Shelter heater (natural gas-fired residential furnace rated at 10 scfm)
IEU19	MOB HVAC System
IEU20	Diesel tank for MOB Backup Generator
IEU21	Lab Hydrocarbon Waste Tank

SECTION III. PERMIT CONDITIONS

A. Emission Limits and Standards

Emission limits and standards in the Title V operating permit were established by ExxonMobil's MAQP #1564, 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 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 do not require the permit to impose the same level of rigor for all emission units. Furthermore, they do not require extensive testing or monitoring to assure compliance with the applicable requirements for emission 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 emission 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, DEQ 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 DEQ has the authority to require testing if deemed necessary to determine compliance with an emission limit or standard. In addition, the permittee 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, 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 DEQ and Section III.A.1) and biannual Method 5 tests to be performed on the FCC CO boiler and the Coker CO boiler. These testing requirements were established by DEQ's testing policy.

D. Recordkeeping Requirements

The permittee 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 DEQ 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 because 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-annual 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

As an administrative amendment, no public notice is required.

G. Draft Permit Comments

As an administrative amendment, no public comment period is required.

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 Title V Renewal application for Operating Permit #OP1564-10. In addition, that application also requested a permit shield for both the facility and for certain emission units. This section remains in place until the next renewal review.

The following table outlines those requirements that ExxonMobil had identified as non-applicable in Permit Application #OP1564-10 but will not be included in the operating permit as non-applicable. The table includes both the request and reason that DEQ did not provide the shield. This section remains in place until the next renewal review.

Applicable Requirement	**Reason for Not Including**
NSPS	
40 CFR 60 Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units	These are requirements which may be or may become applicable to the source category which is being permitted.
Subpart UU—Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture	These are requirements which may be or may become applicable to the source category which is being permitted.
Subpart VV—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006	Because certain requirements of this NSPS are required through NSPS GGG and MACT CC, DEQ has not provided a shield from this NSPS.
Subpart VVa—Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced	Because certain requirements of this NSPS are required through NSPS GGGa, DEQ has not provided a shield from this NSPS.
Subparts CCC, EEE, MMM – Reserved	These sections are reserved; therefore, a shield is neither necessary nor appropriate.
Subpart QQQ	These are requirements which may be or may become applicable to the source category which is being permitted
Subpart XX and R	The ExxonMobil Billings Refinery contains a separate Title V permit from the ExxonMobil Billings Terminal, however, a shield is not appropriate, as the two facilities are viewed as one source. Applicable requirements are contained in the Terminal Title V permit.

Applicable Requirement	Reason for Not Including
MACT	
40 CFR 63 Subpart F, G, H and I	These are requirements which may have certain provisions required by reference by other relevant standards.
40 CFR 63 Subpart E – Approval of state programs and delegation of federal authorities	These are requirements for EPA or state and local authorities and provide authority to impose specific requirements. A shield is not appropriate.
40 CFR 60 Subpart LLLLL – National Emissions Standards for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing Manufacturing	These are requirements which may be or may become applicable to the source category which is being permitted
40 CFR 63 Subpart AAAAAA - Reserved	These sections are reserved; therefore, a shield is neither necessary nor appropriate.
40 CFR 63 Subpart BBBBBB – National Emissions Standards for Hazardous Air Pollutants: Gasoline Distribution Bulk Terminals, Bulk Plants, and Pipeline Facilities.	The ExxonMobil Billings Refinery contains a separate Title V permit from the ExxonMobil Billings Terminal, however, a shield is not appropriate, as the two facilities are viewed as one source. Applicable requirements are contained in the Terminal Title V permit.
40 CFR 63 Subpart AAAAAAA – National Emissions Standards for Hazardous Air Pollutants: Asphalt Processing and Asphalt Roofing Manufacturing	These are requirements which may be or may become applicable to the source category which is being permitted

The following table outlines those requirements that ExxonMobil had identified as non-applicable on an emitting unit basis in Permit Application #OP1564-10 but will not be included in the operating permit as non-applicable. This section remains in place until the next renewal review.

Emission Unit ID	Rule Citation	Reason for not including
For Tanks other than Tanks #11 and #101	40 CFR 60, Subparts K, Ka, Kb	The definition of the emitting unit is too broad, and these are requirements which may be or may become applicable to the source category which is being permitted.
For all units other than Low Sulfur Mogas.	40 CFR 60, Subpart GGG	The definition of the emitting unit is too broad, and these are requirements which may be or may become applicable to the source category which is being permitted.
EU00 - Process Heaters Other: F-1 and F-401	40 CFR 60, Subparts Db and Dc	This requirement may be or may become applicable to the source category which is being permitted.
Refinery-wide Benzene-containing Wastewater	40 CFR 61.344 Standards: Surface Impoundments	This requirement may be or may become applicable to the source category which is being permitted.

Emission Unit ID	Rule Citation	Reason for not including
Refinery-wide Benzene-containing Wastewater	40 CFR 61.347 Standard: Oil-water separators	This requirement may be or may become applicable to the source category which is being permitted.

B. Streamlined Requirements

Pursuant to ARM 17.8.1212, as of 1/23/09 when Operating Permit #OP1564-02 became final and effective, the federally enforceable standards, monitoring, recordkeeping, reporting and other applicable requirements cited in the following table for the listed source or group of sources are subsumed by the more stringent requirement or by a "hybrid" compliance demonstration scheme. DEQ has determined that compliance with the streamlined requirements listed below and elsewhere in this permit will assure compliance with the substantive provisions of the subsumed requirements.

Emission Unit ID	Subsumed Rule Citation	Streamlined Rule Citation	Reason
Fuel Gas Combustion Devices – • EU00 • EU03a (KCOB) • EU09a (CCOB) • EU14a (Flare and T/A Flare)	ARM 17.8.322(4) Sulfur in Fuel - Liquid and Solid Fuel limited to 1 lb sulfur per million Btu fired.	ARM 17.8.749, ExxonMobil is not capable of combusting solid fuel, and is not allowed to fire fuel oil, except during periods of natural gas curtailment, and except for (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.	Compliance with 40 CFR 60, Subpart J and not firing fuel oil will ensure compliance with the more generous subsumed rule.
Fuel Gas Combustion Devices – • EU00 • EU03a (KCOB) • EU09a (CCOB) • EU14a (Flare and T/A Flare)	ARM 17.8.322(5) Sulfur in Gaseous Fuel – 50 grains/100 cubic feet (1,144 milligrams H_2S/dry standard cubic meter fuel (mg H_2S/dscm fuel)) Refinery-wide block hourly fuel sulfur limit of 0.96 lb/MMBtu fired (13,234 mg H2S/dscm fuel at a minimum RFG HHV of 810 Btu/scf)	40 CFR 60, Subpart J: 230 mg H_2S/dscm fuel (equivalent to 0.10 grains/dscf or ~160 ppmv H_2S @ STP)	The 40 CFR 60, Subpart J fuel sulfur (as H_2S) limit is much more stringent. Compliance with the NSPS limit assures compliance with the subsumed limits.
Fuel Gas Combustion Devices – • EU00 • EU03a (KCOB)	Billings/Laurel SO_2 Control Plan (Exhibit A), Section 6(B)(3)	Hybrid Statement: NSPS Subpart J continuous monitoring (Fuel gas H_2S CEMS – §60.105(a)(4) and §60.13; and flow rate monitoring CEMS –	The RFG H_2S CEMS required by 40 CFR 60, Subpart J meets or exceeds the performance specifications for the

Emission Unit ID	Subsumed Rule Citation	Streamlined Rule Citation	Reason
• EU09a (CCOB)		Billings/Laurel SO_2 Control Plan (Exhibit A), Section 6(B)(8).	Fuel gas H_2S CEMS required by continuous monitoring provisions of the Billings/Laurel SO_2 Control Plan (Exhibit A, Section 6(B)(3). The redundant RFG H_2S CEMS is eliminated.
	Billings/Laurel SO_2 Control Plan (Exhibit A), Section 5 Emissions Testing: §5(B) Annual Source Testing Method 11 or equivalent.	Annual RATA (Method 11)	The annual source testing requirement is not necessary, as the annual RATA (Method 11) meets this requirement.
EU17 – Equipment Leaks Refinery-Wide	40 CFR 60, Subpart GGG; 40 CFR 61, Subparts J and V	40 CFR 63, Subpart CC (Petroleum Refinery MACT Rule)	Process units refinery-wide are subject to equipment and work practice standards, test methods and procedures, monitoring, recordkeeping and reporting requirements for equipment leaks set out in the Petroleum Refinery MACT Rule, which are at least equivalent or more stringent than the equipment leak standards and provisions of NSPS and NESHAPS.
EU15 – Group 1 Storage Vessels (Crude oil, gasoline, and petroleum distillate tanks > 65,000 gallons capacity)	ARM 17.8.324(1) – Hydrocarbon emissions – Petroleum products		All tanks with a storage capacity > 65,000 gallons and storing crude oil, gasoline, or distillates with a vapor pressure of 2.5 psia (17.2kPa) or greater are classified as Group I storage vessels, which are subject to the more stringent Petroleum Refinery MACT Rule.
Fuel Gas Combustion Devices – • EU00	ARM 17.8.322(5) Sulfur in Gaseous Fuel – 50 grains/100 cubic feet (1,144 milligrams	40 CFR 60, Subpart J: 230 mg H_2S/dscm fuel (equivalent to 0.10	The NSPS Subpart J fuel sulfur (as H_2S) limit is much more stringent. Compliance

Emission Unit ID	Subsumed Rule Citation	Streamlined Rule Citation	Reason
• EU03a (KCOB) • EU09a (CCOB) EU14a (Flare and T/A Flare)	H_2S/dry standard cubic meter fuel (mg H_2S/dscm fuel))	grains/dscf or ~160 ppm_{vd} H_2S @ STP)	with the NSPS limit assures compliance with the subsumed limits.
F-1 Crude Furnace or the Flare when combusting SWSOH	Sampling and analysis of the sour water feed to the T-23 sour water stripper tower for H_2S when burning SWSOH in F-1 Crude Furnace or the Flare (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003)	Treatment of the SWS feed with hydrogen peroxide complies with 40 CFR 60, Subpart J (ARM 17.8.340 and 40 CFR 60, Subpart J;)	SWSOH stream qualifies as an inherently low sulfur stream as defined in 40 CFR 60 Subpart J.
EU03 – Coker – Fluid Coker	ExxonMobil may remove the monitors from the KCOB stack whenever Coker process gas is not being exhausted through the stack. However, at any time after initial installation and certification of the monitors ExxonMobil exhausts Coker process gas through the KCOB stack, ExxonMobil shall within 48 hours: a. Reinstall the monitors at the same location on the KCOB stack (including probe position in the stack); b. Perform a cylinder gas audit (CGA) or Relative Accuracy Audit (RAA) which meets the requirements and specifications of 40 CFR Part 60, Appendix F; and c. Operate the monitors in accordance with the quality assurance requirements of Section 6 as long as Coker process gas continues to be exhausted through the KCOB stack.	ExxonMobil shall operate and maintain a CEMS to measure SO2 concentrations and a continuous stack flow rate monitor in the Coker CO Boiler. Whenever Coker flue gases are exhausted through the Coker CO Boiler stack, the CEMS and flow rate monitor shall be operational and shall achieve a temporal sampling resolution of at least (1) concentration per minute, calculate an hourly average (as defined in Section (c)(14) of the FIP), meet the CEMS Performance Specifications contained in Section 6(c) and 6(D) of the ExxonMobil 1998 Exhibit, except that a Cylinder Gas Audit (CGA) or a Relative Accuracy Audit (RAA) shall be conducted on the SO2 CEM which meets the requirements of 40 CFR 60 Appendix F, within eight hours of when the Coker unit flue gases begin exhausting through the Coker CO Boiler stack (Federal Implementation Plan for the	The FIP limit is more stringent than the SIP limit.

Emission Unit ID	Subsumed Rule Citation	Streamlined Rule Citation	Reason
	(Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003)	Billings/Laurel Area FR Vol. 73, No. 77, April 21, 2008).	
EU14 – Oil Movements and Utilities, specifically EU14a: Flare – Flare or Turnaround Flare	ExxonMobil shall not allow SO_2 emissions from any flare, unless the emissions are a minor flaring event (150 lb/3-hour period as defined in Exhibit A-1 of the Stipulation), or are the result of startup, shutdown, or a malfunction as defined in ARM 17.8.110 (Board Order signed on June 12, 1998, and subsequent revisions of March 17, 2000, this requirement is "State Only").	The total combined emissions of the SO_2 from the main and turnaround flares shall not exceed 150.0 lbs per 3-hour period (Federal Implementation Plan for the Billings/Laurel Area FR Vol 73, No. 77, April 21, 2008).	The FIP limit is as stringent or more stringent than the corresponding Board Order.
EU14 – Oil Movements & Utilities, specifically EU14a: Flare – Flare or Turnaround Flare	Except for monitor flaring events, ExxonMobil shall minimize SO_2 emissions from flaring. In addition, when flaring of sulfur bearing gases occurs due to a malfunction, ExxonMobil shall take immediate corrective action to correct the malfunction (Board Order signed on June 12, 1998, and subsequent revisions of March 17, 2000; this requirement is "State Only").	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 CFR 60.11(d) (ARM 17.8.749). And ExxonMobil shall conduct a Root Cause Failure Analysis for each acid gas flaring event and hydrocarbon flaring event within 45 days of the end of the event, in accord with the Root Cause Failure	40 CFR 60, Subpart Ja requirements have stricter flare provisions than the Board Order, from flare minimization to investigation.
EU14 – Oil Movements & Utilities (OM&U),	For flaring events in excess of 150 lbs/3-hr period, ExxonMobil shall	ExxonMobil shall conduct a Root Cause Failure Analysis for each acid gas	The FIP provisions focus on investigating and

Emission Unit ID	Subsumed Rule Citation	Streamlined Rule Citation	Reason
specifically, EU14a: Flare – Flare or Turnaround Flare	comply with the reporting requirements identified in Section (3)(A)(5) of Exhibit A-1 of the Stipulation (Appendix E of this permit) (Board Order signed on June 12, 1998, and subsequent revisions of March 17, 2000; this requirement is "State Only").	flaring event and hydrocarbon flaring event within 45 days of the end of the event, in accord with the Root Cause Failure Analysis as prescribed in Appendix H And Section V.E – Prompt Deviation requirements, including malfunction reporting requirements	minimizing flaring overall. In addition, under the FIP, any flaring event in excess of 150 lb/3-hr period is a permit deviation and would have to be reported as such. Also, prompt deviation reporting requirements, including malfunction reporting requirements, apply.

SECTION V. FUTURE PERMIT CONSIDERATIONS

A. MACT and NSPS Standards

DEQ is not aware of any proposed or pending MACT or NSPS standards that may be applicable to ExxonMobil.

B. NESHAP Standards

DEQ is unaware of any proposed or pending NESHAP standards, in addition to those already listed, that may be applicable to ExxonMobil.

C. NSPS Standards

DEQ is unaware of any proposed or pending NSPS standards, in addition to those already listed, that may be applicable to ExxonMobil.

D. Risk Management Plan

If a facility has more than a threshold quantity of a regulated substance in a process, the facility must comply with 40 CFR 68 requirements no later than June 21, 1999; three 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.

E. Compliance Assurance Monitoring (CAM) Plan

An emitting unit located at a Title V facility that meets the following criteria listed in ARM 17.8.1503 is subject to Subchapter 15 and must develop a CAM Plan for that unit:

- The emitting unit is subject to an emission limitation or standard for the applicable regulated air pollutant (other than emission limits or standards proposed after November 15, 1990, since these regulations contain specific monitoring requirements);
- The emitting unit uses a control device to achieve compliance with such limit; and
- The emitting unit has potential pre-control device emissions of the applicable regulated air pollutant that are greater than major source thresholds.

ExxonMobil currently has one emitting unit that meets all the applicability criteria in ARM 17.8.1503: EU03 KCOB (Coker Unit CO Boiler). The unit is required to meet the process weight rule for PM. A multiclone is used for PM control. ExxonMobil uses opacity monitoring as the on-going method of assuring compliance.

F. Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule

On May 7, 2010, EPA published the "light duty vehicle rule" (Docket # EPA-HQ-OAR- 2009-0472, 75 FR 25324) controlling greenhouse gas (GHG) emissions from mobile sources, whereby GHG became a pollutant subject to regulation under the Federal and Montana Clean Air Act(s). On June 3, 2010, EPA promulgated the GHG "Tailoring Rule" (Docket # EPA-HQ-OAR-2009-0517, 75 FR 31514) which modified 40 CFR Parts 51, 52, 70, and 71 to specify which facilities are subject to GHG permitting requirements and when such facilities become subject to regulation for GHG under the PSD and Title V programs.

Under the Tailoring Rule, any PSD action (either a new major stationary source or a major modification at a major stationary source) taken for a pollutant or pollutants other than GHG that was not final prior to January 2, 2011, would be subject to PSD permitting requirements for GHG if the GHG increases associated with that action were at or above 75,000 tons per year (tpy) of carbon dioxide equivalent (CO_2e). Similarly, if such action were taken, any resulting requirements would be subject to inclusion in the Title V Operating Permit. Starting on July 1, 2011, PSD permitting requirements would be triggered for modifications that were determined to be major under PSD based on GHG emissions alone, even if no other pollutant triggered a major modification. In addition, sources that exceed the 100,000 tpy CO_2e threshold under Title V would be required to obtain a Title V Operating Permit if they were not already subject.

The Supreme Court of the United States (SCOTUS), in its Utility Air Regulatory Group v. EPA decision on June 23, 2014, ruled that the Clean Air Act neither compels nor permits EPA to require a source to obtain a PSD or Title V permit on the sole basis of its potential emissions of GHG. SCOTUS also ruled that EPA lacked the authority to tailor the Clean Air Act's unambiguous numerical thresholds of 100 or 250 TPY to accommodate a CO_2e threshold of 100,000 TPY. SCOTUS upheld that EPA reasonably interpreted the Clean Air Act to require sources that would need PSD permits based on their emission of conventional pollutants to comply with BACT for GHG. As such, the Tailoring Rule has been rendered invalid and sources cannot become subject to PSD or Title V regulations based on GHG emissions alone. Sources that must undergo PSD permitting due to pollutant emissions other than GHG may still be required to comply with BACT for GHG emissions.

SECTION VI. OTHER CONSIDERATIONS

DEQ 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.