June 21, 2022

Kim A. Jakub
ExxonMobil Fuels and Lubricants Company
Billings Petroleum Refinery
700 ExxonMobil Road
PO Box 1163
Billings, MT 59103-1163

RE: Final Title V Operating Permit #OP1564-19

Dear Ms. Jakub:

DEQ prepared this Final Operating Permit #OP1564-19, for Exxon Mobil Corporation's Billings Petroleum Refinery, located in the South ½ of Section 24 and North ½ of Section 25, Township 1 North, Range 26 East, in Yellowstone County, Montana.

This permit must be kept at the facility or a DEQ-approved location.

If you have any questions, please contact Troy Burrows, the permit writer, at (406) 444-1452 or by email at troy.burrows@mt.gov.

Sincerely,

Julie A. Merkel	Troy Burrows
Permitting Services Section Supervisor	Air Quality Scientist
Air Quality Bureau	Air Quality Bureau
(406) 444-3626	(406) 444-1452

JM:TMB
Enclosure
cc: Branch Chief, Air Permitting and Monitoring Branch, US EPA Region VIII 8ARD-PM
Carson Coate, US EPA Region VIII, Montana Office
Robert Gallagher, US EPA Region VIII, Montana Office

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

AIR QUALITY OPERATING PERMIT #OP1564-19

Issued to:
Exxon Mobil Corporation
ExxonMobil Fuels & Lubricants Company
Billings Petroleum Refinery
700 ExxonMobil Road
Billings, MT 59101

Final/Effective Date:	**06/21/2022**
Expiration Date:	**09/09/2026**
Complete Renewal Application Due:	**03/09/2026**

Date of Decision:	05/19/2022
Administrative Amendment Application Received:	04/15/2022
Application Deemed Substantively Complete:	04/15/2022
Application Deemed Administratively Complete:	04/15/2022
AFS Number: 030-111-0013A	

Permit Issuance and Appeal Processes: DEQ issues this permit as effective and final on 06/21/2022. This permit must be kept at the facility or a DEQ-approved location (Montana Code Annotated (MCA) Sections 75-2-217 and 218, Administrative Rules of Montana (ARM), ARM Title 17, Chapter 8, Subchapter 12, Operating Permit Program).

Montana Air Quality Operating Permit
Department of Environmental Quality

Terms not otherwise defined in this permit or in the Definitions and Abbreviations Appendix B of this permit have the meaning assigned to them in the referenced regulations. Whenever there are conflicting definitions within this permit, the definition of terms used in ARM 17.8.1201 shall control.

SECTION I. GENERAL INFORMATION

The following general information is provided pursuant to ARM 17.8.1210(1).

Company Name: **ExxonMobil Fuels and Lubricants Company, a division of Exxon Mobil Corporation (or sometimes referred to as "ExxonMobil Billings Refinery" or simply "ExxonMobil")**

Mailing Address: **P.O. Box 1163**

City: **Billings** State: **Montana** Zip: **59103-1163**

Plant Location: **700 ExxonMobil Road**

Responsible Official: **Kim A. Jakub**

Facility Contact Person: **Aly Batt**

Primary SIC Code: **2911**

Nature of Business: **Petroleum Refining**

Description of Process: ExxonMobil Fuels and Lubricants Company (ExxonMobil) operates a petroleum refinery designed to process high sulfur crude oil. The major processing equipment includes:

1. Atmospheric and vacuum crude distillation towers
2. Fluidized Catalytic Cracking Unit (FCCU)
3. Hydrocracker and Hydrogen Plant
4. Fluid Coker
5. Naphtha Fractionator
6. Catalytic Reformer
7. Hydrofluoric Alkylation Unit
8. Three Hydrotreaters for treating the naphtha and distillate streams
9. Catalytic Hydrotreating Unit – Billings (CHUB) [previously referred to as Low Sulfur MoGas Unit]

ExxonMobil does not have a sulfur recovery unit at this refinery. Refinery gases high in Hydrogen Sulfide (H_2S) are piped to an off-site sulfur recovery plant owned and operated by the Montana Sulphur and Chemical Company (MSCC). MSCC extracts sulfur from the sour refinery fuel gas and returns sweetened fuel gas to ExxonMobil. ExxonMobil sends Coker Process Gases to the Yellowstone Energy Limited Partnership (YELP) facility for treatment (combustion) in two boilers, except when YELP is down. The refinery and the bulk terminal are considered one facility for the purpose of any permitting completed in accordance with the New Source Review Program and for Title V permitting threshold determinations, however, the bulk terminal section of the Title V is provided separately under Title V operating permit #OP2967.

SECTION II. SUMMARY OF EMISSION UNITS

The emission units regulated by this permit are the following (ARM 17.8.1211):

Unit ID	Descriptions	Pollution Control Device/Practices
EU00	RFG Combustion Devices EU01b: F-3 Heater EU02a: F-3x Heater EU02b: F-5 Heater EU03a: Coker CO Boiler (also see EU03) EU03b: F-202 Heater EU04a: F-700 Heater EU05a: F-402 Heater EU07a: F-201 Heater EU09a: FCCU CO Boiler (also see EU09) EU11a: F-651 Heater EU12a: F-551 Heater EU13: B-8 Boiler EU14b: F-10 Heater EU16a: F-1201 Heater	H_2S Continuous Emissions Monitoring System (CEMS) on RFG Header, RFG Flow Meter, and flare header. F-700 – Ultra Low NOx Burner (ULNB) FCCU CO Boiler - Selective Catalytic Reduction (SCR) B-8: ULNB and FGR F-1201 – ULNB 40 CFR 63 Subpart DDDDD Tune-ups
EU01	Crude Unit – Atmospheric Pipe Still (APS) and Vacuum Pipe Still (VPS) EU01a: F-2 Crude/Vacuum Heater (F-1 Crude Furnace/F-401 Vacuum Heater) EU01c: D-4 Drum Atmospheric Stack	None None None
EU02	HF #2/3 – Hydrofining Units #2 and #3 – *Eliminated EU (heaters moved to EU00)*	
EU03	Coker – Fluid Coker EU03a: Coker Unit Carbon Monoxide (CO) Boiler (KCOB) EU03c: Coker Group I Miscellaneous Process Vents	YELP/ KCOB, Multiclone, Continuous Opacity Monitoring System (COMS)/Compliance Assurance Monitoring (CAM) Plan, Sulfur Dioxide (SO_2) CEMS, H_2S CEMS on RFG Header (*see EU00*), 40 CFR 63 Subpart DDDDD Tune-ups on Boiler, 40 CFR 63 Subpart CC for miscellaneous process vents
EU04	Catalytic Reforming (Powerforming (POFO)) Unit	40 CFR 63 Subpart UUU
EU05	Alky/Splitter/Deethanizer/Diene – Alkylation Unit, Alky Feed Treater, Rerun of Alkylate for Avgas – *Eliminated EU (heater moved to EU00)*	
EU06	Treater – Cat Naphtha Caustic Treater (Merox Unit) after Cat Cracker – *Eliminated EU (requirements covered by EU17)*	
EU07	HF#1– *Eliminated EU (heater moved to EU00)*	

Unit ID	Descriptions	Pollution Control Device/Practices
EU09	FCCU – Catalytic Cracking Unit EU09a: CCOB (FCCU CO Boiler) EU09b: CCOB – Bypass	Selective Catalytic Reduction (SCR), COMS, SO_2 CEMS, Carbon Monoxide (CO) CEMS, nitrogen oxides (NO_x) CEMS, Sour Water Stripper Overheads (SWSOH) sent to CCOB 40 CFR 60 Subpart J, 40 CFR 63 Subpart UUU
EU10	ULEB/SLEB – Unsaturated Light Ends Unit, Saturated Light Ends Unit, Sour Water Strippers, Gas Compression– *Eliminated EU (requirements covered by EU17)*	
EU11	HCBL – Hydrocracking Unit – *Eliminated EU (heater moved to EU00)*	
EU12	H_2 Plant/HRUB – H_2 Plant, H_2 Upgrade (Recovery) Facility, MDU Replacement – *Eliminated EU (heater moved to EU00)*	
EU13	Utilities – Air Compressors/Dryers, Boiler Feed Water System – *Eliminated EU (boilers moved to EU00)*	
EU14	Oil Movements and Utilities (OM&U) EU14a: Flare – Flare and Turnaround Flare EU14c: Flare Seal Drum	Steam assisted flare, CEMS on RFG Header (*see EU00*), Flare H_2S CEMS, TS CEMS, and Flow Meter
EU15	Oil Movements & Shipping (OM&S)	Group I MACT Controls
EU16	Catalytic Hydrotreater Unit – Billings (CHUB) (or Low Sulfur Mogas) – *Eliminated EU (heater moved to EU00, other requirements covered by EU17)*	
EU17	Refinery-Wide Fugitive Emissions	LDAR
EU18	Emergency/Back Up Portable and Stationary Engines EU18a: SE1–SE14, IEU06a & IEU06b, LK01-04	EPA engine standards

SECTION III. PERMIT CONDITIONS

The following requirements and conditions are applicable to the facility or to specific emission units located at the facility (ARM 17.8.1211, 1212, and 1213).

A. Facility-Wide

Conditions	Rule Citations	Rule Description	Pollutant/Parameters	Limit
A.1	ARM 17.8.105	Testing Requirements	Testing Requirements	-------
A.2	ARM 17.8.106	Source Testing Protocol	Testing, Recordkeeping, and Reporting Requirements	-------
A.3	ARM 17.8.304(1)	Visible Air Contaminants	Opacity	40%
A.4	ARM 17.8.304(2)	Visible Air Contaminants	Opacity	20%
A.5	ARM 17.8.304(3)	Visible Air Contaminants	Opacity	60%
A.6	ARM 17.8.308(1)	Particulate Matter (PM), Airborne	Fugitive – Opacity	20%
A.7	ARM 17.8.308(2)	PM, Airborne	Reasonable Precautions	-------
A.8	ARM 17.8.308(3)	PM, Airborne	Reasonable Precaution, Construction	20%
A.9	ARM 17.8.309	PM, Fuel Burning Equipment	PM	$E = 0.882 * H^{-0.1664}$ or $E = 1.026 * H^{-0.233}$
A.10	ARM 17.8.310	PM, Industrial Processes	PM	$E = 4.10 * P^{0.67}$ or $E = 55 * P^{0.11} - 40$
A.11	ARM 17.8.324(2)	Hydrocarbon Emissions, Petroleum Products	Oil-effluent Water Separator	-------
A.12	ARM 17.8.324(3)	Hydrocarbon Emissions, Petroleum Products	Gasoline Storage Tanks	-------
A.13, A.14	ARM 17.8.341	National Emission Standards for Hazardous Air Pollutants (NESHAPs)	All Applicable Provisions of 40 CFR 61, Subparts M & FF	-------
A.15	ARM 17.8.342	NESHAPs - General Provisions (40 CFR Part 63)	Start-up, Shutdown, Malfunction (SSM) Plans	Submittal
A.16	ARM 17.8.615	Firefighting Training Permit	Firefighting Requirements	
A.17	ARM 17.74.336	Asbestos Abatement – Annual Permits	Asbestos	-------
A.18	ARM 17.8.1211(1)(c) and 40 CFR Part 98	Greenhouse Gas Reporting	Reporting	-------
A.19	40 CFR Part 68	Chemical Accident Prevention	Risk Management Plan	-------
A.20	40 CFR Part 51	SIP	SO_2	-------
A.21	40 CFR Part 51	SIP	State-Only Requirements	-------
A.22	40 CFR Part 51	SIP	Sulfur Bearing Gases	-------
A.23	40 CFR Part 51	SIP	Quantify Emissions	-------
A.24	ARM 17.8.749 & 17.8.801(7)	Refinery and Terminal	One Source for NSR Purposes	-------
A.25, A.26	40 CFR Part 51	SIP	Reporting	-------

Conditions	Rule Citations	Rule Description	Pollutant/Parameters	Limit
A.27	ARM 17.8.1212	Streamlining	Various	As specified
A.28	40 CFR 63 Subpart CC	Miscellaneous Maintenance Process Vent Provisions	VOC HAPs	-------
A.29	40 CFR 63 Subpart CC	Fenceline Monitoring	Benzene	-------
A.30	ARM 17.8.1212	Reporting Requirements	Prompt Deviation Reporting	-------
A.31	ARM 17.8.1212	Maintain Records	5 Years	-------
A.32	ARM 17.8.1212	Reporting Requirements	Compliance Monitoring	-------
A.33	ARM 17.8.1207	Reporting Requirements	Annual Certifications	-------

Conditions

A.1. Pursuant to ARM 17.8.105, any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of DEQ, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct test, emission or ambient, for such periods of time as may be necessary using methods approved by DEQ.

Compliance demonstration frequencies that list "as required by DEQ" refer to ARM 17.8.105. In addition, for such sources, compliance with limits and conditions listing "as required by DEQ" as the frequency, is verified annually using emission factors and engineering calculations by DEQ's compliance inspectors during the annual emission inventory review; in the case of Method 9 tests, compliance is monitored during the regular inspection by the compliance inspector.

A.2. Pursuant to ARM 17.8.106, all emission source testing, sampling, and data collection, recording analysis, and transmittal must be performed, maintained, and reported in accordance with the Montana Source Test Protocol and Procedures Manual (dated July 1994 unless superseded by rulemaking), unless alternate methods are approved by DEQ.

A.3. Pursuant to ARM 17.8.304(1), ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes, unless otherwise specified by rule or in this permit. This rule does not apply to emissions from new stationary sources listed in ARM 17.8.340 for which a visible emission standard has been promulgated.

A.4. Pursuant to ARM 17.8.304(2), ExxonMobil shall not 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, unless otherwise specified by rule or in this permit. This rule does not apply to emissions from new stationary sources listed in ARM 17.8.340 for which a visible emission standard has been promulgated.

A.5. Pursuant to ARM 17.8.304(3), during the building of new fires, cleaning of grates, or soot blowing, the provisions of ARM 17.8.304(1) and (2) shall apply, except that a maximum average opacity of 60% is permissible for not more than one 4-minute period in any 60 consecutive minutes. Such a 4-minute period means any 4 consecutive minutes.

A.6. Pursuant to ARM 17.8.308(1), ExxonMobil shall not cause or authorize the production, handling, transportation, or storage of any material unless reasonable precautions to control emissions of particulate matter are taken. Such emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes, unless otherwise specified by rule or in this permit.

A.7. Pursuant to ARM 17.8.308(2), ExxonMobil shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter, unless otherwise specified by rule or in this permit.

A.8. Pursuant to ARM 17.8.308(3), ExxonMobil shall not operate a construction site or demolition project unless reasonable precautions are taken to control emissions of airborne particulate matter. Such emissions of airborne particulate matter from any stationary source shall not exhibit an opacity of 20% or greater averaged over 6 consecutive minutes, unless otherwise specified by rule or in this permit.

A.9. Pursuant to ARM 17.8.309, unless otherwise specified by rule or in this permit, ExxonMobil shall not cause or authorize particulate matter caused by the combustion of fuel to be discharged from any stack or chimney into the outdoor atmosphere in excess of the maximum allowable emissions of particulate matter for existing fuel-burning equipment and new fuel-burning equipment calculated using the following equations:

For existing fuel-burning equipment (installed before November 23, 1968):
$E = 0.882 * H^{-0.1664}$

For new fuel-burning equipment (installed on or after November 23, 1968):
$E = 1.026 * H^{-0.233}$

Where H is the heat input capacity in million British thermal units (MMBtu) per hour and E is the maximum allowable particulate emissions rate in pounds per MMBtu. When two or more fuel-burning units are connected to a single stack, the combined heat input of all units connected to the stack shall not exceed that allowable for the same unit connected to a single stack. This rule does not apply to emissions from new stationary sources listed in ARM 17.8.340 for which a visible emission standard has been promulgated.

A.10. Pursuant to ARM 17.8.310, unless otherwise specified by rule or in this permit, ExxonMobil shall not cause or authorize particulate matter to be discharged from any operation, process, or activity into the outdoor atmosphere in excess of the maximum hourly allowable emissions of particulate matter calculated using the following equations:

For process weight rates up to 30 tons per hour: $E = 4.10*P^{0.67}$
For process weight rates in excess of 30 tons per hour: $E = 55.0*P^{0.11} - 40$

Where E = rate of emissions in pounds per hour and P = process weight rate in tons per hour.

A.11. Pursuant to ARM 17.8.324(2), unless otherwise specified by rule or in this permit, ExxonMobil shall not use any compartment of any single or multiple-compartment oil-effluent water separator which compartment receives effluent water containing 200 gallons a day or more of any petroleum product from any equipment processing, refining, treating, storing or handling kerosene or other petroleum product of equal or greater volatility than kerosene, unless such compartment is equipped with a vapor loss control device, constructed so as to prevent emission of hydrocarbon vapors to the atmosphere, properly installed, in good working order and in operation.

A.12. Pursuant to ARM 17.8.324(3), ExxonMobil shall not load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device or is a pressure tank as described in ARM 17.8.324(1), or unless otherwise specified by rule or in this permit.

A.13. ExxonMobil shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements contained in the National Emission Standards for Hazardous Air Pollutants (NESHAPS) provisions, as appropriate, of 40 CFR 61, Subpart M Asbestos.

A.14. ExxonMobil shall manage and treat the facility waste, including each process wastewater stream that meets the definition in 40 CFR 61.341, in accordance with the applicable requirements of 40 CFR 61.342(e) (Subpart FF “BQ6” Alternative). ExxonMobil shall comply with applicable testing, monitoring and inspection, recordkeeping and reporting requirements set out under 40 CFR 61, Subpart FF (ARM 17.8.341).

A.15. Pursuant to ARM 17.8.342 and 40 CFR 63.6, ExxonMobil shall submit to DEQ a copy of any startup, shutdown, and malfunction (SSM) plan required under 40 CFR 63.6(e)(3) within 30 days of the effective date of this operating permit (if not previously submitted), within 30 days of the compliance date of any new National Emission Standard for Hazardous Air Pollutants (NESHAPs) or Maximum Achievable Control Technology (MACT) standard, and within 30 days of the revision of any such SSM plan, when applicable. DEQ requests submittal of such plans in electronic form, when possible.

A.16. Pursuant to ARM 17.8.615, ExxonMobil shall maintain records that they have applied for and, if issued, complied with any Firefighter Training permit to conduct open burning for fire training purposes.

A.17. Pursuant to ARM 17.74.336, ExxonMobil shall comply with all the limitations and requirements of their Asbestos Abatement Annual Permit #MTF07-0004-00, or its’ subsequent revisions.

A.18. Pursuant to ARM 17.8.1211(1)(c) and 40 CFR Part 98, ExxonMobil shall comply with requirements of 40 CFR Part 98 – Mandatory Greenhouse Gas Reporting, as applicable (ARM 17.8.1211(1)(c), NOT an applicable requirement under Title V).

A.19. ExxonMobil shall submit a certification statement to DEQ that states ExxonMobil is in compliance with the requirements of 40 CFR Part 68, including registration and updates of their Risk Management Plan pursuant to §112(r) of the FCAA (40 CFR 68.150, 68.160 and 68.190).

A.20. Pursuant to the June 12, 1998, Board Order and subsequent revisions of March 17, 2000, adopting a SO_2 control plan (Appendix E of this permit), ExxonMobil shall comply with all requirements of Exhibit A and Attachment 1 of the plan. As provided in Section IV.D, the H_2S CEMS provision of the SO_2 Stipulation was subsumed by a streamlined condition. In addition, ExxonMobil shall comply with all terms as set forth by this permit (Board Order signed on June 12, 1998, and subsequent revisions of March 17, 2000; the control plan was partially approved/partially disapproved by EPA on May 2, 2002, and May 22, 2003; parts of the requirement that were disapproved remain "State Only" along with those provisions intended to be "State Only" that were not submitted to EPA).

A.21. Pursuant to the June 12, 1998, Board Order, and subsequent revisions of March 17, 2000, adopting a SO_2 control plan (Appendix E of this permit), ExxonMobil shall comply with all requirements of Exhibit A-1 and corresponding attachments (Board Order signed on June 12, 1998, and subsequent revisions of March 17, 2000; this requirement is "State Only").

A.22. ExxonMobil shall utilize appropriate maintenance, repair, and operating practices to control emissions of sulfur bearing gases from minor sources such as ducts, stacks, valves, vents, vessels, and flanges that are not otherwise subject to the Stipulation and Exhibit A (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

A.23. ExxonMobil shall use good engineering judgment and appropriate engineering calculations to quantify emissions from activities that are not otherwise addressed by the Stipulation and Exhibit A but are known to contribute to emissions from sources listed in Section 1(B) of the Stipulation. In addition, ExxonMobil shall account for such emissions in determining compliance with all applicable emission limits contained in Section 3 of the Stipulation (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002).

A.24. Pursuant to ARM 17.8.749 and 17.8.801(7), the ExxonMobil Refining and Supply Company (a division of Exxon Mobil Corporation) and the Exxon Mobil Corporation Billings Terminal shall be considered one source for the purpose of permitting these facilities under the New Source Review program. Based on the following determinations, the facilities are considered one source:

a. The refinery and the terminal are under common ownership and control;
b. The refinery and the terminal are contiguous and adjacent; and
c. The terminal is considered a support facility to the refinery.

A.25. ExxonMobil shall comply with all reporting requirements of Exhibit A and Attachment 1 of the plan (Billings/Laurel SO_2 Emission Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

A.26. ExxonMobil shall comply with all reporting requirements of Exhibit A-1 of the sulfur dioxide control plan (Board Order signed on June 12, 1998, and subsequent revisions of March 17, 2000; this requirement is "State Only").

A.27. ExxonMobil shall monitor compliance with subsumed conditions by certifying compliance with the streamlined conditions, as designated in Section IV. of this permit (ARM 17.8.1213).

A.28. ExxonMobil shall comply with all applicable requirements of the maintenance process vent provisions of 40 CFR 63 Subpart CC (40 CFR 63.643(c)) (ARM 17.8.302, ARM 17.8.342, 40 CFR 63 Subpart CC).

A.29. ExxonMobil shall comply with all applicable requirements of the fence line monitoring provisions of 40 CFR 63 Subpart CC (40 CFR 63.658) (ARM 17.8.302, ARM 17.8.342, 40 CFR 63 Subpart CC).

A.30. ExxonMobil shall promptly report deviations from permit requirements including those attributable to upset conditions, as upset is defined in the permit. To be considered prompt, deviations shall be reported to DEQ using the schedule and content as described in Section V.E (unless otherwise specified in an applicable requirement) (ARM 17.8.1212).

A.31. ExxonMobil shall maintain, under ExxonMobil's control, all records required for compliance monitoring as a permanent business record for at least 5 years. Furthermore, the records must be available at the plant site for inspection by DEQ and EPA and must be submitted to DEQ upon request (ARM 17.8.1212).

A.32. On or before April 15 and October 15 of each year, ExxonMobil shall submit to DEQ the compliance monitoring reports required by Section V.D. These reports must contain all information required by Section V. D, as well as the information required by each individual emission unit. For the reports due by October 15 of each year, ExxonMobil may submit a single report if it contains all the information required by Sections V.B and V. D. Per ARM 17.8.1207,

> *any application form, report, or compliance certification submitted pursuant to ARM Title 17, Chapter 8, Subchapter 12 (including semiannual monitoring reports), shall contain certification by a responsible official of truth, accuracy, and completeness. This certification and any other certification required under ARM Title 17, Chapter 8, Subchapter 12, shall state that,* ***"based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete."***

A.33. By October 15 of each year, ExxonMobil shall submit to DEQ the compliance certification report required by Section V. B. The annual certification report required by Section V. B must include a statement of compliance based on the information available that identifies any observed, documented or otherwise known instance of noncompliance for each applicable requirement Per ARM 17.8.1207,

> *any application form, report, or compliance certification submitted pursuant to ARM Title 17, Chapter 8, Subchapter 12 (including annual certifications), shall contain certification by a responsible official of truth, accuracy, and completeness. This certification and any other certification required under ARM Title 17, Chapter 8, Subchapter 12, shall state that,* ***"based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete."***

B. EU00: RFG Devices (all heaters/boilers, including 12 Heaters and Boilers not listed in other emitting units)

EU01b: F-3 Heater
EU02a: F-3x Heater
EU02b: F-5 Heater
EU03a: KCOB (also see EU03)
EU03b: F-202 Heater
EU04a: F-700 Heater
EU05a: F-402 Heater
EU07a: F-201 Heater
EU09a: CCOB (also see EU09)
EU11a: F-651 Heater
EU12a: F-551 Heater
EU13: B-8 Boiler (B-8)
EU14b: F-10 Heater
EU16a: F-1201 Heater

Condition(s)	Pollutant/ Parameters	Permit Limits	Compliance Demonstration		Reporting Requirements
			Method	Frequency	
B.1, B.27, B.51, B.60, B.64, B.65	Opacity – Existing Sources	40%	Method 9	As required by DEQ and Section III.A.1	Semiannually and Section III.A.2
B.2, B.27, B.51, B.60, B.64, B.65	Opacity – New Sources	20%			
B.3, B.28, B.51, B.60, B.61, B.64, B.65	PM – Existing Fuel-Burning Equipment	$E = 0.882*H^{-0.1664}$	Method 5	As required by DEQ and Section III.A.1	Semiannually and Section III.A.2
B.3, B.28, B.51, B.60, B.61, B.64, B.65	PM – New Fuel-Burning Equipment	$E = 1.026 * H^{-0.233}$			
B.4, B.29, B.52, B.64, B.65	Fuel Oil Consumption	Prohibited from firing Fuel Oil	Recordkeeping	On-going	Semiannually
B.5, B.30, B.35, B.53, B.64, B.65	RFG	40 CFR 60 Subpart J	40 CFR 60 Subpart J and SIP testing	40 CFR 60 Subpart J and annually	Semiannually, 40 CFR 60 Subpart J, and Section III.A.2
B.6, B.32, B.54, B.55, B.62, B.63, B.64, B.65	Coker Process Gas	Send Coker Process Gas to YELP	Recordkeeping	Ongoing, whenever YELP Operates	Quarterly
B.7, B.30, B.31, B.33, B.34, B.35, B.51, B.53, B.55, B.60, B.61, B.62, B.63, B.64, B.65	SO_2 RFG Units (furnace F-1201 and all other "Affected Equipment and Facilities" identified in Exhibit A of the Stipulation) when YELP is receiving coker process gas	92.4 lb/3-hour period 739.2 lb/day	SO_2/H_2S CEMS, Flow Rate Monitor, Method 11	Ongoing	Quarterly and Section III.A.2

Condition(s)	Pollutant/ Parameters	Permit Limits	Compliance Demonstration		Reporting Requirements
			Method	Frequency	
B.8, B.30, B.31, B.33, B.34, B.35, B.51, B.53, B.55, B.60, B.61, B.62, B.63, B.64, B.65	SO_2 RFG Units(furnace F-1201 and all other "Affected Equipment and Facilities" identified in Exhibit A of the Stipulation) when YELP is *not* receiving coker process gas	76.2 lb/3-hour period 609.6 lb/day	SO_2/H_2S CEMS, Flow Rate Monitor, Method 11	Ongoing	Quarterly and Section III.A.2
B.9, B.36, B.64, B.65	F-1201 RFG/Natural Gas Combustion	811 MMSCF/rolling 12-month period	Recordkeeping	Ongoing	Semiannually and Section III.A.2
B.10, B.37, B.51, B.60, B.61, B.64, B.65	F-1201 NO_X	ULNB - 5.94 lb/hr and 0.060 lb/MMBtu	Source Testing	Every 5 years	
B.11, B.37, B.51, B.60, B.61, B.64, B.65	F-1201 CO	7.77 lb/hr and 0.0785 lb/MMBtu	Source Testing	As required by DEQ and Section III.A.1	
B.12, B.38, B.51, B.60, B.61, B.64, B.65	F-201 NOx	4.7 lb/hr	Source Testing and Engineering Calculations	Source Testing as required by DEQ and Section III.A.1 and ongoing recordkeeping for calculations	
B.13, B.38, B.51, B.60, B.61, B.64, B.65	F-5 NOx	6.27 lb/hr			
B.14, B.38, B.39, B.51, B.60, B.61, B.64, B.65	F-5 & F-201 (combined) NOx	33.30 tons/ rolling 12-month period			
B.15, B.41, B.51, B.60, B.61, B.64, B.65	F-551 NOx	23.35 lb/hr and 75.55 tons/ rolling 12-month period			
B.16, B.40, B.64, B.65	F-700	ULNB	Recordkeeping	Ongoing	
B.17, B.34, B.35, , B.47, B.51, B.57, B.60, B.61, B.63, B.64, B.65	B-8: H_2S in Fuel Gas	162 ppmvd/3 hr 60 ppmvd/365 day	40 CFR 60 Subpart Ja	40 CFR 60 Subpart Ja	Quarterly, Section III.A.2, and 40 CFR 60 Subpart Ja

Condition(s)	Pollutant/ Parameters	Permit Limits	Compliance Demonstration		Reporting Requirements
			Method	Frequency	
B.18, B.42, B.43, B.51, B.55, B.60, B.61, B.62, B.63, B.64, B.65	B-8: SO_2	0.78 lbs/hour	Source Testing	As required by DEQ and Section III.A.1	Semiannually and Section III.A.2
		3.40 tons per rolling 12-month period	Engineering Calculations	Monthly	
B.19, B.44, B.45, B.51, B.60, B.64, B.65	B-8: NO_x	0.04 lb/MMBtu 3.96 lb/hour 17.3 tons per rolling 12-month period	Source Testing Engineering Calculations	Every 5 years Monthly	Semiannually and Section III.A.2
B.20, B.44, B.45, B.51, B.60, B.64, B.65	B-8: CO	0.04 lb/MMBtu 3.96 lb/hour 17.3 tons per rolling 12-month period	Source Testing Engineering Calculations	Every 5 years Monthly	Semiannually and Section III.A.2
B.21, B.46, B.56, B.64, B.65	B-8: Heat Input Rate	99 MMBtu/hr based on a rolling 24-hr average	Continuous Monitoring	Ongoing	Semiannually
B.22, B.29, B.52, B.64, B.65	B-8: Fuel Type	Burn Natural Gas or Refinery Fuel Gas	Recordkeeping	Ongoing	Semiannually
B.23, B.27, B.51, B.64, B.65	B-8: Opacity	20%	Method 9	As Required by DEQ and Section III.A.1	Semiannually
B.24, B.48, B.58, B.64, B.65	RFG Units,	40 CFR 63 Subpart DDDDD Annual Tune-Ups	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	Semiannually and 40 CFR 63 Subpart DDDDD
	F-402 Heater – when burning ASO	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	40 CFR 63 Subpart DDDDD	
B.25, B.49, B.59, B.64, B.65	B-8 Boiler	40 CFR 60 Subpart Dc	40 CFR 60 Subpart Dc	40 CFR 60 Subpart Dc	Semiannually and 40 CFR 60 Subpart Dc

Conditions

B.1. ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes, unless otherwise specified by rule or in this permit. During the building of new fires, cleaning of grates, or soot blowing, the provisions of ARM 17.8.304(1) and (2) shall apply, except that a maximum average opacity of 60% is permissible for not more than one 4-minute period in any 60 consecutive minutes. Such a 4-minute period means any 4 consecutive minutes. This rule does not apply to emissions from new stationary sources listed in ARM 17.8.340 for which a visible emission standard has been promulgated (ARM 17.8.304(1) and ARM 17.8.304(3)).

B.2. ExxonMobil shall not 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, unless otherwise specified by rule or in this permit. During the building of new fires, cleaning of grates, or soot blowing, the provisions of ARM 17.8.304(1) and (2) shall apply, except that a maximum average opacity of 60% is permissible for not more than one 4-minute period in any 60 consecutive minutes. Such a 4-minute period means any 4 consecutive minutes. This rule does not apply to emissions from new stationary sources listed in ARM 17.8.340 for which a visible emission standard has been promulgated (ARM 17.8.304(2) and ARM 17.8.304(3)).

B.3. Unless otherwise specified by rule or in this permit, ExxonMobil shall not cause or authorize particulate matter caused by the combustion of fuel to be discharged from any stack or chimney into the outdoor atmosphere in excess of the maximum allowable emissions of particulate matter for existing fuel-burning equipment and new fuel-burning equipment calculated using the following equations:

For existing fuel-burning equipment (installed before November 23, 1968):
E = 0.882 * H-0.1664

For new fuel-burning equipment (installed on or after November 23, 1968):
E = 1.026 * H-0.233

Where H is the heat input capacity in MMBtu per hour and E is the maximum allowable particulate emissions rate in pounds per MMBtu. When two or more fuel-burning units are connected to a single stack, the combined heat input of all units connected to the stack shall not exceed that allowable for the same unit connected to a single stack (ARM 17.8.309).

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

B.5. ExxonMobil shall comply with all applicable requirements of 40 CFR 60 Subpart J – Standards of Performance for Petroleum Refineries, as it applies to fuel gas combustion devices. ExxonMobil shall not burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 milligrams per dry standard cubic meter (mg/dscm) (0.10 grains per dry standard cubic foot (gr/dscf) or 162 parts per million volume dry basis (ppmvd)) per rolling 3-hour period (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart J).

B.6. ExxonMobil shall, any time the YELP facility is operating, send all of its Coker process gas to either one or both of YELP's boilers. During startup and shutdown conditions at YELP, ExxonMobil shall supply the maximum amount of Coker process gas that YELP can accept (ARM 17.8.749).

B.7. The following combined emission limitations shall apply to furnace F-1201 and all other "Affected Equipment and Facilities" identified in Exhibit A of the Stipulation of DEQ and ExxonMobil whenever the YELP facility is receiving ExxonMobil coker flue gas or whenever ExxonMobil's coker unit is not operating (ARM 17.8.749).

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

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

B.8. The following combined emission limitations shall apply to furnace F-1201 and all other "Affected Equipment and Facilities" identified in Exhibit A of the Stipulation of DEQ and ExxonMobil whenever the YELP facility is not receiving ExxonMobil's coker unit flue gas and ExxonMobil's coker unit is not operating (ARM 17.8.749).

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

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

B.9. Furnace F-1201 shall not consume more than 811 million standard cubic feet (MMscf) of RFG and natural gas combined during any rolling 12-month period (ARM 17.8.749).

B.10. Ultra-low NO_x Burners (ULNB) shall be used in furnace F-1201 to control NO_x emissions. The NO_x emissions shall not exceed 5.94 pounds per hour (lb/hr) and 0.060 pounds per million British thermal units (lb/MMBtu) (ARM 17.8.752).

B.11. The CO emissions from furnace F-1201 shall not exceed 7.77 lb/hr and 0.0785 lb/MMBtu (ARM 17.8.749).

B.12. NO_x emissions from F-201 shall not exceed 4.70 lb/hr (ARM 17.8.752).

B.13. NO_x emissions from F-5 shall not exceed 6.27 lb/hr (ARM 17.8.752).

B.14. The combined NO_x emissions from F-201 and F-5 shall not exceed 33.30 tons per rolling 12-month period (ARM 17.8.752).

B.15. NO_x emissions from F-551 shall not exceed 23.35 lb/hr (ARM 17.8.749) and 75.55 tons per rolling 12-month period (ARM 17.8.752).

B.16. ULNB shall be installed and operating on F-700 (Consent Decree Paragraph 45).

B.17. If Boiler B-8 is modified to combust RFG, ExxonMobil shall not burn fuel gas in B-8 that contains H_2S in excess of 162 ppmvd determined hourly on a 3-hr rolling average basis and H_2S in excess of 60 ppmvd determined daily on a 365 successive calendar day rolling average basis, as measured in accord with 40 CFR 60 Subpart Ja (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Ja).

B.18. SO_2 emissions from B-8 shall not exceed 3.40 tons per rolling 12-month period and 0.78 lb/hr (ARM 17.8.749).

B.19. The NO_x emissions from B-8 shall not exceed:

a. 0.04 lb/MMBtu based on a one-hour average and corrected to 3% excess O_2, on a dry basis, not applicable during start-up[1] and shutdown[1] (ARM 17.8.749 and ARM 17.8.752)

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

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

B.20. The CO emissions from B-8 shall not exceed:

a. 0.04 lb/MMBtu based on a one-hour average and corrected to 3% excess O_2, on a dry basis, not applicable during start-up[1] and shutdown[1] (ARM 17.8.749 and ARM 17.8.752)

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

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

B.21. The heat input rate of B-8 shall not exceed 99 MMBtu-HHV/hr averaged over any rolling 24-hr period (ARM 17.8.749).

B.22. ExxonMobil shall burn only natural gas or refinery fuel gas in the B-8 Boiler (ARM 17.8.749, ARM 17.8.752).

B.23. ExxonMobil shall not cause or authorize to be discharged into the atmosphere from B-8, any visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. (ARM 17.8.304)

B.24. ExxonMobil shall comply with all applicable requirements of 40 CFR 63 Subpart DDDDD – NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (ARM 17.8.342 and 40 CFR 63 Subpart DDDDD. Each applicable heater and boiler is considered an "affected facility")

B.25. ExxonMobil shall comply with all applicable requirements of 40 CFR 60 Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Boilers, including as applicable to the B-8 Boiler (ARM 17.8.342 and 40 CFR 60 Subpart Dc).

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

B.26. ExxonMobil shall provide written notification to DEQ as follows (ARM 17.8.749):

a. Notification of completion of modification of Boiler B-8 within 30 days after the B-8 boiler is made capable of combusting refinery fuel gas

b. Notification of startup of the boiler within 15 days of initial startup of the B-8 boiler after the boiler has been made capable of combusting refinery fuel gas

Compliance Demonstration

B.27. As required by DEQ and Section III.A.1, compliance with the opacity limitations listed in Sections III.B.1, III.B.2, and III.B.23 shall be monitored using EPA reference Method 9 testing by a qualified observer (ARM 17.8.1213).

B.28. As required by DEQ and Section III.A.1, compliance with the PM limits in Section III.B.3 shall be monitored by conducting Method 5 tests on the heater/boiler stacks (ARM 17.8.749 and ARM 17.8.105).

B.29. Compliance with Section III.B.4 and III.B.22 shall be documented by recordkeeping as required by Section III.B.52. This requirement is considered to also monitor compliance with ARM 17.8.322(4) Sulfur in Fuel (liquid and solid) (ARM 17.8.1213).

B.30. ExxonMobil shall conduct all monitoring and testing as required by 40 CFR 60 Subpart J to monitor compliance with Section III.B.5. ExxonMobil shall install, calibrate, maintain, and operate a H_2S continuous monitoring system to continuously monitor and record the concentration (dry basis) of H_2S in the RFG before being burned in any fuel gas combustion device, or develop an AMP, as required by 40 CFR 60, Subparts A and J. Compliance with the fuel gas H_2S concentration limit set out in Section III.B.5 shall be determined based on 3-hour rolling average H_2S concentrations, determined by utilizing data taken from the continuous monitoring system and other Department-approved sampling methods. The H_2S monitoring system shall be installed, certified, and operated in accordance with Performance Specification 7 (40 CFR Part 60, Appendix B) to meet applicable provisions of 40 CFR 60.105(a)(4), 60.7, and 60.13. The H_2S monitoring system shall meet the quality assurance and quality control requirements set out in 40 CFR Part 60, Appendix F (annual RATA), as provided by the SO_2 Stipulation. The monitoring system shall meet applicable quarterly data recovery rates and other provisions of §6(A) of the SO_2 Stipulation. This requirement is considered to also monitor compliance with the refinery-block hourly limit of 0.96 lb/MMBtu (ARM 17.8.749, ARM 17.8.1213, ARM 17.8.340, and 40 CFR 60 Subpart J; Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

B.31. ExxonMobil shall operate and maintain a continuous flow rate monitor on the RFG header. Accuracy determinations for the refinery fuel flow rate monitor shall be required at least once every 48 months or more frequently as routine refinery turn-arounds allow (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

B.32. Any time ExxonMobil diverts process coker gases from YELP, ExxonMobil shall report said diversion to DEQ within 24 hours or during the next regular working day. This information shall also be included in the quarterly report required in Section III.B.63 and shall include the period(s) of diversion, quantity of SO_2 emissions, reason for the diversion(s), and corrective measures taken to prevent reoccurrence (ARM 17.8.1213).

B.33. Compliance with the combined SO_2 emission limitation for the fuel gas combustion units contained in Sections III.B.7 and III.B.8 of this permit shall be monitored by using hourly-average H_2S concentrations for the RFG as required by Section III.B.30, and hourly-average fuel gas-firing rates from the CEMS required by Exhibit A, Section 6(B)(8) of the Stipulation and in accordance with the appropriate equation(s) in Exhibit A, Section 2(A)(1), (8), (11), and (16) of the Stipulation except when CEMS data is not available as provided in Exhibit A, Section 2(A)(16) of the Stipulation (Appendix E of this permit). When the H_2S concentration in the RFG stream exceeds 1200 ppmv, ExxonMobil shall initiate sampling within 4 hours the H_2S concentration in the RFG according to the procedures in paragraphs (f)(3)(ii)(B-C) of the FIP (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003, ARM 17.8.340 and 40 CFR 60, Subpart J, ARM 17.8.1213, and Federal Implementation Plan for the Billings/Laurel Area FR Vol. 73, No. 77, April 21, 2008).

B.34. In the event the H_2S CEMS is unable to meet minimum availability requirements, ExxonMobil shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be monitored. DEQ shall approve such contingency plans. H_2S CEMS shall be required to be maintained such that they are available and operating at least 90% of the source operating time during any reporting period (quarterly) (ARM 17.8.749 and Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

B.35. ExxonMobil shall perform annual H_2S source testing using EPA-approved methods (40 CFR Part 60, Appendix A, Method 11) or an equivalent method approved by DEQ and EPA, and in accordance with Section III.A.2 (ARM 17.8.106) (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

B.36. ExxonMobil shall document, by month, the total amount of RFG/natural gas consumed by furnace F-1201. By the 25th day of each month ExxonMobil shall calculate the total amount of RFG/natural gas consumed by furnace F-1201 during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section III.B.9. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749). ExxonMobil shall also calculate and record, by the 25th day of each month, the 12-month rolling sum. The 12-month rolling sums for the months in the semiannual reporting period shall be submitted in the Title V semiannual report (or reference to information already submitted made) (ARM 17.8.1213).

B.37. ExxonMobil shall test F-1201 on an every 5-year basis after the initial source test, or according to another testing/monitoring schedule as may be approved by DEQ, to demonstrate compliance with the NO_X limitations for furnace F-1201for NO_x found in Section III.B.10 (ARM 17.8.749 and ARM 17.8.106). ExxonMobil shall test F-1201 for CO, concurrently with NO_X testing, in accordance with Section III.A.2 (ARM 17.8.106), as required by DEQ and Section III.A.1 to monitor compliance with the CO limitations found in Sections III.B.11 (ARM 17.8.106 and ARM 17.8.1213).

B.38. ExxonMobil shall test F-201 and F-5 for NO_x in accordance with Section III.A.2 (ARM 17.8.106), as required by DEQ and Section III.A.1 to monitor compliance with the NO_x limitations found in Sections III.B.12, III.B.13, and III.B.14 (ARM 17.8.1213). In addition to any required testing, ExxonMobil shall document by month, the average monthly percent of maximum firing rate, the monthly gas consumption (MMscf per month), the input fuel heat content (MMBtu/MMscf), and the monthly hours of operation of F-201 and F-5 for use in the following equations (ARM 17.8.106 and ARM 17.8.749):

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

Where:

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

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

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

NO_X tons per month = {NO_X (lb/hr) * (hr/month)} / 2000 lb/ton

B.39. ExxonMobil shall document, by month, the amount of total NO_X emissions from F-201 and F-5. By the 25th day of each month ExxonMobil shall calculate and document the total amount of NO_X emissions from F-201 and F-5 during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section III.B.14. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749). By the 25th day of each month, ExxonMobil shall calculate and document the 12-month rolling sum of NO_X emissions from F-201 and F-5. The 12-month rolling sums for the months in the semiannual reporting period shall be submitted in the Title V semiannual report (or reference to information already submitted made) (ARM 17.8.1213).

B.40. ExxonMobil shall document any time the ULNB is not installed and operating on F-700. The information shall be included in the Title V Semiannual report (ARM 17.8.1213).

B.41. ExxonMobil shall test F-551 on an every 5-year basis after the initial source test, or according to another testing/monitoring schedule as may be approved by DEQ, to demonstrate compliance with the NO_X limitation in Section III.B.15 (ARM 17.8.106 and 17.8.749).

B.42. As required by DEQ and Section III.A.1, compliance with the hourly SO_2 limit in Section III.B.18 shall be monitored by conducting a Method 6 or 6C test on the B-8 boiler stack (ARM 17.8.1213).

B.43. ExxonMobil shall document, by month, the amount of total SO_2 emissions from the B-8 boiler. By the 25th of each month, ExxonMobil shall calculate and document the total amount of SO_2 emissions from the B-8 boiler during the previous month. The monthly information will be used to monitor compliance with the rolling 12-month limitation in Section III.B.18. The information for each of the previous months shall be submitted along with the annual emission inventory. By the 25th day of each month, ExxonMobil shall also calculate and document the 12-month rolling sum of SO_2 emissions. The 12-month rolling sums for the months in the semiannual reporting period shall be submitted in the Title V semiannual report (ARM 17.8.1213).

B.44. B-8 shall be tested on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by DEQ, for NO_X and CO concurrently, and the results submitted to DEQ in order to demonstrate compliance with the lb/hr and lb/MMBtu emission limits contained in Section III.B.19 and Section III.B.20 (ARM 17.8.105 and ARM 17.8.749).

B.45. ExxonMobil shall document, by month, the amount of total NO_x and CO emissions from the B-8 boiler. By the 25th of each month, ExxonMobil shall calculate and record the total amount of NO_x and CO emissions from the B-8 boiler during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitations in Section III.B.19 and Section III.B.20. The information for each of the previous months shall be submitted along with the annual emission inventory. By the 25th of each month, ExxonMobil shall also calculate and document the 12 month rolling sums. The 12-month rolling sums for the months in the semiannual reporting period shall be submitted in the Title V semiannual report (ARM 17.8.1213).

B.46. ExxonMobil shall continuously monitor the heat input rate into B-8 and provide averages on a rolling 24-hour basis. This information shall be used to verify compliance with the rolling 24-hr average limitation in Section III.B.21 (ARM 17.8.1213).

B.47. ExxonMobil shall conduct all monitoring and testing as required by 40 CFR 60 Subpart Ja, Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced after May 14, 2007, to monitor compliance with Section III.B.17. ExxonMobil shall install, calibrate, maintain, and operate a H_2S continuous emissions monitoring system (CEMS) to continuously monitor and record the concentration (dry basis) of H_2S in the RFG before being burned in any fuel gas combustion device, or develop an AMP, as required by 40 CFR 60, Subparts A and Ja. Compliance with the fuel gas H_2S concentration limit set out in Section III.B.17 shall be determined based on 3-hour rolling average H_2S concentrations, determined by utilizing data taken from the CEMS and other Department-approved sampling methods. The H_2S CEMS shall be installed, certified, and operated in accordance with Performance Specification 7 (40 CFR Part 60, Appendix B) to meet applicable provisions of 40 CFR 60.105(a)(4), 60.7, and 60.13. The H_2S CEMS shall meet the quality assurance and quality control requirements set out in 40 CFR Part 60, Appendix F (annual RATA), as provided by the SO_2 Stipulation. The CEMS shall meet applicable quarterly data recovery rates and other provisions of §6(A) of the SO_2 Stipulation. Compliance with this requirement is considered to also monitor compliance with the refinery-block hourly limit of 0.96 lb/MMBtu (ARM 17.8.340 and 40 CFR 60, Subpart Ja; ARM 17.8.749; Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

B.48. ExxonMobil shall comply with all applicable testing, continuous compliance, recordkeeping, reporting, and work practice standards of 40 CFR 63 Subpart DDDDD. Pursuant to 40 CFR 63.7540(a)(10) and 40 CFR 63 Subpart DDDDD Table 3, an annual tune-up is required as a compliance demonstration for boiler or process heaters greater than 10 MMBtu/hr. Tune-ups must be performed within 13 months of the last conducted tune-up pursuant to 40 CFR 63.7515(d). Pursuant to 40 CFR 63.7515(a), 40 CFR 63.7520, and 40 CFR 63 Subpart DDDDD Table 2, performance testing is required for the F-402 Heater when burning acid soluble oil (ASO) which is characterized as heavy liquid fuel unless specified under 40 CFR 63.7515 (b)-(e) or (g) (ARM 17.8.342 and 40 CFR 63 Subpart DDDDD).

B.49. ExxonMobil shall comply with all applicable compliance and performance test methods and procedures and emissions monitoring requirements of 40 CFR 60 Subpart Dc (ARM 17.8.340 and 40 CFR 60 Subpart Dc).

B.50. ExxonMobil shall maintain on-site a copy of notifications made to DEQ fulfilling the requirements of Section III.B.26 (ARM 17.8.1213).

Recordkeeping

B.51. ExxonMobil shall perform all source test recordkeeping in accordance with the appropriate test method and Section III.A.2 (ARM 17.8.106).

B.52. ExxonMobil shall maintain records of fuel type burned to monitor compliance with Section III.B.4 and III.B.22 (ARM 17.8.1213).

B.53. ExxonMobil shall conduct all applicable recordkeeping requirements in accordance with 40 CFR 60, Subpart J. ExxonMobil shall maintain a file of all fuel gas H_2S measurements and SO_2 emissions, including CEMS, monitoring device, and performance testing measurements; all CEMS performance evaluations; all CEMS or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR Part 60 (ARM 17.8.1212, ARM 17.8.340, and 40 CFR 60 Subpart J).

B.54. ExxonMobil shall keep records of any time ExxonMobil diverts process Coker gases from YELP for 5 years. This information shall include the period(s) of diversion, quantity of sulfur oxide emissions, reason for the diversion(s), and corrective measures taken to prevent reoccurrence, as required by Section III.B.32 (ARM 17.8.1212).

B.55. In accordance with the Stipulation, ExxonMobil shall record, organize, report, and archive all the data specified in Section 7(C) of the Stipulation (Appendix E of this permit) (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

B.56. ExxonMobil shall document any exceedances of the rolling 24-hr average limitation specified in Section III.B.21. Any exceedance shall be reported and submitted with the semiannual report required in Section III.B.65 (ARM 17.8.749).

B.57. ExxonMobil shall conduct all applicable recordkeeping requirements in accordance with 40 CFR 60, Subpart Ja. ExxonMobil shall maintain a file of all fuel gas H_2S measurements and SO_2 emissions, including CEMS, monitoring device, and performance testing measurements; all CEMS performance evaluations; all CEMS or monitoring device calibration checks; adjustments and maintenance performed on these systems or devices; and all other information required by 40 CFR Part 60 (ARM 17.8.1212, ARM 17.8.340 and 40 CFR 60 Subpart Ja).

B.58. ExxonMobil shall conduct all recordkeeping as required by 40 CFR 63 Subpart DDDDD (ARM 17.8.342 and 40 CFR 63, Subpart DDDDD).

B.59. ExxonMobil shall conduct all recordkeeping as required by 40 CFR 60 Subpart Dc (ARM 17.8.340 and 40 CFR 60 Subpart Dc).

Reporting

B.60. Any required compliance source test report(s) shall be submitted in accordance with Section III.A.2 (ARM 17.8.106).

B.61. ExxonMobil shall notify DEQ in writing of each source test or RATA a minimum of 25 working days prior to the actual testing, unless otherwise specified by DEQ (Billings/Laurel SO_2 Emission Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

B.62. In accordance with Section 7 of the Stipulation (Appendix E of this permit), ExxonMobil shall submit quarterly reports within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to DEQ's Permitting and Compliance office in Helena and the Billings Regional Office. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written or hard copy data summary report (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

B.63. ExxonMobil shall provide quarterly emission reports within 30 days of the end of each calendar quarter. Emission reporting for SO_2 from all point source locations shall consist of 24-hour calendar-day totals per quarter. The quarterly report shall also include the following:

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

b. Monitoring downtime that occurred during the reporting period;

c. A summary of excess H_2S concentrations and/or SO_2 emissions and averaging period;

d. Any time ExxonMobil diverts process Coker gases from YELP, ExxonMobil shall include the following information in the quarterly SO_2 SIP report: the period(s) of diversion, quantity of SO_2 emissions, reason for the diversion(s), and corrective measures taken to prevent reoccurrence; and

e. Reasons for any emissions in excess of those specifically allowed in Sections III.B.5, III.B.7, and III.B.8, with mitigative measures utilized and corrective actions taken to prevent a recurrence of the upset situation.

B.64. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1213)

B.65. The semiannual compliance monitoring reports shall provide a summary of any required monitoring, with all instances of deviations from permit requirements clearly identified. The report shall include the following (ARM 17.8.1212):

a. A summary of the results of any required reference method tests performed during the reporting period;

b. Summary of the fuel records required by Section III.B.52. A statement that no fuel oil was burned may suffice for this requirement for semiannual reporting periods in which no fuel oil was burned.

c. The 12-month rolling sums for the months in the semiannual reporting period required by Section III.B.36;

d. The 12-month rolling sums for the months in the semiannual reporting period for NO_X emissions from F-201 and F-5 as required by Section III.B.39, calculated in accord to Section III.B.38;

e. The 12-month rolling sums of the SO_2 emissions of the B-8 boiler for the months in the semiannual reporting period as required by Section III.B.43;

f. The 12-month rolling sums of the NO_x and CO emissions of the B-8 boiler for the months in the semiannual reporting period as required by Section III.B.45;

g. Any records created as required by Section III.B.40

h. Summary of the heat input rate into B-8 records as required by Section III.B.46. Statistics such as the highest 24-hour average during the reporting period, or during a calendar month, for those periods in which no exceedance occurred, would suffice;

i. Reference to dates that quarterly reports were submitted;

j. Reference to dates that the notification requirements related to Boiler B-8 were made, or written update on status of the modification;

k. Summary of compliance with the reporting requirements of 40 CFR 63 Subpart DDDDD during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 63 Subpart DDDDD;

l. Summary of compliance with the reporting requirements of 40 CFR 60 Subpart J during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 60 Subpart J;

m. Summary of compliance with the reporting requirements of 40 CFR 60 Subpart Ja during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 60 Subpart Ja.

n. Summary of compliance with the reporting requirements of 40 CFR 60 Subpart Dc during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 60 Subpart Dc.

C. EU01 – Crude – APS and VPS

EU01a: F-2 Crude Vacuum Heater (F-1 Crude Furnace/F-401 Vacuum Heater)
EU01c: D-4 Drum Atmospheric Stack

Condition(s)	Pollutant/Parameters	Permit Limits	Compliance Demonstration Method	Frequency	Reporting Requirements
C.1, C.5, C.10, C.14, C.15, C.16	Opacity	40%/60% for Soot Blowing	Method 9	As Required by DEQ and Section III.A.1	Semiannually and Section III.A.2
C.2, C.6, C.15, C.16	H_2S – D-4 Drum Vent	Steam Injection	Recordkeeping	As necessary	Semiannually
C.3, C.7, C.8, C.11, C.13, C.15, C.16	SO_2 F-2 Crude/ Vacuum Heater Stack	271.4 lb/3-Hr 2,171.2 lb/day	SWS CEMS, & Sampling	Ongoing	Quarterly
C.4, C.9, C.11, C.12, C.13, C.15, C.16	Burning SWSOH in F-1 Crude Furnace or the Flare	Electronic Sensor on Valve Supplying SWSOH	Operate Sensor on the Valve and Perform Recordkeeping	Whenever Valve is Opened	Semiannually

Conditions

C.1. ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere, from the F-2 Crude Vacuum Heater stack and the D-4 Drum atmospheric vent stack, that exhibit opacity of 40% or greater averaged over 6 consecutive minutes. During the building of new fires, cleaning of grates, or soot blowing, the provisions of ARM 17.8.304(1) and (2) shall apply, except that a maximum average opacity of 60% is permissible for not more than one 4-minute period in any 60 consecutive minutes. Such a 4-minute period means any 4 consecutive minutes (ARM 17.8.304(1) and ARM 17.8.304(3)).

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

C.3. The following emission limitations shall apply to the F-2 Crude/Vacuum Heater Stack (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

a. SO_2 3-hour emissions from the F-2 Crude/Vacuum Heater Stack shall not exceed 271.4 pounds per 3-hour period, and Daily Emissions of SO_2 from the F-2 Crude/Vacuum Heater Stack shall not exceed 2,171.2 pounds per calendar day.

C.4. SWSOH may be burned in the F-1 Crude Furnace (and exhausted through the F-2 Crude/Vacuum Heater stack) or in the flare during periods when the CCOB is unable to burn the SWSOH, provided that:

a. Such periods do not exceed 55 days per calendar year and 65 days for any 2 consecutive calendar years, and

b. During such periods, the sour water stripper system is operating in a two-tower configuration.

(Board Order signed on June 12, 1998, and subsequent revisions of March 17, 2000; this requirement is "State Only").

Compliance Demonstration

C.5. As required by DEQ and Section III.A.1, ExxonMobil shall perform a Method 9 test in accordance with Section III.A.2 (ARM 17.8.105, ARM 17.8.106, and ARM 17.8.1213).

C.6. ExxonMobil shall provide comment and explanation whenever the steam injection capability did not operate during periods when H_2S was being released or was expected to be released from a process unit to the D-4 Drum (ARM 17.8.1213).

C.7. In accordance with the Stipulation (Appendix E of this permit), ExxonMobil shall operate and maintain a continuous flow rate monitor to determine the sour water flow rate to the T-23 stripper tower. Accuracy determinations for the sour water flow rate monitor shall be required at least once every 48 months and within three months prior to any scheduled shutdown of the CCOB and shall be conducted in accordance with Attachment #2 of the Stipulation (or another method approved by DEQ and EPA) (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

C.8. The following requirements apply only in the event of a loss of the H_2O_2 treatment system and when SWSOH gas is being routed to the F-1 Crude Furnace. Whenever SWSOH are being burned in the F-1 Crude (and exhausted through the F-2 Crude/Vacuum Heater stack) Furnace or in the flare, compliance with the emission limitations contained in Section III.C.3 of this permit shall be monitored using flow rate monitoring data required by Exhibit A, Section 6(B)(9) of the Stipulation (Appendix E) and from sampling and analysis of the sour water feed to the T-23 sour water stripper tower. Except for the first 2 hours after SWSOH are directed to the F-1 Crude Furnace, ExxonMobil shall collect at least one sample from the sour water feed to the T-23 sour water stripper tower for each of the eight non-overlapping 3-hour periods in a calendar day. In addition, the time elapsed before collection of the first sample shall not exceed 4 hours. ExxonMobil shall analyze the sample for H_2S in accordance with the procedures contained in Attachment #2 of the Stipulation (or another method approved by DEQ and EPA), and ExxonMobil shall use the results to calculate the hourly SO_2 emission rate for each of the hours in the 3-hour period in accordance with the equations in Exhibit A, Section 2 (A) (1), (8), (11), and (16) of the Stipulation (Appendix E of this permit).

Notwithstanding the fact that fuel gas combustion emissions from the F-2 Crude/Vacuum Heater are measured by the fuel gas system CEMS and counted against the emission limitations contained in Section 3 (A)(1) and (B)(2) of the Stipulation (Appendix E of this permit), such emission are also counted against the emission limitations contained in Section

3 (A)(2) and (B)(3) of the Stipulation (Appendix E) if for any reason source testing is conducted on the F-2 Crude/Vacuum Heater stack. The requirement for the sampling and analysis of the sour water feed has been subsumed by Section III.F.9 which requires ExxonMobil to treat this stream in accordance with 40 CFR 60, Subparts A and J (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

C.9. ExxonMobil shall operate an electronic sensor on the valve, which supplies SWSOH to the F-1 Crude Furnace and/or the flare. The electronic sensor shall be electronically integrated with the Data Acquisition System (DAS) to ensure that each time the valve is opened (SWSOH to the F-1 Crude Furnace or the flare) the DAS automatically records the date and time that the valve is opened and the length of time the SWSOH are directed to the 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; Flare requirements are "State-only").

Recordkeeping

C.10. All source test recordkeeping shall be performed in accordance with the test method being used and Section III.A.2 (ARM 17.8.106).

C.11. In accordance with the Stipulation, ExxonMobil shall record, organize, report, and archive all the data specified in Section 7(C) of the Stipulation (Appendix E of this permit) (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

C.12. Whenever the valve which supplies SWSOH to the F-1 Crude Furnace is opened, ExxonMobil shall log the date and time and the reasons for such action (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

Reporting

C.13. In accordance with Section 7 of the Stipulation (Appendix E of this permit), ExxonMobil shall submit quarterly reports within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to DEQ's Permitting and Compliance office in Helena and the Billings Regional Office. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written or hard copy data summary report (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

C.14. Any required compliance source test report(s) shall be submitted in accordance with Section III.A.2 (ARM 17.8.106).

C.15. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1213)

C.16. The semiannual compliance monitoring reports shall provide a summary of any required monitoring, with all instances of deviations from permit requirements clearly identified. The report shall include the following (ARM 17.8.1212):

a. A summary of the results of any required reference method tests performed during the reporting period;

b. A summary of the comment and explanation requirements of Section III.C.6

c. A summary of the reports including dates as required by Sections III.C.11 and III.C.12

d. Reference to dates that quarterly reports were submitted

D. EU03 – Coker – Fluid Coker

EU03a: Coker CO Boiler (KCOB)
EU03c: Coker Process Gas Group I Miscellaneous Process Vent

Condition(s)	Pollutant/Parameters	Permit Limits	Compliance Demonstration Method	Frequency	Reporting Requirements
D.1, D.7, D.8, D.9, D.10, D.18, D.19, D.23, D.24, D.28, D.29	Opacity KCOB and F-202 (exhausts through KCOB stack)	20%/60% for Soot Blowing	Method 9	As required by DEQ and Section III.A.1	Semiannually and Section III.A.2
			COMS: 40 CFR Part 51, Appendix P and 40 CFR Part 60 Appendix B Specification 1	Ongoing	Quarterly
D.2, D.8, D.12, D.18, D.19, D.23, D.24, D.26, D.28, D.29	PM, Fuel-Burning Equipment (KCOB and F-202 (exhausts through KCOB stack))	$E = 0.882 * H^{-0.1664}$ or $E = 1.026 * H^{-0.233}$	Method 5	Once every 5 yrs when YELP is down	Semiannually and Section III.A.2
			CAM (COMS)	Continuous	Quarterly
D.3, D.8, D.12, D.18, D.19, D.23, D.24, D.26, D.28, D.29	PM, Process Weight KCOB	$E = 4.10 * P^{0.67}$ or $E = 55.0 * P^{0.11} - 40$	Method 5	Once every 5 yrs when YELP is down	Semiannually and Section III.A.2
			CAM (COMS)	Continuous	Quarterly
D.4, D.13, D.20, D.21, D.25, D.26, D.28, D.29	Coker Process Gas	Send all Coker Process gas to YELP	Recordkeeping	Ongoing, whenever YELP Operates	Quarterly
D.5, D.14, D.15, D.16, D.18, D.19, D.21, D.23, D.26, D.27, D.28, D.29	SO_2 KCOB (when YELP is not operating)	2,142.9 lb/3-Hr 17,143.1 lb/day	SO_2 CEMS	Ongoing	Quarterly
			Flow Rate Monitor	Ongoing	Quarterly
			RATA Methods 1-4 & 6/6C	Annually	Semiannually
D.6, D.17, D.22, D.28, D.29	Misc. Process Vents	As required by 40 CFR 63.643	Monitoring and Testing	As required by 40 CFR 63.644 & 645	Semiannually and 40 CFR 63 Subpart CC

Conditions

D.1. ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere, from the KCOB stack, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes. During the building of new fires, cleaning of grates, or soot blowing, the provisions of ARM 17.8.304(1) and (2) shall apply, except that a maximum average opacity of 60% is permissible for not more than one 4-minute period in any 60 consecutive minutes. Such a 4-minute period means any 4 consecutive minutes (ARM 17.8.304(2) and ARM 17.8.304(3)).

D.2. ExxonMobil shall not cause or authorize particulate matter caused by the combustion of fuel to be discharged from any stack or chimney into the outdoor atmosphere in excess of the maximum allowable emissions of particulate matter for existing fuel-burning equipment and new fuel-burning equipment calculated using the following equations:

For existing fuel-burning equipment (installed before November 23, 1968):
E = 0.882 * H-0.1664 (F-202 Heater Stack)

For new fuel-burning equipment (installed on or after November 23, 1968):
E = 1.026 * H-0.233 (KCOB Coker CO Boiler Stack)

Where H is the heat input capacity in MMBtu per hour and E is the maximum allowable particulate emissions rate in pounds per MMBtu (ARM 17.8.309(2)). When two or more fuel-burning units are connected to a single stack, the combined heat input of all units connected to the stack shall not exceed that allowable for the same unit connected to a single stack (ARM 17.8.309(3)).

D.3. ExxonMobil shall not cause or authorize particulate matter to be discharged from any operation, process, or activity into the outdoor atmosphere in excess of the maximum hourly allowable emissions of particulate matter calculated using the following equations:

For process weight rates up to 30 tons per hour: $E = 4.10 * P^{0.67}$
For process weight rates in excess of 30 tons per hour: $E = 55.0 * P^{0.11} – 40$

Where E is the rate of emissions in pounds per hour and P is the process weight rate in tons per hour (ARM 17.8.310).

D.4. ExxonMobil shall, any time the YELP facility is operating, send all of its Coker process gas to either or both of YELP's boilers. During start-up and shutdown conditions at YELP, ExxonMobil shall supply the maximum amount of Coker process gas that YELP can accept (ARM 17.8.749).

D.5. The following emission limitations shall apply to the KCOB stack (includes process exhaust gases and F-202 Heater fuel gas-firing emissions) whenever YELP is not receiving ExxonMobil Coker process gas and the ExxonMobil Coker unit is operating (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

a. SO_2 emissions from the KCOB stack shall not exceed 2,142.9 pounds per 3-hour period, and

b. Daily emissions of SO_2 from the KCOB stack shall not exceed 17,143.1 pounds per calendar day.

D.6. ExxonMobil shall comply with 40 CFR 63 Subpart CC, including the miscellaneous process vent provisions in 40 CFR 63.643 as appropriate (ARM 17.8.342 and 40 CFR 63, Subpart CC).

Compliance Demonstration

D.7. ExxonMobil shall operate and maintain a COMS on the KCOB stack to monitor compliance with the KCOB opacity limitation in Section III.D.1 (ARM 17.8.105, ARM 17.8.106, and ARM 17.8.1213).

D.8. ExxonMobil shall use the COMS specified in Section III.D.7 to satisfy the compliance assurance monitoring requirements of ARM 17.8 Subchapter 15 for the Coker/KCOB Bahco Multiclones. Operation within the designated indicator ranges of <20% opacity is deemed reasonable assurance of on-going compliance with the PM limitations in Sections III.D.2 and D.3 (see the Compliance Assurance Monitoring (CAM) Plan in Appendix F of this permit) (ARM 17.8.1212).

D.9. ExxonMobil shall operate the COMS in accordance with ARM 17.8.1511. Upon detecting an opacity excursion, ExxonMobil shall restore operation of the Coker/KCOB/Bahco Multiclones as expeditiously as practicable in accordance with good air pollution control practices for minimizing emissions (ARM 17.8.1511).

D.10. Opacity monitoring, COMS operation and maintenance, and reporting shall be performed by ExxonMobil consistent with the requirements of both 40 CFR Part 51, Appendix P and 40 CFR Part 60, Appendix B, Performance Specification 1 (ARM 17.8.1213).

D.11. As required by DEQ and Section III.A.1, ExxonMobil shall perform a Method 9 test in accordance with Section III.A.2 (ARM 17.8.105, ARM 17.8.106, and ARM 17.8.1213).

D.12. In addition to the COMS, once every 5 years (within the permit term), when YELP is not operating, ExxonMobil shall perform a Method 5 test in accordance with Section III.A.2, in order to demonstrate compliance with the PM limitations in Sections III.D.2 and III.D.3. The COMS indicator range will be updated for the CAM Plan, as necessary, based on data from the Method 5 test (ARM 17.8.105, ARM 17.8.106, and ARM 17.8.1213 and ARM 17.8.1504).

D.13. Any time ExxonMobil diverts process Coker gases from YELP, ExxonMobil shall report said diversion to DEQ within 24 hours or during the next regular working day. This information shall also be included in the quarterly SO2 SIP report and shall include the period(s) of diversion, quantity of SO_2 emissions, reason for the diversion(s), and corrective measures taken to prevent reoccurrence. Compliance with this will monitor compliance with Section III.D.4 (ARM 17.8.1213).

D.14. ExxonMobil shall install, calibrate, maintain, and operate a CEMS to continuously monitor and record the concentration of SO_2 and flow rate of the flue gas discharged from the KCOB stack during periods when Coker Process Gas is not being directed to YELP. The CEMS shall be installed, certified, and operated in accordance with the applicable performance specifications set out in 40 CFR Part 60, Appendix B and (for stack flow)

Method A-1 of Attachment #1 of the SO_2 Stipulation. Compliance with the emission limitations in Section III.D.5 shall be determined using data from the CEMS and in accordance with the appropriate equation(s) in Section 2(A)(1), (8), (11), and (16) of the SO_2 Stipulation, except when CEMS data is not available as provided in Section 2(A)(16) of the Stipulation. The CEMS shall be subject to and shall meet the quality assurance and quality control requirements of 40 CFR Part 60, Appendix F and Method B-1 of Attachment #1 of the SO_2 Stipulation. The CEMS shall meet applicable quarterly data recovery rates and other provisions of the SO_2 Stipulation (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

D.15. ExxonMobil shall perform annual source testing using EPA-approved methods (40 CFR Part 60, Appendix A, Methods 1-4 and 6/6c as appropriate for this Stipulation and Exhibit A) or an equivalent method approved by DEQ and EPA, and in accordance with Section III.A.2, to certify the SO_2 emission rates in pounds per hour for the KCOB stack. The annual Relative Accuracy Test Audits (RATAs) required by Sections 6(C and D) of the Stipulation, may substitute for the annual source tests provided that the flow rate RATA and the concentration RATA are performed simultaneously, and additional calculations are made to determine and report the data in pounds per hour of SO_2 (ARM 17.8.106 and Billings/Laurel SO2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

D.16. ExxonMobil shall operate and maintain a CEMS to measure SO_2 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 SO_2 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 Billings/Laurel Area FR Vol. 73, No. 77, April 21, 2008).

D.17. ExxonMobil shall monitor compliance with the miscellaneous process vent provisions by performing the monitoring and testing required by 40 CFR 63 Subpart CC, including as specified in 40 CFR 63.644 and 645 (ARM 17.8.342 and 40 CFR 63, Subpart CC).

Recordkeeping

D.18. All source test recordkeeping shall be performed in accordance with the test method being used and Section III.A.2 (ARM 17.8.106 and ARM 17.8.1212).

D.19. Recordkeeping associated with the COMS shall be performed consistently with the requirements of both 40 CFR Part 51, Appendix P and 40 CFR Part 60, Appendix B, Performance Specification 1. In addition, ExxonMobil shall maintain records of monitoring data, monitor performance data, corrective actions taken, any written quality improvement plan required pursuant to ARM 17.8.1512 and any activities undertaken to implement a quality improvement plan, and other supporting information required to be maintained under ARM 17.8 Subchapter 15 (ARM 17.8.1212 and ARM 17.8.1513).

D.20. ExxonMobil shall keep records of any time ExxonMobil diverts process Coker gases from YELP for five years. This information shall include the period(s) of diversion, quantity of sulfur oxide emissions, reason for the diversion(s), and corrective measures taken to prevent reoccurrence (ARM 17.8.749, ARM 17.8.1212).

D.21. In accordance with the Stipulation, ExxonMobil shall record, organize, report, and archive all the data specified in Section 7(C) of the Stipulation (Appendix E of this permit) (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

D.22. ExxonMobil shall comply with the recordkeeping requirements for miscellaneous process vent provisions in accordance with 40 CFR 63 Subpart CC (ARM 17.8.342 and 40 CFR 63, Subpart CC).

Reporting

D.23. Any compliance source test report(s) shall be submitted in accordance with Section III.A.2 (ARM 17.8.106 and ARM 17.8.1212).

D.24. ExxonMobil shall submit COMS data reports to DEQ quarterly. In addition, ExxonMobil shall report to DEQ, on a calendar quarterly basis, opacity results from the COMS, which exceed the 20% provided in ARM 17.8.304(2) (ARM 17.8.1212).

D.25. Any time ExxonMobil diverts Coker Process Gas from YELP, ExxonMobil shall report said diversion to DEQ within 24 hours or during the next regular working day. This information shall also be included in a quarterly report and shall include the period(s) of diversion, hours that Coker Process Gas was exhausted through the KCOB, the quantity of SO_2 emissions, reason for the diversion(s), and corrective measures taken to prevent reoccurrence (ARM 17.8.749).

D.26. In accordance with Section 7 of the Stipulation (Appendix E of this permit), ExxonMobil shall submit quarterly SO_2 SIP reports within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to DEQ's Permitting and Compliance office in Helena and the Billings Regional Office. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written or hard copy data summary report. The quarterly reports shall also include the report on the COMS for the Coker CO Boiler stack (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

D.27. In accordance with Section (f)(5)(i) of the FIP, ExxonMobil shall submit quarterly reports within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to the Air Program Contact at the EPA Montana Operations Office. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written or hard copy data summary report (Federal Implementation Plan for the Billings/Laurel Area FR Vol. 73, No. 77, April 21, 2008).

D.28. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1213)

D.29. The semiannual compliance monitoring reports shall provide a summary of any required monitoring, with all instances of deviations from permit requirements clearly identified. The report shall include the following (ARM 17.8.1212):

a. A summary of the results of any required reference method tests performed during the reporting period;

b. Reference to dates that quarterly reports were submitted

c. Summary of compliance with the reporting requirements of 40 CFR 63 Subpart CC during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 63 Subpart CC.

E. EU04 – Catalytic Reforming Unit (POFO – Powerforming Unit)
EU04b: Catalytic Reforming Unit Process Vent

Condition(s)	Pollutant/Parameters	Permit Limits	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
E.1, E.5, E.6, E.7, E.8, E.9, E.10	Catalytic Reforming Unit	40 CFR 63, Subpart UUU	40 CFR 63 Subpart UUU	40 CFR 63 Subpart UUU	Semiannually and 40 CFR 63 Subpart UUU
E.2, E.4, E.5, E.6, E.7, E.8, E.9, E.10	Catalytic Reforming Unit - Organic HAP	Vent emissions to RFG system when pressure > 5 psig	Operation, Maintenance and Monitoring Plan (OMMP)	During unit depressurization and catalyst purging	Semiannually
E.3, E.4, E.5, E.6, E.7, E.8, E.9, E.10	Catalytic Reforming Unit - Inorganic HAP	<30 ppm HCl dry corrected @ 3% O_2 (daily average)	OMMP	During each coke burn-off and catalyst rejuvenation cycle	Semiannually

Conditions

E.1. ExxonMobil shall comply with all applicable requirements of 40 CFR 63 Subpart UUU – NESHAPs for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. These regulations shall apply to the Powerforming Unit and any other equipment, as appropriate (ARM 17.8.342 and 40 CFR 63 Subpart UUU).

E.2. At all times except startup, shutdown, and malfunction, ExxonMobil shall meet applicable requirements for organic HAP emissions from catalytic reforming units, set out under 40 CFR 63 Subpart UUU. During unit depressurization and catalyst purging, the catalytic reforming unit vent emissions must be routed to the RFG system until unit pressure is less than or equal to 5 psig (ARM 17.8.342 and 40 CFR 63 Subpart UUU).

E.3. At all times except startup, shutdown, and malfunction, ExxonMobil shall meet applicable requirements for inorganic HAP emissions from catalytic reforming units, set out under 40 CFR 63 Subpart UUU. During each coke burn off and catalyst rejuvenation cycle, ExxonMobil shall operate an internal caustic scrubber to meet the applicable HCl limit of 30 ppmvd @ 3% O_2 on a daily average and catalytic reforming unit operation limits set out under 40 CFR 63.1567 (ARM 17.8.342 and 40 CFR 63, Subpart UUU).

E.4. ExxonMobil shall prepare an OMMP according to the requirements in 40 CFR 63.1574 and operate at all times according to the procedures in the plan (ARM 17.8.342, 40 CFR 63 Subpart UUU).

Compliance Demonstration

E.5. ExxonMobil shall conduct all monitoring and testing as required by 40 CFR 63 Subpart UUU, including maintaining records to document conformance with procedures in ExxonMobil's required OMMP (ARM 17.8.342 and 40 CFR 63 Subpart UUU).

Recordkeeping

E.6. All source test recordkeeping shall be performed in accordance with the test method being used and Section III.A.2 (ARM 17.8.106 and ARM 17.8.1212).

E.7. ExxonMobil shall conduct all applicable recordkeeping requirements in accordance with 40 CFR 63 Subpart UUU (ARM 17.8.342 and 40 CFR 63 Subpart UUU).

Reporting

E.8. Any compliance source test report(s) shall be submitted in accordance with Section III.A.2 (ARM 17.8.106).

E.9. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1213)

E.10. The semiannual compliance monitoring reports shall provide a summary of any required monitoring, with all instances of deviations from permit requirements clearly identified. The report shall include the following (ARM 17.8.1212):

a. A summary of the results of any reference method tests performed during the reporting period;

b. Summary of compliance with the reporting requirements of 40 CFR 63 Subpart UUU during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 63 Subpart UUU;

F. EU09 – FCCU – Catalytic Cracking Unit

EU09a: CCOB - FCC CO Boiler
EU09b: CCOB Bypass Line

Condition(s)	Pollutant/Parameters	Permit Limits	Compliance Demonstration Method	Frequency	Reporting Requirements
F.1, F.16, F.17, F.18, F.29, F.34, F.35, F.37, F.38	Opacity – FCCU Catalyst Regenerator (through CCOB Stack)	30% (except one 6-minute period in each hour)	COMS	Ongoing	Quarterly
			Method 9	As required by DEQ and Section III.A.1	Semiannually and Section III.A.2
F.2, F.16, F.17, F.18, F.29, F.34, F.35, F.37, F.38	Opacity – CCOB (when FCCU Catalyst Regenerator is down)	40%/60% for Soot Blowing	COMS	Ongoing	Quarterly
			Method 9	As required by DEQ and Section III.A.1	Semiannually and Section III.A.2
F.3, F.19, F.22, F.31, F.37, F.38	FCCU Catalyst Regenerator (PM, CO and opacity)	40 CFR 60 Subpart J	40 CFR 60 Subpart J	40 CFR 60 Subpart J	Semiannually and 40 CFR 60 Subpart J
F.4, F.15, F.20, F.32, F.37, F.38	FCCU Catalyst Regenerator (PM, CO, HAPs and opacity)	40 CFR 63 Subpart UUU	40 CFR 63 Subpart UUU	40 CFR 63 Subpart UUU	Semiannually and 40 CFR 63 Subpart UUU
F.5, F.21, F.23, F.29, F.34, F.37, F.38	PM – FCC Unit	1.0 lb/1000 lb coke burned (calendar daily average)	Method 5F	Annually or as approved by the Administrator	Semiannually and Section III.A.2
F.6, F.16, F.24, F.25, F.26, F.27, F.29, F.30, F.34, F.35, F.37, F.38	SO_2 -- ExxonMobil Coker Process Gas going to YELP and CCOB Stack	Lb/day limit (Table 1a)	SO_2 CEMS	Ongoing	Quarterly
			Method 6/6C	Annually	Semiannually and Section III.A.2
F.6, F.16, F.24, F.25, F.26, F.27, F.29, F.30, F.34, F.35, F.37, F.38	SO_2 -- ExxonMobil Coker Process Gas going to YELP and CCOB Stack	Lb/day limit (Table 1b)	SO_2 CEMS	Ongoing	Quarterly
			Method 6/6C	Annually	Semiannually and Section III.A.2
F.7, F.16, F.24, F.25, F.26, F.27, F.29, F.30, F.34, F.35, F.37, F.38	SO_2 -- ExxonMobil Coker Process Gas not going to YELP and CCOB Stack	Lb/day limit (Table 2a and 2b)	SO_2 CEMS	Ongoing	Quarterly
			Method6/6C	Annually	Semiannually and Section III.A.2
F.8, F.16, F.24, F.34, F.35, F.37, F.38	SWSOH	Burning the SWSOH in the CCOB or the Flare	SO_2 CEMS	Ongoing	Quarterly

Condition(s)	Pollutant/Parameters	Permit Limits	Compliance Demonstration Method	Frequency	Reporting Requirements
F.9, F.19, F.22, F.31, F.37, F.38	Treat or reroute SWS feed with hydrogen peroxide	40 CFR 60 Subpart J	40 CFR 60 Subpart J	40 CFR 60 Subpart J	Semiannually and 40 CFR 60 Subpart J
F.10, F.16, F.37, F.38	Operate the FCCU in a Full Burn Operation and implement an SO_2 emissions control program	FCCU Full Burn Operation and SO_2 Reduction	SO_2 CEMS SIP/FIP	Ongoing	Quarterly
F.11, F.16, F.19, F.22, F.23, F.31, F.37, F.38	FCCU: CO	500 ppmvd CO corrected to 0% O_2 on a 1-hour average basis	CEMS	Ongoing	Semiannually and 40 CFR 60 Subpart J
F.12, F.16, F.23, F.28, F.33, F.37, F.38	FCCU: NO_X	30 ppmvd at 0% O_2 on a 365-day rolling average basis 80 ppmvd at 0% O_2 on a 7-day rolling average basis	CEMS	Ongoing	Quarterly
F.13, F.20, F.32, F.37, F.38	40 CFR 63 Subpart UUU	metal HAP emissions	40 CFR 63 Subpart UUU	40 CFR 63 Subpart UUUU	Semiannually and 40 CFR 63 Subpart UUU
F.14, F.20, F.32, F.37, F.38	40 CFR 63 Subpart UUU	organic HAP emissions	40 CFR 63 Subpart UUU	40 CFR 63 Subpart UUUU	Semiannually and 40 CFR 63 Subpart UUU
F.15, F.20, F.32, F.37, F.38	40 CFR 63 Subpart UUU	operation, maintenance, and monitoring plan	40 CFR 63 Subpart UUU	40 CFR 63 Subpart UUUU	Semiannually and 40 CFR 63 Subpart UUU

Conditions

F.1. Except during periods of startup, shutdown, or malfunction, as defined by 40 CFR 60.2, ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere, from the FCCU catalyst regenerator, measured at the CCOB stack, gases that exhibit greater than 30% opacity, except for one 6-minute average opacity reading in any one-hour period. At all times, including periods of startup, shutdown, and malfunction, ExxonMobil shall, to the extent practicable, maintain and operate each FCCU catalyst regenerator and any associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60, Subpart J).

F.2. When the FCCU catalyst regenerator is down, ExxonMobil shall not cause or authorize emissions to be discharged into the outdoor atmosphere, from the CCOB that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes. During the building of new fires, cleaning of grates, or soot blowing, the provisions of ARM 17.8.304(1) and (2) shall apply, except that a maximum average opacity of 60% is permissible for not more than one 4-minute period in any 60 consecutive minutes. Such a 4-minute period means any 4 consecutive minutes (ARM 17.8.304(1) and ARM 17.8.304(3)).

F.3. The FCCU catalyst regenerator shall comply with the emission limitations in 40 CFR 60, Subpart J for particulate matter, carbon monoxide, and opacity (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60 Subpart J). ExxonMobil shall ensure the each FCCU catalyst regenerator complies with the applicable emissions limitations imposed by NSPS J except during periods of startup, shutdown, or malfunction as defined by 40 CFR 60.2. At all times, including startup, shutdown, and malfunctions, ExxonMobil shall, to the extent practicable, maintain and operate each FCCU catalyst regenerator and any associated air pollution control equipment in a manner consistent with good air pollution control practice and minimize emissions (ARM 17.8.749, Consent Decree Paragraph 43.e).

F.4. ExxonMobil shall comply with all the applicable requirements in 40 CFR 63, Subpart UUU– National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units. The FCC Regenerator is subject to the Subpart UUU requirements for PM, CO, HAPs and opacity (ARM 17.8.342 and 40 CFR 63 Subpart UUU).

F.5. ExxonMobil shall install and operate a third-stage cyclone on the FCC Unit, and take any additional steps necessary, in order to comply with a PM emission limit of 1.0 lb of PM per 1,000 lb of coke burned (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart J). PM emissions (i) caused by or attributed to the startup and shutdown of the FCCU and/or (ii) during periods of malfunction of the FCCU or malfunction of third-stage cyclone will not be used in determining compliance with the PM emission limit provided that during such periods ExxonMobil implements good air pollution control practices to minimize PM emissions (ARM 17.8.749, Consent Decree Paragraph 36).

F.6. The following emission limitations shall apply to the CCOB stack whenever YELP is receiving ExxonMobil Coker process gas or whenever the ExxonMobil Coker unit is not operating (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

a. SO_2 3-hour emissions from the CCOB stack shall not exceed those values set forth in the following Table 1a. The 3-hour SO_2 emission limitations from the CCOB stack shall be determined by the 3-hour average FCC fresh feed rate, expressed in thousands of barrels per day (kBD), rounded up to the nearest whole barrel.

Table 1a

3-Hour Average FCC Fresh Feed Rate (kBD)	3-Hour SO_2 Emission Limit (lb of SO_2 per 3-hours)
less than 12.999	5886.8
13.000 to 13.999	6052.0

14.000 to 14.999	6103.7
15.000 to 15.999	6130.6
16.000 to 16.999	6221.8
Greater than 17.000	6280.4

b. Daily emissions of SO_2 from the CCOB stack shall not exceed those values set forth in the following Table 1b. The daily SO_2 emission limitations from the CCOB stack shall be determined by the daily average FCC fresh feed rate, expressed in thousands of barrels per day (kBD), rounded up to the nearest whole barrel.

Table 1b

Daily Average FCC Fresh Feed Rate (kBD)	Daily SO_2 Emission Limit (lb of SO_2 per Calendar Day)
less than 12.999	47,094.3
13.000 to 13.999	48,416.3
14.000 to 14.999	48,829.7
15.000 to 15.999	49,044.9
16.000 to 16.999	49,774.5
greater than 17.000	50,243.1

F.7. The following emission limitations shall apply to CCOB stack whenever YELP is not receiving ExxonMobil Coker process gas and the ExxonMobil Coker unit is operating (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

a. SO_2 3-hour emissions from the CCOB stack shall not exceed those values set forth in the following Table 2a. The 3-hour SO_2 emission limitations from the CCOB stack shall be determined by the 3-hour average FCC fresh feed rate expressed in thousands of barrels per day (kBD), rounded up to the nearest whole barrel.

Table 2a

3-Hour Average FCC Fresh Feed Rate (kBD)	3-Hour SO_2 Emission Limit (lb of SO_2 per 3-hours)
less than 12.999	5231.5
13.000 to 13.999	5485.3
14.000 to 14.999	5743.7
15.000 to 15.999	5966.6
16.000 to 16.999	6190.4
Greater than 17.000	6416.4

b. Daily Emissions of SO_2 from the CCOB stack shall not exceed those values set forth in the following Table 2b. The daily SO_2 emission limitations from the CCOB stack shall be determined by the daily average FCC fresh feed rate expressed in thousands of barrels per day (kBD), rounded up to the nearest whole barrel.

Table 2b

Daily Average FCC Fresh Feed Rate (kBD)	Daily SO_2 Emission Limit (lb of SO_2 per Calendar Day)
less than 12.999	41,852.1
13.000 to 13.999	43,882.7
14.000 to 14.999	45,949.5
15.000 to 15.999	47,732.5
16.000 to 16.999	49,523.1
greater than 17.000	51,330.8

F.8. ExxonMobil shall burn the SWSOH in the CCOB and exhaust those emissions through the CCOB stack, except that the SWSOH may be burned in the F-1 Crude Furnace (and exhausted through the F-2 Crude/Vacuum Heater stack) or in the Flare during periods when the CCOB is unable to burn the SWSOH, provided that:

a. Such periods do not exceed 55 days per calendar year and 65 days for any 2 consecutive calendar years, and

b. During such periods the SWS system is operating in a two-tower configuration.

(Board Order signed on June 12, 1998, and subsequent revisions of March 17, 2000; this requirement is "State Only").

F.9. ExxonMobil shall meet 40 CFR 60 Subpart J requirements for the Sour Water Stripping Unit (SWS) T-23 Overhead Gas by rerouting or treating SWS feed with hydrogen peroxide (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart J).

F.10. ExxonMobil shall comply with the following SO_2 emission limits on the FCCU (ARM 17.8.749 and Consent Decree Paragraph 142):

a. 177.3ppm$_{vd}$ at 0% O_2 on a 365-day rolling average basis, applicable at all times (including during startup, shutdown, and malfunction) that the FCCU is operating. For days in which the FCCU is not operating, no SO_2 values shall be used in the averages, and those periods shall be skipped in determining the 365-day averages

b. 300.0 ppm$_{vd}$ at 0% O_2 on a 7-day rolling average basis. SO_2 emissions (i) caused by or attributed to the startup, shutdown, or malfunction of the FCCU and/or (ii) during periods of malfunction of the SO_2 reducing catalyst additive system will not be used in determining compliance with the short-term (7-day) SO_2 emission limit provided that during such periods ExxonMobil implements good air pollution control practices to minimize SO_2 emissions

F.11. ExxonMobil shall comply with 500 ppm$_{vd}$ CO corrected to 0% O_2 on a 1-hour average basis on the FCCU (ARM 17.8.749).

CO emissions (i) caused by or attributed to the startup, shutdown, or malfunction of the FCCU and/or (ii) during periods of malfunction of the FCCU's CO control system will not be used in determining compliance with the short-term (1-hr) CO emission limit provided that during such periods ExxonMobil implements good air pollution control practices to minimize CO emissions (ARM 17.8.749, Consent Decree Paragraph 41).

F.12. ExxonMobil shall comply with the following NO_x emission limits on the FCCU;

a. 30 ppm$_{vd}$ at 0% O_2 on a 365-day rolling average basis, applicable at all times (including during startup, shutdown, and malfunction) that the FCCU is operating. For days in which the FCCU is not operating, no NO_X values shall be used in the averages, and those periods shall be skipped in determining the 365-day averages (ARM 17.8.749 and October 9, 2014, EPA Limit Approval Letter); and

b. 80 ppm$_{vd}$ at 0% O_2 on a 7-day rolling average basis, other than FCCU NOx emissions during a period of natural gas curtailment when fuel oil is burned. During such period of natural gas curtailment, ExxonMobil shall comply with an alternate short-term NO_X limit of 120 ppm$_{vd}$ at 0% O_2 on a 24-hour rolling average basis. NO_X emissions (i) caused by or attributed to the startup, shutdown, or malfunction of the FCCU and/or (ii) during periods of malfunction of the selective catalytic reduction unit (SCR) will not be used in determining compliance with the short-term (7-day) NO_X emission limit provided that during such periods ExxonMobil implements good air pollution control practices to minimize NO_X emissions (ARM 17.8.749, Consent Decree Paragraph 20).

F.13. ExxonMobil shall meet the metal HAP emissions limitations on the FCCU under 40 CFR 63 Subpart UUU by meeting the PM emission limitations for the FCCU set out at 40 CFR 60 Subpart J. The metal HAP emissions limitations shall always apply except startup, shutdown and malfunction, or during periods of planned maintenance preapproved by DEQ according to the requirements in 40 CFR 63 Subpart UUU (ARM 17.8.342 and 40 CFR 63, Subpart UUU).

Pursuant to 40 CFR 63.1564(a)(5), ExxonMobil must comply with one of the following options during periods of startup, shutdown, and hot standby on the FCC Unit:

a. Compliance with the operating or emission limit requirements in 40 CFR 63.1564(a)(1) and (2), or

b. Maintaining the inlet velocity to the primary internal cyclones of the catalytic cracking unit catalyst regenerator at or above 20 feet per second.

F.14. ExxonMobil shall meet the organic HAP emissions limitations on the FCCU under 40 CFR 63 Subpart UUU by meeting the CO emission limitations for catalytic cracking units under 40 CFR 60 Subpart J. The organic HAP emission limitations shall always apply except startup, shutdown and malfunction, or during periods of planned maintenance preapproved by DEQ according to the requirements in 40 CFR 63 Subpart UUU (ARM 17.8.342 and 40 CFR 63, Subpart UUU).

Pursuant to 40 CFR 63.1565(a)(5), ExxonMobil must comply with one of the following options during periods of startup, shutdown, and hot standby on the FCC Unit:

a. Compliance with the operating or emission limit requirements in 40 CFR 63.1565(a)(1) and (2), or

b. Maintaining the oxygen (O_2) concentration in the exhaust gas from your catalyst

F.15. Pursuant to 40 CFR 63.1564(a)(3) and 40 CFR 63.1565(a)(3), ExxonMobil shall prepare an operation, maintenance, and monitoring plan (OMMP) according to the requirements in 40 CFR 63 Subpart UUU and operate at all times according to the procedures in the plan (ARM 17.8.342 and 40 CFR 63 Subpart UUU).

Compliance Demonstration

F.16. ExxonMobil shall install and operate the following CEMS/COMS/Continuous Emission Rate Monitor System (CERMS) on the CCOB stack. Emission monitoring shall be performed in accordance with 40 CFR 60 Appendix A, 40 CFR 60 Appendix B (as would be applicable), and the Quality Assurance Procedures in 40 CFR 60 Appendix F:

a. Opacity (ARM 17.8.749; ARM 17.8.340 and 40 CFR 60 Subpart J; ARM 17.8.342 and 40 CFR 63 Subpart UUU; and 40 CFR Part 51 Appendix P);

b. SO_2 (ARM 17.8.749 and Billings/Laurel SO_2 Control Plan approved into the SIP by EPA on May 2, 2002, and May 22, 2003);

c. CO (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60 Subpart J);

d. NO_x (ARM 17.8.749);

e. O_2 (ARM 17.8.749); and

f. Volumetric Flow (Billings/Laurel SO_2 Control Plan approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

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

F.17. Compliance with opacity limits in Sections III.F.1 and III.F.2 shall be monitored using data from the COMS. The COMS shall meet applicable provisions of 40 CFR 60.105(a)(1) and 60.13. Opacity monitoring, COMS operation and maintenance, and reporting shall be performed by ExxonMobil consistent with the requirements of both 40 CFR Part 51, Appendix P and 40 CFR Part 60, Appendix B, Performance Specification 1, and the Quality Assurance Procedures in 40 CFR 60 Appendix F (Procedure 3) (ARM 17.8.1213, ARM 17.8.103(d) and 40 CFR Part 51, Appendix P).

F.18. In addition to the COMS, as required by DEQ and Section III.A.1, compliance with the opacity limits may also be monitored via EPA Reference Method 9 performed by a certified observer in accordance with Section III.A.2 (ARM 17.8.105, ARM 17.8.106, and ARM 17.8.1213).

F.19. ExxonMobil shall conduct all monitoring and testing as required by 40 CFR 60 Subpart J, Standards of Performance for Petroleum Refineries. These regulations shall apply to the FCCU Catalyst Regenerator and any other equipment, as appropriate (ARM 17.8.1213, ARM 17.8.340 and 40 CFR 60 Subpart J).

F.20. ExxonMobil shall conduct all monitoring and testing as required by 40 CFR 63 Subpart UUU, including maintaining records to document conformance with procedures in ExxonMobil's required OMMP (ARM 17.8.342 and 40 CFR 63, Subpart UUU).

F.21. ExxonMobil shall perform a Method 5F test on the FCCU annually, or according to another schedule as may be approved by the Administrator, in writing, to monitor compliance with the PM limitation found in Section III.F.5 (ARM 17.8.749, ARM 17.8.105, ARM 17.8.340, and 40 CFR 60 Subpart J).

F.22. ExxonMobil shall install, operate, and maintain the applicable CEMS or develop an AMP as required by 40 CFR 60 Subparts A & J. Emission monitoring shall comply with all applicable provisions of 40 CFR 60.7 through 60.13; 40 CFR Part 60 Appendix A; 40 CFR Part 60 Appendix B (Performance Specifications 1, 2, 3, 4, 6, and 7); and 40 CFR Part 60 Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.1213 and 40 CFR 60 Subpart J).

F.23. Emissions (i) caused by or attributable to the startup, shutdown, or malfunction of an FCC Unit and/or (ii) during periods of malfunction of the relevant FCC Unit's Control System(s) will not be used in monitoring compliance with the PM limits or short-term (7-day for NO_x, 7-day for SO_2, or 1-hour for CO) limits, provided that during such periods ExxonMobil implements good air pollution control practices to minimize said emissions. NO_x, SO_2, and CO emissions during any such period of startup, shutdown, or malfunction shall either be: (i) monitored with CEMS; or (ii) monitored in accordance with an alternative monitoring plan approved by the EPA if it is necessary to bypass the FCC Unit's main stack during the period of startup, shutdown, or malfunction (ARM 17.8.749, Consent Decree Paragraph 20, 31, 36, and 41).

F.24. ExxonMobil shall operate and maintain a continuous flow rate meter to determine the fresh feed rate to the FCC reactor. In addition, ExxonMobil shall maintain a spare parts inventory (at a minimum, a spare transducer) that together with the FCC-specific Programmable Logic Controller (PLC) module is capable of functioning as a back-up continuous flow rate meter to measure the fresh feed rate to the FCC reactor. The back-up continuous flow rate meter shall be a completely redundant system capable of obtaining flow rate data in the event of the failure of the primary continuous flow rate meter required by this section. The back-up system may rely upon the in-pipe orifice plate and associated mechanical connections that are components of the primary continuous flow rate meter up to, but not including, the transducer. Accuracy determinations for the FCC Fresh Feed Rate Meter shall be required at least once every 48 months or more frequently as routine refinery turn-arounds allow (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

F.25. If continuous flow rate meter data (used to determine the FCC fresh feed rate) is unavailable, the emission limitation shall be determined using a substitute hourly average fresh feed rate determined in accordance with the requirements of Section 2(A)(15) of the SO_2 Stipulation (Appendix E of this permit) (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

F.26. ExxonMobil shall operate and maintain a CEMS to measure SO_2 concentrations and a CERMS to measure stack gas flow rate of the flue gas discharged from the CCOB stack. Compliance with the emission limitations contained in Sections III.F.6 and III.F.7 shall be monitored using data from the CEMS required by Section 6(B)(1) and (2) of the Stipulation (Appendix E of this permit) and in accordance with the appropriate equation(s) in Section 2(A)(1), (8), (11), and (16) of the Stipulation, except when CEMS data is not available as provided in Section 2(A)(16) of the Stipulation.

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

Although the CEMS data is the method of monitoring compliance on a continuous basis, the data from the testing required by Section 5(A) or Section 6(C and D) of the Stipulation shall also be used to demonstrate compliance. Notwithstanding the fact that fuel gas combustion emissions from the CCOB are measured by the fuel gas system CEMS and counted against the emission limitations contained in Section 3 (A)(1) and (B)(2) of the Stipulation, such emissions are also measured by the CCOB CEMS and shall be counted against the emission limitations contained in Section 3(A)(3) and (B)(4) of the Stipulation (ARM 17.8.749 and Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

F.27. In order to accurately monitor the SO_2 emission rates in pounds per hour for the CCOB stack, ExxonMobil shall perform annual source testing using EPA-approved methods (40 CFR Part 60 Appendix A, Methods 1-4 and 6/6c as appropriate for this Stipulation and Exhibit A) or an equivalent method approved by DEQ and EPA, and in accordance with Section III.A.1 (ARM 17.8.106). The annual RATAs required by Sections 6(C and D) of the Stipulation (Appendix E of this permit) may substitute for the annual source tests provided that the flow rate RATA and the concentration RATA are performed simultaneously and additional calculations are made to determine and report the data in pounds per hour of SO_2 (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

F.28. The FCCU stack shall be equipped and operated with CEMS to measure NO_x. Emission monitoring shall be performed in accordance with 40 CFR Part 60 Appendix B, Performance Specifications 2 and 3; and 40 CFR Part 60 Appendix F – Quality Assurance Procedures (ARM 17.8.1211).

Recordkeeping

F.29. ExxonMobil shall perform all source test recordkeeping in accordance with the appropriate test method and Section III.A.2. ExxonMobil shall maintain COMS data and submit the reports to DEQ quarterly (ARM 17.8.1212).

F.30. In accordance with the Stipulation, ExxonMobil shall record, organize, report, and archive all the data specified in Section 7(C) of the Stipulation (Appendix E of this permit) (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

F.31. ExxonMobil shall conduct all applicable recordkeeping requirements in accordance with 40 CFR 60 Subpart J (ARM 17.8.1212, ARM 17.8.340 and 40 CFR 60 Subpart J).

F.32. ExxonMobil shall conduct all applicable recordkeeping requirements in accordance with 40 CFR 63 Subpart UUU (ARM 17.8.342 and 40 CFR 63, Subpart UUU).

F.33. ExxonMobil shall conduct all applicable recordkeeping for the FCCU NO_x CEMS in accordance with 40 CFR Part 60 Appendix B, Performance Specifications 2 and 3; and Appendix F – Quality Assurance Procedures (ARM 17.8.1211).

Reporting

F.34. Any compliance source test report(s) shall be submitted in accordance with Section III.A.2 (ARM 17.8.106).

F.35. In accordance with Section 7 of the Stipulation (Appendix E of this permit), ExxonMobil shall submit quarterly reports within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to DEQ's Permitting and Compliance office in Helena and the Billings Regional Office. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written or hard copy data summary report. The quarterly reports shall also include the report on the COMS for the CCOB Stack (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

F.36. ExxonMobil shall report quarterly the daily NO_x rolling 365-day average and the maximum NO_x 7-day rolling average per quarter for the FCCU stack. These reports shall also include NO_x CEMS quarterly performance (excess emissions and monitor downtime) and 40 CFR Part 60 Appendix F – Quality Assurance Procedures provisions. FCCU quarterly NO_x reporting shall be submitted in conjunction with the SO_2 SIP emissions and CEMS/CERMS reporting periods (ARM 17.8.1212).

F.37. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1213).

F.38. The semiannual compliance monitoring reports shall provide a summary of any required monitoring, with all instances of deviations from permit requirements clearly identified. The report shall include the following (ARM 17.8.1212):

a. A summary of the results of any reference method tests performed during the reporting period;

b. Reference to dates that quarterly reports were made;

c. Summary of compliance with the reporting requirements of 40 CFR 60 Subpart J during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 60 Subpart J;

d. Summary of compliance with the reporting requirements of 40 CFR 63 Subpart UUU during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 63 Subpart UUU.

G. EU14 –Oil Movements & Utilities (OM&U)

EU14a: Flare - Flare or Turnaround Flare
EU14c: Flare Seal Drum (Group I Miscellaneous Process Vents)

Condition(s)	Pollutant/Parameters	Permit Limits	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
G.1, G.11, G.20, G.21, G.29, G.33, G.34	H_2S: Flare	Burn SWSOH in CCOB, F-1 Crude Furnace or Flare	Operate Sensor on the Valve and Perform Recordkeeping	Whenever Valve is Opened	Quarterly
G.2, G.17, G.18, G.26, G.30, G.31, G.33, G.34	SO_2 Flare FIP	150 lb/3-hr period	Reporting	As required by FIP	Quarterly & as necessary
G.3, G.14, G.33, G.34	Organic HAPs	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannually and 40 CFR 63 Subpart CC
G.4, G.13, G.14, G.32, G.33, G.34	Flare and Turnaround Flare	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannually and 40 CFR 63 Subpart CC
G.5, G.13, G.22, G.32, G.33, G.34	Misc. Process Vents	As Required by 40 CFR 63.643	As Required	As required by 40 CFR 63.644 & 645	Semiannually and as required by 40 CFR 63.654

Condition(s)	Pollutant/Parameters	Permit Limits	Compliance Demonstration Method	Frequency	Reporting Requirements
G.6, G.15, G.23, G.33, G.34	Air Pollution Control Practices - Flare and Turnaround Flare	Good Air Pollution Control Practices as Outlined in 40 CFR 60.11(d)	Appropriate Operation and Perform Recordkeeping	Ongoing	Semiannually
G.8, G.16, G.25, G.33, G.34	Flare and Turnaround Flare	Meet NSPS Subparts A and Ja	40 CFR 60 Subparts A and Ja	40 CFR 60 Subparts A and Ja	Semiannually and 40 CFR 60 Subpart Ja
G.9, G.19, G.33, G.34	Maintenance of flare gas recovery system	reasonable measures to minimize emissions	Consent Decree	Ongoing	Semiannually and as needed
G.10, G.19, G.27, G.33, G.34	Root Cause Failure Analysis	within 45 days of the end of the event	Appendix H	within 45 days of the end of the event	Consent Decree

Conditions

G.1. ExxonMobil shall burn the SWSOH in the F-1 Crude Furnace or in the flare during periods when the CCOB is unable to burn the SWSOH, provided that:

a. Such periods do not exceed 55 days per calendar year and 65 days for any 2 consecutive calendar years, and

b. During such periods the sour water stripper system is operating in a two-tower configuration.

(Board Order signed on June 12, 1998, and subsequent revisions of March 17, 2000; this requirement is "State Only").

G.2. 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).

G.3. ExxonMobil shall reduce emissions of organic HAPs from process vent emissions by using a flare that operates with a continuous pilot flame and meets applicable control device requirements of 40 CFR 60.18, 40 CFR 63.11, and 40 CFR 63 Subpart CC (ARM 17.8.340 and 40 CFR 60, Subpart J, and ARM 17.8.342, 40 CFR 63.11, and 40 CFR 63 Subpart CC).

G.4. ExxonMobil shall comply with the flare control device provisions of 40 CFR 63 Subpart CC (ARM 17.8.342 and 40 CFR 63 Subparts A and CC).

G.5. ExxonMobil shall comply with the miscellaneous process vent provisions in 40 CFR 63 Subpart CC (including those for miscellaneous maintenance vents under 40 CFR 63.643(c)) (ARM 17.8.342 and 40 CFR 63 Subparts A and CC).

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

G.7. The main and turnaround flares shall meet the requirements of 40 CFR 60 Subparts A and J for fuel gas combustion devices (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart J).

G.8. ExxonMobil shall comply with all applicable requirements of 40 CFR 60 Subparts A and Ja, including as applicable to the main and turnaround flares (ARM 17.8.340 and 40 CFR 60 Subpart Ja).

G.9. ExxonMobil shall take all reasonable measures to minimize emissions while periodic maintenance is being performed on the flare gas recovery system. Periodic maintenance will be required for properly designed and operated flare gas recovery systems (Consent Decree paragraph 76).

G.10. 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 Analysis as prescribed in Appendix H (Consent Decree paragraphs 79, 80, 81).

Compliance Demonstration

G.11. ExxonMobil shall operate an electronic sensor on the valve that supplies SWSOH to the F-1 Crude Furnace and/or Flare. The electronic sensor shall be electronically integrated with the Data Acquisition System (DAS) to ensure that each time the valve is opened (SWSOH to Flare) the DAS automatically records the date and time that the valve is opened and the length of time the SWSOH are directed to the Flare (Board Order signed on June 12, 1998, and subsequent revisions of March 17, 2000; this requirement is "State Only").

G.12. ExxonMobil shall conduct all monitoring and testing as required by 40 CFR 60 Subpart A (General Provisions) and Subpart J (Standards of Performance for Petroleum Refineries). These regulations shall apply to the main and turnaround flares and any other equipment, as applicable (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60, Subparts A and J). ExxonMobil shall install and operate a continuous monitor pursuant to 40 CFR 60.105(a)(4) or with a parametric monitoring system approved by EPA as an alternative monitoring system under 40 CFR 60.13(i) (ARM 17.8.749, ARM 17.8.340, 40 CFR 60 Subpart J).

G.13. Compliance with the miscellaneous process vent provisions shall be monitored as required by 40 CFR 63 Subpart CC, including in accordance with 40 CFR 63.643, 63.644, 63.645, and 63.655, as appropriate (including those for miscellaneous maintenance vents under 40 CFR 63.643). (ARM 17.8.342 and 40 CFR 63, Subparts A and CC).

G.14. ExxonMobil shall install a device (including but not limited to a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of continuously detecting the presence of a pilot flame for the flare and comply with 40 CFR 63.670 and 63.671 (ARM 17.8.342 and 40 CFR 63 Subpart CC).

G.15. ExxonMobil shall demonstrate compliance with Section III.G.6 through implementation of good air pollution control practices pursuant to the requirements outlined in 40 CFR

60.11(d) and as required by the Consent Decree, Paragraph 70 (ARM 17.8.749, Consent Decree Paragraph 70).

G.16. ExxonMobil shall conduct all monitoring and testing as required by 40 CFR 60 Subpart A and Ja. These regulations shall apply to the main and turnaround flares, and any other equipment as applicable (ARM 17.8.340 and 40 CFR 60 Subpart A and Ja).

G.17. ExxonMobil shall operate a continuous flow monitoring system and a flare concentration monitoring system for the Flare and Turnaround Flare in accordance with the FIP (ARM 17.8.1213, Federal Implementation Plan for the Billings/Laurel Area FR Vol. 73, No. 77, April 21, 2008):

a. CEM systems shall follow 40 CFR 60, Appendix B, Performance Specification 5 and Appendix F

b. ExxonMobil shall notify the EPA within 25 working days prior to the actual testing for an annual RATA on a CEM

c. The volumetric flow monitor(s) shall be calibrated annually according to manufacturer's specifications

d. Thirty days prior to installing the monitoring systems, ExxonMobil shall submit to EPA for review a QA/QC plan for each monitoring system

G.18. For SSM flare events that exceed the limit contained in G.2, ExxonMobil shall follow the Affirmative Defense provisions contained in the FIP for civil penalty relief (Federal Implementation Plan for the Billings/Laurel Area FR Vol. 73, No. 77, April 21, 2008).

G.19. ExxonMobil shall follow Appendix H when conducting a Root Cause Failure Analysis for each acid gas flaring event and hydrocarbon flaring event (ARM 17.8.1212).

Recordkeeping

G.20. Whenever the valve that supplies SWSOH to the Flare is opened, ExxonMobil shall log the date and time and the reasons for such action (Board Order signed on June 12, 1998, and subsequent revisions of March 17, 2000; this requirement is "State Only").

G.21. ExxonMobil shall maintain a record of all flaring events other than de minimis activities, including reviewer's initials (Board Order signed on June 12, 1998, and subsequent revisions of March 17, 2000; this requirement is "State Only," and ARM 17.8.1212).

G.22. ExxonMobil shall comply with the recordkeeping requirements for miscellaneous process vent provisions as required by 40 CFR 63 Subpart CC (including those for miscellaneous maintenance vents under 40 CFR 63.643(c)) (ARM 17.8.342 and 40 CFR 63 Subparts A and CC).

G.23. ExxonMobil shall maintain records documenting good air pollution control practices as required in Section III.G.6 and pursuant to the requirements outlined in 40 CFR 60.11(d) (ARM 17.8.749, Consent Decree Paragraph 70).

G.24. ExxonMobil shall conduct all applicable recordkeeping requirements in accordance with 40 CFR 60 Subparts A and J (ARM 17.8.340 and 40 CFR 60 Subparts A and J).

G.25. ExxonMobil shall comply with all applicable recordkeeping requirements of 40 CFR 60 Subparts A and Ja (ARM 17.8.340 and 40 CFR 60 Subparts A and Ja).

G.26. ExxonMobil shall conduct all applicable recordkeeping requirements in accordance with the FIP (Federal Implementation Plan for the Billings/Laurel Area).

G.27. ExxonMobil shall record the results of the Root Cause Failure Analysis according to Appendix H.

Reporting

G.28. Any required compliance source test report(s) shall be submitted in accordance with Section III.A.2 (ARM 17.8.106).

G.29. In accordance with Section 7 of the Stipulation (Appendix E of this permit), ExxonMobil shall submit quarterly reports within 30 days of the end of each calendar quarter. The quarterly reports shall be submitted to DEQ's Permitting and Compliance office in Helena and the Billings Regional Office. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written or hard copy data summary report (Board Order signed on June 12, 1998, and subsequent revisions of March 17, 2000; this requirement is "State Only").

G.30. ExxonMobil shall certify by a responsible official and submit quarterly reports to EPA within 30 days of the end of each calendar quarter. The quarterly reports shall contain information as required by the FIP. The quarterly report format shall consist of both a comprehensive electronic-magnetic report and a written or hard copy data summary report (Federal Implementation Plan for the Billings/Laurel Area FR Vol. 73, No. 77, April 21, 2008).

G.31. For flaring events in excess of 150 lbs SO_2/3-hr period caused by SSM, ExxonMobil shall comply with the notification and reporting requirements identified in affirmative defense provision in the FIP. (Federal Implementation Plan for the Billings/Laurel Area FR Vol. 73, No. 77, April 21, 2008.)

G.32. ExxonMobil shall comply with the reporting requirements for miscellaneous process vent provisions as required by 40 CFR 63 Subpart CC (including those for miscellaneous maintenance vents under 40 CFR 63.643(c)). (ARM 17.8.342 and 40 CFR 63, Subpart A and CC).

G.33. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1213)

G.34. The semiannual compliance monitoring reports shall provide a summary of any required monitoring, with all instances of deviations from permit requirements clearly identified. The report shall include the following (ARM 17.8.1212):

a. A summary of the results of any required reference method tests performed during the reporting period;

b. Reference to dates that quarterly reports were submitted;

c. Reference to dates that consent decree, SIP, and FIP required reports were submitted;

d. Summary of the records kept as required by Section III.G.23

e. Summary of compliance with the reporting requirements of 40 CFR 60 Subpart J during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 60 Subpart J;

f. Summary of compliance with the reporting requirements of 40 CFR 60 Subpart Ja during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 60 Subpart Ja;

g. Summary of compliance with the reporting requirements of 40 CFR 63 Subpart CC during the reporting period. This reporting requirement does not require the permittee to submit a report or compliance status determination earlier than is required in 40 CFR 63 Subpart CC.

H. EU15 – Oil Movements & Shipping (OM&S)

Group 1 Storage Vessels
Group 2 Storage Vessels
Wastewater Provision Vessels

Condition(s)	Pollutant/Parameters	Permit Limits	Compliance Demonstration Method Frequency		Reporting Requirements
H.1, H.6, H.11, H.16, H.17	Tanks #11 & #101 (and any installed or reconstructed after 1983)	40 CFR 60 Subpart Kb	40 CFR 60 Subpart Kb	40 CFR 60 Subpart Kb	Semiannually and 40 CFR 60 Subpart Kb
H.2, H.9, H.13, H.16, H.17	40 CFR 60 Subpart GGG	40 CFR 60 Subpart GGG	40 CFR 60 Subpart VV	40 CFR 60 Subpart VV	Semiannually and 40 CFR 60 Subpart GGG
H.3, H.7, H.12, H.16, H.17	Storage Vessels (Group 1 and 2)	40 CFR 63.646	40 CFR 63.119 - 63.121, 646, and 660	As required by 63.123 & 63.655	Semiannually and 40 CFR 63 Subpart CC
H.4, H.8, H.14, H.16, H.17	VOC fugitive emissions from Tank 26	515 tons/ 12-month rolling period	Engineering calculation/ equation	Monthly	
H.5, H.10, H.15, H.16, H.17	40 CFR 63 Subpart EEEE	40 CFR 63 Subpart EEEE	40 CFR 63 Subpart EEEE	40 CFR 63 Subpart EEEE	Semiannually and 40 CFR 63 Subpart EEEE

Conditions

H.1. ExxonMobil shall comply with all applicable requirements of 40 CFR 60 Subpart Kb - Volatile Organic Liquid Storage Vessels. These regulations shall apply to Tank #11 and Tank #101 and any other affected tank for which construction, reconstruction, or modification commenced after July 23, 1984 (ARM 17.8.340 and 40 CFR 60, Subpart Kb).

H.2. ExxonMobil shall comply with all applicable requirements of 40 CFR 60 Subpart GGG (ARM 17.8.340 and 40 CFR 60 Subpart GGG).

H.3. ExxonMobil shall comply with the Storage Vessels provisions of 40 CFR 63 Subpart CC (40 CFR 63.646 and 660), as appropriate (ARM 17.8.342 and 40 CFR 63 Subpart CC).

H.4. VOC emissions from Tank #26 shall not exceed 515 tons per rolling 12-month period. The VOC fugitive emissions shall be determined using the following equation (ARM 17.8.749):

$$W_{VOC} = 0.166677 \text{ lbs/ft}^3 * V_{inst} * [TVP \,/\, (12.9 \text{ psia} - TVP)]$$

Where:

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

H.5. ExxonMobil shall comply with all applicable requirements of 40 CFR 63 Subpart EEEE – Organic Liquids Distribution, including as applicable to the Toluene Rail Loading Rack and any other affected tank or piping for which construction, reconstruction, or modification commenced April 2, 2002 (ARM 17.8.342 and 40 CFR 63 Subpart EEEE).

Compliance Demonstration

H.6. ExxonMobil shall monitor compliance with 40 CFR 60, Subpart Kb by complying with §§60.113b through 60.114b (ARM 17.8.340 and 40 CFR 60 Subpart Kb).

H.7. ExxonMobil shall comply with the applicable Storage Vessels provisions of 40 CFR 63 Subpart CC (40 CFR 63.119 through 63.121, 63.646, and 63.660) (ARM 17.8.342 and 40 CFR 63 Subpart CC).

H.8. ExxonMobil shall document, by month, the total fugitive VOC emissions from Tank #26. By the 25th day of each month, ExxonMobil shall total the fugitive VOC emissions from Tank #26 for the previous month. The monthly information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749). ExxonMobil shall also calculate, by month, the rolling 12-month sum. By the 25th day of each month, ExxonMobil shall total and record the fugitive VOC emissions from Tank #26 for the previous 12 months (ARM 17.8.1213).

H.9. ExxonMobil shall test for equipment leaks in accordance with 40 CFR 60 Subpart GGG (ARM 17.8.340 and 40 CFR 60 Subpart GGG).

H.10. ExxonMobil shall comply with all applicable testing and continuous compliance requirements of 40 CFR 63 Subpart EEEE (ARM 17.8.342 and 40 CFR 63 Subpart EEEE).

Recordkeeping

H.11. ExxonMobil shall maintain on-site records for the monitoring of Tank #11 and Tank #101, and any other affected tank subject to 40 CFR 60, Subpart Kb, as required by 40 CFR 60.115b and 60.116b (ARM 17.8.340 and 40 CFR 63 Subpart Kb).

H.12. ExxonMobil shall comply with the recordkeeping requirements of storage vessel provisions of 40 CFR 63 Subpart CC (ARM 17.8.342 and 40 CFR 63 Subpart CC).

H.13. ExxonMobil shall comply with the recordkeeping requirements of 40 CFR 60 Subpart VV, as applicable and required by 40 CFR 60 Subpart GGG (ARM 17.8.340 and 40 CFR 60 Subpart GGG).

H.14. ExxonMobil shall maintain records of the VOC emissions required by Sections III.H.8, (ARM 17.8.1212).

H.15. ExxonMobil shall comply with all applicable recordkeeping requirements of 40 CFR 63 Subpart EEEE (ARM 17.8.342 and 40 CFR 63 Subpart EEEE).

Reporting

H.16. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1213)

H.17. The semiannual compliance monitoring reports shall provide a summary of any required monitoring, with all instances of deviations from permit requirements clearly identified. The report shall include the following (ARM 17.8.1212):

a. 12 month rolling sums of VOC emissions as required by Section III.H.14 for each month in the reporting period;

b. Summary of compliance with the reporting requirements of 40 CFR 60 Subpart Kb during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 60 Subpart Kb;

c. Summary of compliance with the reporting requirements of 40 CFR 60 Subpart GGG during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 60 Subpart GGG;

d. Summary of compliance with the reporting requirements of 40 CFR 63 Subpart CC during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 63 Subpart CC;

e. Summary of compliance with the reporting requirements of 40 CFR 63 Subpart EEEE during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 63 Subpart EEEE

I. EU17 – Refinery-Wide Fugitive Emissions

Subpart GGG and GGGa Compressors, and facility-wide fugitive emissions, including, but not limited to, pumps, valves, flanges, and other equipment in HAP service, or in VOC service since January 1983, within the following emitting units:

EU00 – RFG Devices (RFG supply lines)
EU01 – Crude Unit
EU02 – Hydrofining Units #2 & #3
EU03 – Fluid Coker Unit
EU04 – Powerforming Unit
EU05 – Alky/Splitter/Rerun/Diene Unit
EU06 – Merox Unit
EU07 – Hydrofining Unit #1
EU08 – Deethanizer Unit
EU09 – FCCU
EU10 – Unsaturated Light Ends Unit
EU11 – Hydrocracking Unit
EU12 – H_2 Plant
EU14 – Oil Movement & Activities
EU15 – Oil Movement & Shipping
EU16 – CHUB Unit, including the C1201A and C1201B compressors in Hydrogen service

Condition(s)	Pollutant/Parameters	Permit Limits	Compliance Demonstration		Reporting Requirements
			Method	Frequency	
I.1, I.5, I.8, I.11, I.12, I.13	VOC, HAP, and Benzene Equipment Leaks	40 CFR 63 Subpart CC	40 CFR 60 Subpart VV	40 CFR 60 Subpart VV	Semiannually and 40 CFR 63 Subpart CC
I.2, I.5, I.11, I.12, I.13	HAP from Heat Exchange System	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	40 CFR 63 Subpart CC	Semiannually and 40 CFR 63 Subpart CC
I.3, I.6, I.9, I.12, I.13	Equipment Leaks	40 CFR 60 Subpart GGG	40 CFR 60 Subpart VV	40 CFR 60 Subpart VV	Semiannually and 40 CFR 60 Subpart GGG
I.4, I.7, I.10, I.12, I.13	Equipment Leaks	40 CFR 60 Subpart GGGa	40 CFR 60 Subpart VVa	40 CFR 60 Subpart VVa	Semiannually and 40 CFR 60 Subpart GGGa

Conditions

I.1. ExxonMobil shall comply with applicable requirements of 40 CFR 63 Subpart CC, including as applicable for an existing facility that is subject to leak standards for equipment in HAP service applicable under 40 CFR 63.648(a) (and 40 CFR 60 Subpart VV, as applicable) (ARM 17.8.342 and 40 CFR 63 Subpart CC).

I.2. ExxonMobil shall comply with applicable requirements of 40 CFR 63 Subpart CC, including for an existing facility that is subject to the heat exchange system provisions as described in 40 CFR 63.654, as applicable (ARM 17.8.342 and 40 CFR 63 Subpart CC).

I.3. ExxonMobil shall comply with all applicable requirements of 40 CFR 60 Subpart GGG (ARM 17.8.340 and 40 CFR 60 Subpart GGG). The C-1201A and C-1201B compressors are subject to 40 CFR 60 Subpart GGG as compressors in hydrogen service.

I.4. ExxonMobil shall comply with all applicable requirements of 40 CFR 60 Subpart GGGa (ARM 17.8.340 and 40 CFR 60 Subpart GGGa). The Wet Gas Compressor C-310 is subject to leak standards for equipment in VOC service under 40 CFR 60 Subpart GGGa.

Compliance Demonstration

I.5. ExxonMobil shall comply with applicable monitoring and inspection, test methods and procedures, and repair provisions required under 40 CFR 63 Subpart CC (40 CFR 63.644, 63.645, 63.648, and 63.654) (ARM 17.8.342 and 40 CFR 63 Subpart CC).

I.6. ExxonMobil shall comply with applicable monitoring requirements of 40 CFR 60 Subpart GGG including referenced monitoring requirements of 40 CFR 60 Subpart VV (ARM 17.8.340 and 40 CFR 60 Subpart GGG).

I.7. ExxonMobil shall comply with applicable monitoring requirements of 40 CFR 60 Subpart GGGa including referenced monitoring requirements of 40 CFR 60 Subpart VVa (ARM 17.8.340 and 40 CFR 60 Subpart GGGa).

Recordkeeping

I.8. ExxonMobil shall comply with the recordkeeping requirements for equipment leak standards in accordance with 40 CFR 63 Subpart CC including 40 CFR 63.655 (ARM 17.8.342 and 40 CFR 63 Subpart CC).

I.9. ExxonMobil shall comply with applicable recordkeeping requirements of 40 CFR 60 Subpart GGG (including applicable recordkeeping requirements of 40 CFR 60 Subpart VV as referenced) (ARM 17.8.340 and 40 CFR 60 Subpart GGG).

I.10. ExxonMobil shall comply with applicable recordkeeping requirements of 40 CFR 60 Subpart GGGa (including applicable recordkeeping requirements of 40 CFR 60 Subpart VVa as referenced) (ARM 17.8.340 and 40 CFR 60 Subpart GGGa).

Reporting

I.11. ExxonMobil shall comply with all applicable reporting requirements set forth in 40 CFR 63 Subpart CC (ARM 17.8.342 and 40 CFR 63 Subpart CC).

I.12. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1213)

I.13. The semiannual compliance monitoring reports shall provide a summary of any required monitoring, with all instances of deviations from permit requirements clearly identified. The report shall include the following (ARM 17.8.1212):

a. A summary of the results of any required reference method tests performed during the reporting period; and

b. Summary of compliance with the reporting requirements of 40 CFR 63 Subpart CC during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 63 Subpart CC.

c. Summary of compliance with the reporting requirements of 40 CFR 60 Subpart GGG during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 60 Subpart GGG.

d. Summary of compliance with the reporting requirements of 40 CFR 60 Subpart GGGa during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 60 Subpart GGGa.

J. EU18 – Emergency/Back Up Portable and Stationary Engines

EU18a: SE1-SE15, IEU06a & IEU06b

Condition(s)	Pollutant/Parameters	Permit Limits	Compliance Demonstration Method	Compliance Demonstration Frequency	Reporting Requirements
J.1, J.10, J.18, J.23, J.24	Operating Limits	Hours of Operation (see Table 1)	Recordkeeping	Monthly	Semiannually
J.1, J.11, J.18, J.23, J.24	Engine Size	Maximum Rated horsepower (hp) (see Table 1)	Recordkeeping	Monthly	Semiannually
J.1, J.11, J.18, J.23, J.24	Engine Emissions Rating	Tier Rating (see Table 1)	Recordkeeping	Ongoing	Semiannually
J.2, J.12, J.18, J.23, J.24	Engine SE6	EPA certification of Tier 2 or higher	Recordkeeping	Ongoing	Semiannually
J.3, J.13, J.18, J.23, J.24	any new or replacement engine	notify DEQ within 30 days after the commencement of operation	Reporting	As Required	Semiannually and as required
J.4, J.14, J.18, J.23, J.24	Engine Certification	EPA Tier 3 or higher	Recordkeeping	Monthly	Semiannually
J.5, J.15, J.19, J.21, J.23, J.24	40 CFR 63 Subpart ZZZZ	40 CFR 63 Subpart ZZZZ	40 CFR 63 Subpart ZZZZ	40 CFR 63 Subpart ZZZZ	Semiannually and 40 CFR 63 Subpart ZZZZ
J.6, J.16, J.20, J.22, J.23, J.24	40 CFR 60 Subpart IIII	40 CFR 60 Subpart IIII	40 CFR 60 Subpart IIII	40 CFR 60 Subpart IIII	Semiannually and 40 CFR 60 Subpart IIII
J.7, J.17, J.18, J.23, J.24	SO_2- Fuel Sulfur Limits in Diesel Fuel	Low-sulfur diesel fuel (0.05% wt)	Recordkeeping	Monthly	Semiannually
J.8, J.17, J.18, J.23, J.24	SO_2- Fuel Sulfur Limits in Diesel Fuel	Ultra low-sulfur diesel fuel (0.0015% wt)	Recordkeeping	Monthly	Semiannually
J.9, J.17, J.18, J.23, J.24	SO_2 – Fuel Sulfur Limits in Gasoline	Gasoline sulfur content (0.1%w)	Recordkeeping	Monthly	Semiannually

Conditions

J.1. The emergency/back up engines are limited to the hours of operation on a rolling 12-month period, maximum horsepower rating, and minimum Tier Rating listed below (Table 1):

TABLE 1

ID No.	Emitting Unit ID	Description	Limited Hours	Rule Reference
SE1	HC/M601	Hydrocracker Backup Power Generator - Diesel	1,800 hr/yr	ARM 17.8.752

TABLE 1				
ID No.	**Emitting Unit ID**	**Description**	**Limited Hours**	**Rule Reference**
SE2	UT/P917B	Cooling Water Return to Alkylation Unit Water Screen (Fire Water) – Diesel	1,000 hr/yr	ARM 17.8.752
SE3	UT/P917A	Cooling Water Return to Alkylation Unit Water Screen (Fire Water) – Diesel	1,000 hr/yr	ARM 17.8.752
SE4	UT/P916	Pond 6 Water to Fire Mains - Diesel	1,000 hr/yr	ARM 17.8.752
SE5	CR/M201	Crude/Coker Backup Power Generator - Diesel	2,000 hr/yr	ARM 17.8.752
SE6	UT/C4	Boiler House Air Compressor –Diesel, minimum EPA Tier 2 rating, not to exceed 475-hp	2,000 hr/yr	ARM 17.8.749
SE7	UT/Port1	Boiler House Backup Air Compressor, Portable, Diesel-fired, minimum Tier 3 rating, not to exceed 600-hp	1,500 hr/yr	ARM 17.8.749
SE8	UT/Port2	Boiler House Backup Air Compressor, Portable, Diesel-fired, minimum Tier 3 rating, not to exceed 600-hp	1,500 hr/yr	ARM 17.8.749
SE9	EMES/Eng01	Site Remediation or Miscellaneous Use, Diesel-fired, minimum Tier 3 rating, not to exceed 250-hp	No limit on hours	ARM 17.8.749
SE10	EMES/Eng02	Site Remediation or Miscellaneous Use, Diesel-fired, minimum Tier 3 rating, not to exceed 250-hp	No limit on hours	ARM 17.8.749
SE11	EMES/Eng03	Site Remediation or Miscellaneous Use, Diesel-fired, minimum Tier 3 rating, not to exceed 250-hp	No limit on hours	ARM 17.8.749
SE12*	EMES/Eng04	Miscellaneous use, Diesel-fired, minimum Tier 3 rating, not to exceed 500-hp each	2,100,000 hp-hrs**	ARM 17.8.749
SE13	EMES/Eng05	Emergency and Site Remediation, Diesel-fired, minimum Tier 3 rating, not to exceed 100-hp	No limit on hours	ARM 17.8.749
SE14	UT/Port3	SLEB Backup Portable Engine, Diesel fired, not to exceed 600 hp, minimum EPA Tier III rating	3,000 hr/yr	ARM 17.8.749
SE15	MOB/Lab	MOB/Lab Emergency Backup Engine, Diesel Fired, not to exceed 324 hp, minimum EPA Tier III rating, based on 500 hours maximum	No specified limit	ARM 17.8.745
SE16 (formerly IEU06a)	UT/P1A	Fire Water Pump at River Water Pump House -Gasoline	2,000 hr/yr	ARM 17.8.752
SE17 (formerly IEU06b)	UT/P1B	Fire Water Pump at River Water Pump House -Gasoline	2,000 hr/yr	ARM 17.8.752
LK01-04	Lab Knock Engines	Four (4) Lab Knock Engines	No limit on hours	

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

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

J.2. Engine SE6 shall have an EPA certification of Tier 2 or higher (ARM 17.8.749)

J.3. ExxonMobil shall notify DEQ within 30 days after the commencement of operation of any new or replacement engine (ARM 17.8.749).

J.4. Engines SE7 through SE14 shall have an EPA certification of Tier 3 or higher (ARM 17.8.749).

J.5. ExxonMobil shall comply with all applicable requirements of 40 CFR 63 Subpart ZZZZ, NESHAP for Stationary Reciprocating Internal Combustion Engines (ARM 17.8.342 and 40 CFR 63 Subpart ZZZZ).

J.6. ExxonMobil shall comply with all applicable requirements of 40 CFR 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (ARM 17.8.340 and 40 CFR 60 Subpart IIII – expected to be applicable to engines SE7-SE15).

J.7. ExxonMobil shall use only low-sulfur diesel fuel with a sulfur content less than or equal to 0.05% in the diesel-fired engines SE1 through SE6 (ARM 17.8.752).

J.8. ExxonMobil shall use only ultra-low sulfur diesel fuel with a sulfur content less than or equal to 0.0015% in the diesel-fired engines SE7 through SE14 (ARM 17.8.752).

J.9. ExxonMobil shall use gasoline with a sulfur content less than or equal to 0.1% in the gasoline-fired engines IEU06a and IEU06b (ARM 17.8.752).

Compliance Demonstration

J.10. ExxonMobil shall document by the 25th day of each month the number of operational hours since the previous month's documentation event for each of the emergency/backup engines. The monthly information shall be used to monitor compliance with the rolling 12-month limitations in Section III.J.1. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

J.11. ExxonMobil shall document the hp ratings of engines SE7 through SE14. Manufacturer specification sheets that indicate the maximum rated power will satisfy this requirement. The information shall be submitted along with the annual emission inventory (ARM 17.8.749).

J.12. ExxonMobil shall maintain manufacturer/vendor specification sheets indicating the Tier emissions level rating of the engine (ARM 17.8.1212).

J.13. ExxonMobil shall demonstrate compliance with the notification requirements of Section III.J.3 by maintaining records of the reports made to DEQ for a minimum of 5 years from the date of the report (ARM 17.8.1212).

J.14. ExxonMobil shall maintain documentation of certification with EPA Tier 3 or better emission standards for engine units SE7 through SE14. This documentation shall be used to demonstrate compliance with Section III.J.4 above. The information shall be submitted along with the annual emission inventory (ARM 17.8.749).

J.15. ExxonMobil shall demonstrate compliance with 40 CFR 63 Subpart ZZZZ through applicable testing and initial compliance requirements, continuous compliance requirements, notifications, reports, and records, and other requirements and information as defined and required by 40 CFR 63 Subpart ZZZZ (ARM 17.8.342 and 40 CFR 60 Subpart ZZZZ).

J.16. ExxonMobil shall demonstrate compliance with 40 CFR 60 Subpart IIII through applicable compliance requirements, testing requirements for owners and operators, notification, reports, and records for owners and operators, and any special requirements and general provisions as applicable and required by 40 CFR 60 Subpart IIII (ARM 17.8.340 and 40 CFR 60 Subpart IIII).

J.17. ExxonMobil shall document, annually, the maximum sulfur content of the diesel and gasoline fuel used by the engines for the previous calendar year. Vendor specifications or certification that the fuels met the maximum sulfur content allowed by the current motor fuel regulations (40 CFR Part 80) will satisfy this requirement. The annual information shall be used to monitor compliance with the limitations in Sections III.J.7 through J.9. The information shall be submitted along with the annual emission inventory (ARM 17.8.749 and ARM 17.8.752).

Recordkeeping

J.18. ExxonMobil shall maintain on site, for a minimum of 5 years from the date of record creation, records as described in Sections III.J.10 through J.14 and Section III.J.17 (ARM 17.8.1212).

J.19. ExxonMobil shall comply with all applicable reporting requirements set forth in 40 CFR 63 Subpart ZZZZ (ARM 17.8.342 and 40 CFR 63 Subpart ZZZZ).

J.20. ExxonMobil shall comply with all applicable reporting requirements set forth in 40 CFR 60 Subpart IIII (ARM 17.8.340 and 40 CFR 60 Subpart IIII).

Reporting

J.21. ExxonMobil shall comply with all applicable reporting requirements set forth in 40 CFR 63 Subpart ZZZZ (ARM 17.8.342 and 40 CFR 60 Subpart ZZZZ).

J.22. ExxonMobil shall comply with all applicable reporting requirements set forth in 40 CFR 60 Subpart IIII (ARM 17.8.340 and 40 CFR 60 Subpart IIII).

J.23. The annual compliance certification report required by Section V.B must contain a certification statement for the above applicable requirements (ARM 17.8.1213)

J.24. The semiannual compliance monitoring reports shall provide a summary of any required monitoring, with all instances of deviations from permit requirements clearly identified. The report shall include the following (ARM 17.8.1212):

a. A summary of the results of any required reference method tests performed during the reporting period;

b. A summary of records kept as required by Section III.J.18;

c. Summary of compliance with the reporting requirements of 40 CFR 60 Subpart IIII during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 60 Subpart IIII;

d. Summary of compliance with the reporting requirements of 40 CFR 63 Subpart ZZZZ during the reporting period. This reporting requirement does not require the permittee to submit any report or compliance status determination earlier than is required by 40 CFR 63 Subpart ZZZZ.

SECTION IV. NON-APPLICABLE REQUIREMENTS

Air Quality Administrative Rules of Montana (ARM) and Federal Regulations, identified as not applicable to the facility or to a specific emission unit at the time of the permit issuance, are listed below (ARM 17.8.1214). The following list does not preclude the need to comply with any new requirements that may become applicable during the permit term.

A. Facility-Wide

The following table contains non-applicable requirements, which are administrated by the Air Quality Bureau of the Department of Environmental Quality.

Rule Citations	Reasons
ARM 17.8.309(4), ARM 17.8.320, ARM 17.8.321, ARM 17.8.322(2), ARM 17.8.322(3), ARM 17.8.326, ARM 17.8.330 - ARM 17.8.335, ARM 17.8.610, ARM 17.8.613, and ARM 17.8.614.	These rules are not applicable because the facility does not operate sources affected by the cited rules.
40 CFR 60, Subparts B, C, Ca - Ce 40 CFR 60, Subparts D, Da, Db 40 CFR 60, Subparts E-I 40 CFR 60, Subparts K and Ka 40 CFR 60, Subparts L-Z 40 CFR 60, Subparts AA-EE 40 CFR 60, Subparts GG-HH 40 CFR 60, Subparts KK-NN 40 CFR 60, Subparts PP-TT 40 CFR 60, Subparts WW 40 CFR 60, Subparts AAA- BBB 40 CFR 60, Subpart DDD 40 CFR 60, Subparts FFF 40 CFR 60, Subparts HHH-LLL 40 CFR 60, Subparts NNN-PPP 40 CFR 60, Subparts RRR- WWW 40 CFR 60, Subparts AAAA- HHHH 40 CFR 60, Subparts JJJJ- OOOO	These requirements are not applicable because the facility is not an affected source as defined in these regulations.
40 CFR 61, Subparts B-I 40 CFR 61, Subparts K-L 40 CFR 61, Subparts N-U 40 CFR 61, Subparts W -EE	ExxonMobil-Billings Refinery does not contain any sources regulated by these rules.
40 CFR 63, Subparts B – D 40 CFR 63 Subpart J 40 CFR 63, Subparts S-BB 40 CFR 63, Subparts DD-TTT 40 CFR 63, Subpart VVV – DDDD 40 CFR 63, Subpart FFFF – CCCCC 40 CFR 63, Subpart EEEEE – FFFFF	These requirements are not applicable because the facility is not an affected source as defined in these regulations.

Rule Citations	Reasons
40 CFR 63, Subpart HHHHH – KKKKK 40 CFR 63, Subpart MMMMM – ZZZZZ 40 CFR 63, Subpart DDDDDD - ZZZZZZ 40 CFR 63, Subpart BBBBBBB-HHHHHHH	

B. Emission Units

The following table contains non-applicable requirements, which are relevant to specific emitting units:

Emission Unit ID	Rule Citation	Reason
EU03 – Coker/KCOB	Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, & May 22, 2003, Exhibit A: §4(D)(2) and §(6)(B)(4)(b)	ExxonMobil installed an SO_2 CEMS on the KCOB stack. Provisions for a CEMS-Equivalent Monitoring Plan are no longer applicable.
EU03 – Coker/KCOB – Misc Process Vents	Monitoring provisions for miscellaneous process vents (40 CFR 63.644)	The Coker Process Gas Group 1 Misc. Process vent is vented to a boiler or process heater with a design input capacity greater than 44 megawatt (>150 MMBtu/hr). The process is vented to YELP or the KCOB.
EU00 - Process Heaters Other: F-1 and F-401	40 CFR 60 Subparts Db and Dc	"Process Heaters" as defined by 40 CFR 60.41, are not "steam generating units" and are therefore not subject to Subparts Db or Dc.
Refinery-wide Benzene-containing Wastewater	40 CFR 61.342(c) & (d) (40 CFR 61.342(e))	ExxonMobil has opted for, and is required to meet, the "6BQ" alternative for managing and treating waste.

C. Cause Orders

The permit application requested that the following Judgments be identified as non-applicable, as there are no continuous or future requirements associated with them.

Judgment	Description	Reason
Order and Final Judgment Cause No. DV 90-0068	FCC/CO Unit Operational Compliance Strategy	Per Section 12B of the order #DV90-0068, this requirement expired 2 years after the effective date as defined in section 12B. There are no continuous or future requirements.
Consent Decree, Judgment and Order Cause No. DV91-719	Coker CO Boiler Stack Opacity Monitoring	There are no on-going requirements.

D. Streamlined Requirements

Pursuant to ARM 17.8.1212, as of the date this permit is issued, 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, Consent Decree paragraph 60: ExxonMobil 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.
	Refinery-wide block hourly fuel sulfur limit of 0.96 lb/MMBtu fired (13,234 mg H_2S/dscm fuel at a minimum RFG HHV of 810 Btu/scf)		

Emission Unit ID	Subsumed Rule Citation	Streamlined Rule Citation	Reason
Fuel Gas Combustion Devices – • EU00 • EU03a (KCOB) • EU09a (CCOB)	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 – Billings/Laurel SO_2 Control Plan (Exhibit A), Section 6(B)(8).	The RFG H_2S CEMS required by NSPS Subpart J meets or exceeds the performance specifications for the 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 Subpart J and Subpart 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.

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(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))	40 CFR 60 Subpart J: 230 mg H_2S/dscm fuel (equivalent to 0.10 grains/dscf or ~160 ppm_{vd} H_2S @ STP)	The NSPS Subpart J fuel sulfur (as H_2S) limit is much more stringent. Compliance 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.
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	ExxonMobil shall operate and maintain a CEMS to measure SO_2 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 Sections 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 SO_2 CEM which meets the requirements of 40 CFR 60 Appendix F, within eight hours of when the Coker unit flue gases begin	The FIP limit is equal to or more stringent than the SIP limit.

Emission Unit ID	Subsumed Rule Citation	Streamlined Rule Citation	Reason
	Section 6 as long as Coker process gas continues to be exhausted through the KCOB stack. (Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003)	exhausting through the Coker CO Boiler stack (Federal Implementation Plan for the 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	Consent decree requirements have stricter flare provisions than the Board Order, from flare minimization to investigation.

Emission Unit ID	Subsumed Rule Citation	Streamlined Rule Citation	Reason
		event, in accord with the Root Cause Failure	
EU14 – Oil Movements & Utilities (OM&U), specifically, EU14a: Flare – Flare or Turnaround Flare	For flaring events in excess of 150 lbs/3-hr period, ExxonMobil shall 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").	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 Analysis as prescribed in Appendix H (Consent Decree paragraphs 79, 80, 81). And Section V.E – Prompt Deviation requirements, including malfunction reporting requirements	The Consent Decree provisions focus on investigating and minimizing flaring overall. In addition, under the Consent Decree, 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. GENERAL PERMIT CONDITIONS

A. Compliance Requirements

ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(a)-(c)&(e), §1206(6)(c)&(b)

1. The permittee must comply with all conditions of the permit. Any noncompliance with the terms or conditions of the permit constitutes a violation of the Montana Clean Air Act, and may result in enforcement action, permit modification, revocation and reissuance, or termination, or denial of a permit renewal application under ARM Title 17, Chapter 8, Subchapter 12.

2. The filing of a request by the permittee for a permit modification, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition.

3. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of the permit. If appropriate, this factor may be considered as a mitigating factor in assessing a penalty for noncompliance with an applicable requirement if the source demonstrates that both the health, safety or environmental impacts of halting or reducing operations would be more serious than the impacts of continuing operations, and that such health, safety, or environmental impacts were unforeseeable and could not have otherwise been avoided.

4. The permittee shall furnish to DEQ, within a reasonable time set by DEQ (not to be less than 15 days), any information that DEQ may request in writing to determine whether cause exists for modifying, revoking and reissuing, or terminating the permit, or to determine compliance with the permit. Upon request, the permittee shall also furnish to DEQ copies of those records that are required to be kept pursuant to the terms of the permit. This subsection does not impair or otherwise limit the right of the permittee to assert the confidentiality of the information requested by DEQ, as provided in 75-2-105, MCA.

5. Any schedule of compliance for applicable requirements with which the source is not in compliance with at the time of permit issuance shall be supplemental to, and shall not sanction noncompliance with, the applicable requirements on which it was based.

6. For applicable requirements that will become effective during the permit term, the source shall meet such requirements on a timely basis unless a more detailed plan or schedule is required by the applicable requirement or DEQ.

B. Certification Requirements

ARM 17.8, Subchapter 12, Operating Permit Program §1207 and §1213(7)(a)&(c)-(d)

1. Any application form, report, or compliance certification submitted pursuant to ARM Title 17, Chapter 8, Subchapter 12, shall contain certification by a responsible official of truth, accuracy, and completeness. This certification and any other certification required under ARM Title 17, Chapter 8, Subchapter 12, shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate and complete.

2. Compliance certifications shall be submitted by October 15 of each year, or more frequently if otherwise specified in an applicable requirement or elsewhere in the permit. Each certification must include the required information for the previous year (i.e., September 1 – August 31).

3. Compliance certifications shall include the following:

    a. The identification of each term or condition of the permit that is the basis of the certification;

    b. The identification of the method(s) or other means used by the owner or operator for determining the status of compliance with each term and condition during the certification period, consistent with ARM 17.8.1212;

    c. The status of compliance with each term and condition for the period covered by the certification, *including whether compliance during the period was continuous or intermittent* (based on the method or means identified in ARM 17.8.1213(7)(c)(ii), as described above); and

    d. Such other facts as DEQ may require to determine the compliance status of the source.

4. All compliance certifications must be submitted to the Environmental Protection Agency, as well as to DEQ, at the addresses listed in the Notification Addresses Appendix C of this permit.

C. Permit Shield
ARM 17.8, Subchapter 12, Operating Permit Program §1214(1)-(4)

1. The applicable requirements and non-federally enforceable requirements are included and specifically identified in this permit and the permit includes a precise summary of the requirements not applicable to the source. Compliance with the conditions of the permit shall be deemed compliance with any applicable requirements and any non-federally enforceable requirements as of the date of permit issuance.

2. The permit shield described in 1 above shall remain in effect during the appeal of any permit action (renewal, revision, reopening, or revocation and reissuance) to the Board of Environmental Review (Board), until such time as the Board renders its final decision.

3. Nothing in this permit alters or affects the following:

    a. The provisions of Section 7603 of the FCAA, including the authority of the administrator under that section;

    b. The liability of an owner or operator of a source for any violation of applicable requirements prior to or at the time of permit issuance;

    c. The applicable requirements of the Acid Rain Program, consistent with Section 7651g(a) of the FCAA;

    d. The ability of the administrator to obtain information from a source pursuant to Section 7414 of the FCAA;

e. The ability of DEQ to obtain information from a source pursuant to the Montana Clean Air Act, Title 75, Chapter 2, MCA;

f. The emergency powers of DEQ under the Montana Clean Air Act, Title 75, Chapter 2, MCA; and

g. The ability of DEQ to establish or revise requirements for the use of Reasonably Available Control Technology (RACT) as defined in ARM Title 17, Chapter 8. However, if the inclusion of a RACT into the permit pursuant to ARM Title 17, Chapter 8, Subchapter 12, is appealed to the Board, the permit shield, as it applies to the source's existing permit, shall remain in effect until such time as the Board has rendered its final decision.

4. Nothing in this permit alters or affects the ability of DEQ to take enforcement action for a violation of an applicable requirement or permit term demonstrated pursuant to ARM 17.8.106, Source Testing Protocol.

5. Pursuant to ARM 17.8.132, for the purpose of submitting a compliance certification, nothing in these rules shall preclude the use, including the exclusive use, of any credible evidence or information relevant to whether a source would have been in compliance. However, when compliance or noncompliance is demonstrated by a test or procedure provided by permit or other applicable requirements, the source shall then be presumed to be in compliance or noncompliance unless that presumption is overcome by other relevant credible evidence.

6. The permit shield will not extend to minor permit modifications or changes not requiring a permit revision (see Sections I & J).

7. The permit shield will extend to significant permit modifications and transfer or assignment of ownership (see Sections K & O).

D. Monitoring, Recordkeeping, and Reporting Requirements
ARM 17.8, Subchapter 12, Operating Permit Program §1212(2)&(3)

1. Unless otherwise provided in this permit, the permittee shall maintain compliance monitoring records that include the following information:

   a. The date, place as defined in the permit, and time of sampling or measurement;

   b. The date(s) analyses were performed;

   c. The company or entity that performed the analyses;

   d. The analytical techniques or methods used;

   e. The results of such analyses; and

   f. The operating conditions at the time of sampling or measurement.

2. The permittee shall retain records of all required monitoring data and support information for a period of at least five years from the date of the monitoring sample, measurement,

report, or application. Support information includes all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation, and copies of all reports required by the permit. All monitoring data, support information, and required reports and summaries may be maintained in computerized form at the plant site if the information is made available to Department personnel upon request, which may be for either hard copies or computerized format. Strip-charts must be maintained in their original form at the plant site and shall be made available to Department personnel upon request.

3. The permittee shall submit to DEQ, at the addresses located in the Notification Addresses Appendix C of this permit, reports of any required monitoring by April 15 and October 15 of each year, or more frequently if otherwise specified in an applicable requirement or elsewhere in the permit. The monitoring report submitted on October 15 of each year must include the required monitoring information for the period of March 1 through August 31 of the previous year. The monitoring report submitted on April 15 of each year must include the required monitoring information for the period of September 1 through February 29 of the current year. All instances of deviations from the permit requirements must be clearly identified in such reports. All required reports must be certified by a responsible official, consistent with ARM 17.8.1207.

E. Prompt Deviation Reporting
ARM 17.8, Subchapter 12, Operating Permit Program §1212(3)(b)

The permittee shall promptly report deviations from permit requirements, including those attributable to upset conditions as defined in the permit, the probable cause of such deviations, and any corrective actions or preventive measures taken. To be considered prompt, deviations shall be reported to DEQ within the following timeframes (unless otherwise specified in an applicable requirement):

1. For deviations which may result in emissions potentially in violation of permit limitations:

    a. An initial phone notification (or faxed or electronic notification) describing the incident within 24 hours (or the next business day) of discovery; and,

    b. A follow-up written, faxed, or electronic report within 30 days of discovery of the deviation that describes the probable cause of the reported deviation and any corrective actions or preventative measures taken.

2. For deviations attributable to malfunctions, deviations shall be reported to DEQ in accordance with the malfunction reporting requirements under ARM 17.8.110; and

3. For all other deviations, deviations shall be reported to DEQ via a written, faxed, or electronic report within 90 days of discovery (as determined through routine internal review by the permittee).

4. For flare events caused by malfunctions, ExxonMobil shall also follow FIP reporting requirements.

Prompt deviation reports do not need to be resubmitted with regular semiannual (or other routine) reports but may be referenced by the date of submittal.

F. Emergency Provisions
ARM 17.8, Subchapter 12, Operating Permit Program §1201(13) and §1214(5), (6)&(8)

1. An "emergency" means any situation arising from sudden and reasonably unforeseeable events beyond the control of the source, including acts of God, which situation requires immediate corrective action to restore normal operation and causes the source to exceed a technology-based emission limitation under this permit due to the unavoidable increases in emissions attributable to the emergency. An emergency shall not include noncompliance to the extent caused by improperly designed equipment, lack of reasonable preventive maintenance, careless or improper operation, or operator error.

2. An emergency constitutes an affirmative defense to an action brought for noncompliance with a technology-based emission limitation if the permittee demonstrates through properly signed, contemporaneous logs, or other relevant evidence, that:

    a. An emergency occurred, and the permittee can identify the cause(s) of the emergency;

    b. The permitted facility was at the time being properly operated;

    c. During the period of the emergency the permittee took all reasonable steps to minimize levels of emissions that exceeded the emission standards or other requirements in the permit; and

    d. The permittee submitted notice of the emergency to DEQ within 2 working days of the time when emission limitations were exceeded due to the emergency. This notice fulfills the requirements of ARM 17.8.1212(3)(b). This notice must contain a description of the emergency, any steps taken to mitigate emissions, and corrective actions taken.

3. These emergency provisions are in addition to any emergency, malfunction or upset provision contained in any applicable requirement.

G. Inspection and Entry
ARM 17.8, Subchapter 12, Operating Permit Program §1213(3)&(4)

1. Upon presentation of credentials and other requirements as may be required by law, the permittee shall allow DEQ, the administrator, or an authorized representative (including an authorized contractor acting as a representative of DEQ or the administrator) to perform the following:

    a. Enter the premises where a source required to obtain a permit is located or emissions-related activity is conducted, or where records must be kept under the conditions of the permit;

    b. Have access to and copy, at reasonable times, any records that must be kept under the conditions of the permit;

    c. Inspect at reasonable times any facilities, emission units, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under the permit; and

d. As authorized by the Montana Clean Air Act and rules promulgated thereunder, sample or monitor, at reasonable times, any substances or parameters at any location for the purpose of assuring compliance with the permit or applicable requirements.

2. The permittee shall inform the inspector of all workplace safety rules or requirements at the time of inspection. This section shall not limit in any manner DEQ's statutory right of entry and inspection as provided for in 75-2-403, MCA.

H. Fee Payment
ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(f) and ARM 17.8, Subchapter 5, Air Quality Permit Application, Operation, and Open Burning Fees §505(3)-(5) (STATE ONLY)

1. The permittee must pay application and operating fees, pursuant to ARM Title 17, Chapter 8, Subchapter 5.

2. Annually, DEQ shall provide the permittee with written notice of the amount of the fee and the basis for the fee assessment. The air quality operation fee is due 30 days after receipt of the notice unless the fee assessment is appealed pursuant to ARM 17.8.511. If any portion of the fee is not appealed, that portion of the fee that is not appealed is due 30 days after receipt of the notice. Any remaining fee, which may be due after the completion of an appeal, is due immediately upon issuance of the Board's decision or upon completion of any judicial review of the Board's decision.

3. If the permittee fails to pay the required fee (or any required portion of an appealed fee) within 90 days of the due date of the fee, DEQ may impose an additional assessment of 15% of the fee (or any required portion of an appealed fee) or $100, whichever is greater, plus interest on the fee (or any required portion of an appealed fee), computed at the interest rate established under 15-31-510(3), MCA.

I. Minor Permit Modifications
ARM 17.8, Subchapter 12, Operating Permit Program §1226(3)&(11)

1. An application for a minor permit modification need only address in detail those portions of the permit application that require revision, updating, supplementation, or deletion, and may reference any required information that has been previously submitted.

2. The permit shield under ARM 17.8.1214 will not extend to any minor modifications processed pursuant to ARM 17.8.1226.

J. Changes not Requiring Permit Revision
ARM 17.8, Subchapter 12, Operating Permit Program §1224(1)-(3), (5)&(6)

1. The permittee is authorized to make changes within the facility as described below, provided the following conditions are met:

   a. The proposed changes do not require the permittee to obtain a Montana Air Quality Permit under ARM Title 17, Chapter 8, Subchapter 7;

b. The proposed changes are not modifications under Title I of the FCAA, or as defined in ARM Title 17, Chapter 8, Subchapters 8, 9, or 10;

c. The emissions resulting from the proposed changes do not exceed the emissions allowable under this permit, whether expressed as a rate of emissions or in total emissions;

d. The proposed changes do not alter permit terms that are necessary to enforce applicable emission limitations on emission units covered by the permit; and

e. The facility provides the administrator and DEQ with written notification at least 7 days prior to making the proposed changes.

2. The permittee and DEQ shall attach each notice provided pursuant to 1.e above to their respective copies of this permit.

3. Pursuant to the conditions above, the permittee is authorized to make Section 502(b)(10) changes, as defined in ARM 17.8.1201(30), without a permit revision. For each such change, the written notification required under 1.e above shall include a description of the change within the source, the date on which the change will occur, any change in emissions, and any permit term or condition that is no longer applicable because of the change.

4. The permittee may make a change not specifically addressed or prohibited by the permit terms and conditions without requiring a permit revision, provided the following conditions are met:

   a. Each proposed change does not weaken the enforceability of any existing permit conditions;

   b. DEQ has not objected to such change;

   c. Each proposed change meets all applicable requirements and does not violate any existing permit term or condition; and

   d. The permittee provides contemporaneous written notice to DEQ and the administrator of each change that is above the level for insignificant emission units as defined in ARM 17.8.1201(22) and 17.8.1206(3), and the written notice describes each such change, including the date of the change, any change in emissions, pollutants emitted, and any applicable requirement that would apply because of the change.

5. The permit shield authorized by ARM 17.8.1214 shall not apply to changes made pursuant to ARM 17.8.1224(3) and (5) but is applicable to terms and conditions that allow for increases and decreases in emissions pursuant to ARM 17.8.1224(4).

K. Significant Permit Modifications
ARM 17.8, Subchapter 12, Operating Permit Program §1227(1), (3)&(4)

1. The modification procedures set forth in 2 below must be used for any application requesting a significant modification of this permit. Significant modifications include the following:

    a. Any permit modification that does not qualify as either a minor modification or as an administrative permit amendment;

    b. Every significant change in existing permit monitoring terms or conditions;

    c. Every relaxation of permit reporting or recordkeeping terms or conditions that limit DEQ's ability to determine compliance with any applicable rule, consistent with the requirements of the rule; or

    d. Any other change determined by DEQ to be significant.

2. Significant modifications shall meet all requirements of ARM Title 17, Chapter 8, including those for applications, public participation, and review by affected states and the administrator, as they apply to permit issuance and renewal, except that an application for a significant permit modification need only address in detail those portions of the permit application that require revision, updating, supplementation or deletion.

3. The permit shield provided for in ARM 17.8.1214 shall extend to significant modifications.

L. Reopening for Cause
ARM 17.8, Subchapter 12, Operating Permit Program §1228(1)&(2)

This permit may be reopened and revised under the following circumstances:

1. Additional applicable requirements under the FCAA become applicable to the facility when the permit has a remaining term of 3 or more years. Reopening and revision of the permit shall be completed not later than 18 months after promulgation of the applicable requirement. No reopening is required under ARM 17.8.1228(1)(a) if the effective date of the applicable requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms or conditions have been extended pursuant to ARM 17.8.1220(12) or 17.8.1221(2);

2. Additional requirements (including excess emission requirements) become applicable to an affected source under the Acid Rain Program. Upon approval by the administrator, excess emission offset plans shall be deemed incorporated into the permit;

3. DEQ or the administrator determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emission standards or other terms or conditions of the permit; or

4. The administrator or DEQ determines that the permit must be revised or revoked and reissued to ensure compliance with the applicable requirements.

M. Permit Expiration and Renewal

ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(g), §1220(11)&(12), and §1205(2)(d)

1. This permit is issued for a fixed term of 5 years.

2. Renewal of this permit is subject to the same procedural requirements that apply to permit issuance, including those for application, content, public participation, and affected state and administrator review.

3. Expiration of this permit terminates the permittee's right to operate unless a timely and administratively complete renewal application has been submitted consistent with ARM 17.8.1221 and 17.8.1205(2)(d). If a timely and administratively complete application has been submitted, all terms and conditions of the permit, including the application shield, remain in effect after the permit expires until the permit renewal has been issued or denied.

4. For renewal, the permittee shall submit a complete air quality operating permit application to DEQ not later than 6 months prior to the expiration of this permit, unless otherwise specified. If necessary to ensure that the terms of the existing permit will not lapse before renewal, DEQ may specify, in writing to the permittee, a longer period for submission of the renewal application. Such written notification must be provided at least 1 year before the renewal application due date established in the existing permit.

N. Severability Clause

ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(i)&(l)

1. The administrative appeal or subsequent judicial review of the issuance by DEQ of an initial permit under this subchapter shall not impair in any manner the underlying applicability of all applicable requirements, and such requirements continue to apply as if a final permit decision had not been reached by DEQ.

2. If any provision of a permit is found to be invalid, all valid parts that are severable from the invalid part remain in effect. If a provision of a permit is invalid in one or more of its applications, the provision remains in effect in all valid applications that are severable from the invalid applications.

O. Transfer or Assignment of Ownership

ARM 17.8, Subchapter 12, Operating Permit Program §1225(2)&(4)

1. If an administrative permit amendment involves a change in ownership or operational control, the applicant must include in its request to DEQ a written agreement containing a specific date for the transfer of permit responsibility, coverage, and liability between the current and new permittee.

2. The permit shield provided for in ARM17.8.1214 shall not extend to administrative permit amendments.

P. Emissions Trading, Marketable Permits, Economic Incentives
ARM 17.8, Subchapter 12, Operating Permit Program §1226(2)

Notwithstanding ARM 17.8.1226(1) and (7), minor air quality operating permit modification procedures may be used for permit modifications involving the use of economic incentives, marketable permits, emissions trading, and other similar approaches, to the extent that such minor permit modification procedures are explicitly provided for in the Montana State Implementation Plan or in applicable requirements promulgated by the administrator.

Q. No Property Rights Conveyed
ARM 17.8, Subchapter 12, Operating Permit Program §1210(2)(d)

This permit does not convey any property rights of any sort, or any exclusive privilege.

R. Testing Requirements
ARM 17.8, Subchapter 1, General Provisions §105

The permittee shall comply with ARM 17.8.105.

S. Source Testing Protocol
ARM 17.8, Subchapter 1, General Provisions §106

The permittee shall comply with ARM 17.8.106.

T. Malfunctions
ARM 17.8, Subchapter 1, General Provisions §110

The permittee shall comply with ARM 17.8.110.

U. Circumvention
ARM 17.8, Subchapter 1, General Provisions §111

The permittee shall comply with ARM 17.8.111.

V. Motor Vehicles
ARM 17.8, Subchapter 3, Emission Standards §325

The permittee shall comply with ARM 17.8.325.

W. Annual Emissions Inventory
ARM 17.8, Subchapter 5, Air Quality Permit Application, Operation and Open Burning Fees §505 (STATE ONLY)

The permittee shall supply DEQ with annual production and other information for all emission units necessary to calculate actual or estimated actual amount of air pollutants emitted during each calendar year. Information shall be gathered on a calendar-year basis and submitted to DEQ by the date required in the emission inventory request, unless otherwise specified in this permit. Information shall be in the units required by DEQ.

X. Open Burning

ARM 17.8, Subchapter 6, Open Burning §604, 605, and 606

The permittee shall comply with ARM 17.8.604, 605, and 606.

Y. Montana Air Quality Permits

ARM 17.8, Subchapter 7, Permit, Construction and Operation of Air Contaminant Sources §745 and 764

1. Except as specified, no person shall construct, install, modify, or use any air contaminant source or stack associated with any source without first obtaining a permit from DEQ or Board. A permit is not required for those sources or stacks as specified by ARM 17.8.744(1)(a)-(k).

2. The permittee shall comply with ARM 17.8.743, 744, 745, 748, and 764.

3. ARM 17.8.745(1) specifies de minimis changes as construction or changed conditions of operation at a facility holding a Montana Air Quality Permit (MAQP) issued under Chapter 8 that does not increase the facility's potential to emit by more than 5 tons per year of any pollutant, except:

    a. Any construction or changed condition that would violate any condition in the facility's existing MAQP or any applicable rule contained in Chapter 8 is prohibited, except as provided in ARM 17.8.745(2);

    b. Any construction or changed conditions of operation that would qualify as a major modification under Subchapters 8, 9 or 10 of Chapter 8;

    c. Any construction or changed condition of operation that would affect the plume rise or dispersion characteristic of emissions that would cause or contribute to a violation of an ambient air quality standard or ambient air increment as defined in ARM 17.8.804;

    d. Any construction or improvement project with a potential to emit more than 5 tons per year may not be artificially split into smaller projects to avoid Montana Air Quality Permitting; or

    e. Emission reductions obtained through offsetting within a facility are not included when determining the potential emission increase from construction or changed conditions of operation, unless such reductions are made federally enforceable.

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

Z. National Emission Standard for Asbestos
40 CFR, Part 61, Subpart M

The permittee shall not conduct any asbestos abatement activities except in accordance with 40 CFR 61, Subpart M (National Emission Standard for Hazardous Air Pollutants for Asbestos).

AA. Asbestos
ARM 17.74, Subchapter 3, General Provisions and Subchapter 4, Fees

The permittee shall comply with ARM 17.74.301, *et seq*., and ARM 17.74.401, *et seq*. (State only).

BB. Stratospheric Ozone Protection – Servicing of Motor Vehicle Air Conditioners
40 CFR, Part 82, Subpart B

If the permittee performs a service on motor vehicles and this service involves ozone-depleting substance/refrigerant in the motor vehicle air conditioner (MVAC), the permittee is subject to all the applicable requirements as specified in 40 CFR 82, Subpart B.

CC. Stratospheric Ozone Protection – Recycling and Emission Reductions
40 CFR, Part 82, Subpart F

The permittee shall comply with the standards for recycling and emission reductions in 40 CFR 82, Subpart F, except as provided for MVACs in Subpart B.

1. Persons opening appliances for maintenance, service, repair, or disposal must comply with the required practices pursuant to §82.156;

2. Equipment used during the maintenance, service, repair or disposal of appliances must comply with the standards for recycling and recovery equipment pursuant to §82.158;

3. Persons performing maintenance, service, repair or disposal of appliances must be certified by an approved technical certification program pursuant to §82.161;

4. Persons disposing of small appliances, MVACs and MVAC-like (as defined at §82.152) appliances must comply with recordkeeping requirements pursuant to §82.166;

5. Persons owning commercial or industrial process refrigeration equipment must comply with the leak repair requirements pursuant to §82.156; and

6. Owners/operators of appliances normally containing 50 or more pounds of refrigerant must keep records of refrigerant purchased and added to such appliances pursuant to §82.166.

DD. Emergency Episode Plan

The permittee shall comply with the requirements contained in Chapter 9.7 of the State of Montana Air Quality Control Implementation Plan.

Each major source emitting 100 tons per year located in a Priority I Air Quality Control Region, shall submit to DEQ a legally enforceable Emergency Episode Action Plan (EEAP) that details how the source will curtail emissions during an air pollutant emergency episode. The industrial EEAP shall be in accordance with DEQ's EEAP and shall be submitted according to a timetable developed by DEQ, following Priority I reclassification.

EE. Definitions

Terms not otherwise defined in this permit or in the Definitions and Abbreviations Appendix B of this permit, shall have the meaning assigned to them in the referenced regulations.

APPENDICES

Appendix A. Insignificant Emission Units

Disclaimer: The information in this appendix is not State or Federally enforceable, but is presented to assist ExxonMobil, the permitting authority, inspectors, and the public.

Pursuant to ARM 17.8.1201(22)(a), an insignificant emission unit means any activity or emissions unit located within a source that: (i) has a potential to emit less than five tons per year of any regulated pollutant; (ii) has a potential to emit less than 500 pounds per year of lead; (iii) has a potential to emit less than 500 pounds per year of hazardous air pollutants listed pursuant to Section 7412 (b) of the FCAA; and (iv) is not regulated by an applicable requirement, other than a generally applicable requirement that applies to all emission units subject to Subchapter 12.

List of Insignificant Activities:

The following table of insignificant sources and/or activities was provided by ExxonMobil. Because there are no requirements to update such a list, the emissions units and/or activities may change from those specified in the table.

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
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

Appendix B. Definitions and Abbreviations

"Act" means the Clean Air Act, as amended, 42 U.S. 7401, *et seq*.

"Administrative permit amendment" means an air quality operating permit revision that:

(a) Corrects typographical errors;

(b) Identifies a change in the name, address or phone number of any person identified in the air quality operating permit, or identifies a similar minor administrative change at the source;

(c) Requires more frequent monitoring or reporting by ExxonMobil;

(d) Requires changes in monitoring or reporting requirements that DEQ deems to be no less stringent than current monitoring or reporting requirements;

(e) Allows for a change in ownership or operational control of a source if DEQ has determined that no other change in the air quality operating permit is necessary, consistent with ARM 17.8.1225; or

(f) Incorporates any other type of change that DEQ has determined to be similar to those revisions set forth in (a)-(e), above.

"Applicable requirement" means all the following as they apply to emission units in a source requiring an air quality operating permit (including requirements that have been promulgated or approved by DEQ or the administrator through rule making at the time of issuance of the air quality operating permit, but have future-effective compliance dates, provided that such requirements apply to sources covered under the operating permit):

(a) Any standard, rule, or other requirement, including any requirement contained in a consent decree or judicial or administrative order entered into or issued by DEQ, that is contained in the Montana state implementation plan approved or promulgated by the administrator through rule making under Title I of the FCAA;

(b) Any federally enforceable term, condition or other requirement of any Montana Air Quality Permit issued by DEQ under Subchapters 7, 8, 9 and 10 of this chapter, or pursuant to regulations approved or promulgated through rule making under Title I of the FCAA, including parts C and D;

(c) Any standard or other requirement under Section 7411 of the FCAA, including Section 7411(d);

(d) Any standard or other requirement under Section 7412 of the FCAA, including any requirement concerning accident prevention under Section 7412(r)(7), but excluding the contents of any risk management plan required under Section 7412(r);

(e) Any standard or other requirement of the acid rain program under Title IV of the FCAA or regulations promulgated thereunder;

(f) Any requirements established pursuant to Section 7661c(b) or Section 7414(a)(3) of the FCAA;

(g) Any standard or other requirement governing solid waste incineration, under Section 7429 of the FCAA;

(h) Any standard or other requirement for consumer and commercial products, under Section 7511b(e) of the FCAA;

(i) Any standard or other requirement for tank vessels, under Section 7511b(f) of the FCAA;

(j) Any standard or other requirement of the regulations promulgated to protect stratospheric ozone under Title VI of the FCAA, unless the administrator determines that such requirements need not be contained in an air quality operating permit;

(k) Any national ambient air quality standard or increment or visibility requirement under part C of Title I of the FCAA, but only as it would apply to temporary sources permitted pursuant to Section 7661c(e) of the FCAA; or

(l) Any federally enforceable term or condition of any air quality open burning permit issued by DEQ under subchapter 6.

"Department" means the Montana Department of Environmental Quality.

"Emissions unit" means any part or activity of a stationary source that emits or has the potential to emit any regulated air pollutant, or any pollutant listed under Section 7412(b) of the FCAA. This term is not meant to alter or affect the definition of the term "unit" for purposes of Title IV of the FCAA.

"Excess Emissions" means any visible emissions from a stack or source, viewed during the visual surveys, that meets or exceeds 15% opacity (or 30% opacity if associated with a 40% opacity limit) during normal operating conditions.

"FCAA" means the Federal Clean Air Act, as amended.

"Federally enforceable" means all limitations and conditions which are enforceable by the administrator, including those requirements developed pursuant to 40 CFR Parts 60 and 61, requirements within the Montana state implementation plan, and any permit requirement established pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51, Subpart I, including operating permits issued under an EPA approved program that is incorporated into the Montana state implementation plan and expressly requires adherence to any permit issued under such program.

"Fugitive emissions" means those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

"General air quality operating permit" or **"general permit"** means an air quality operating permit that meets the requirements of ARM 17.8.1222, covers multiple sources in a source category, and is issued in lieu of individual permits being issued to each source.

"Hazardous air pollutant" means any air pollutant listed as a hazardous air pollutant pursuant to Section 112(b) of the FCAA.

"Non-federally enforceable requirement" means the following as they apply to emission units in a source requiring an air quality operating permit:

(a) Any standard, rule, or other requirement, including any requirement contained in a consent decree, or judicial or administrative order entered into or issued by DEQ, that is not contained in the Montana state implementation plan approved or promulgated by the administrator through rule making under Title I of the FCAA;

(b) Any term, condition or other requirement contained in any Montana Air Quality Permit issued by DEQ under Subchapters 7, 8, 9 and 10 of this chapter that is not federally enforceable;

(c) Does not include any Montana ambient air quality standard contained in Subchapter 2 of this chapter.

"Permittee" means the owner or operator of any source subject to the permitting requirements of this subchapter, as provided in ARM 17.8.1204, that holds a valid air quality operating permit or has submitted a timely and complete permit application for issuance, renewal, amendment, or modification pursuant to this subchapter.

"Regulated air pollutant" means the following:

(a) Nitrogen oxides or any volatile organic compounds;

(b) Any pollutant for which a national ambient air quality standard has been promulgated;

(c) Any pollutant that is subject to any standard promulgated under Section 7411 of the FCAA;

(d) Any Class I or II substance subject to a standard promulgated under or established by Title VI of the FCAA; or

(e) Any pollutant subject to a standard or other requirement established or promulgated under Section 7412 of the FCAA, including but not limited to the following:

(i) Any pollutant subject to requirements under Section 7412(j) of the FCAA. If the administrator fails to promulgate a standard by the date established in Section 7412(e) of the FCAA, any pollutant for which a subject source would be major shall be considered to be regulated on the date 18 months after the applicable date established in Section 7412(e) of the FCAA;

(ii) Any pollutant for which the requirements of Section 7412(g)(2) of the FCAA have been met but only with respect to the individual source subject to Section 7412(g)(2) requirement.

"Responsible official" means one of the following:

(a) For a corporation: a president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representative is approved in advance by DEQ.

(b) For a partnership or sole proprietorship: a general partner or the proprietor; respectively.

(c) For a municipality, state, federal, or other public agency: either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (e.g., a regional administrator of the environmental protection agency).

(d) For affected sources: the designated representative in so far as actions, standards, requirements, or prohibitions under Title IV of the FCAA or the regulations promulgated thereunder are concerned, and the designated representative for any other purposes under this subchapter.

Abbreviations:

Alky	Alkylation
ARM	Administrative Rules of Montana
ASTM	American Society of Testing Materials
BACT	Best Available Control Technology
Btu	British Thermal Unit
CEMS	Continuous Emission Monitor System
CFRM	Continuous Flow Rate Monitor
CFR	Code of Federal Regulations
CO	carbon monoxide
COMS	Continuous Opacity Monitor System
DAS	Data Acquisition System
DEQ	Department of Environmental Quality
dscf	dry standard cubic foot
dscfm	dry standard cubic foot per minute
EEAP	Emergency Episode Action Plan
EPA	U.S. Environmental Protection Agency
EPA Method	Test methods contained in 40 CFR Part 60, Appendix A
EU	emission unit
FCAA	Federal Clean Air Act
FCC	Fluid Catalytic Cracker
FCCU	Fluid Catalytic Cracking Unit
FGR	Flue gas recirculation
gr	grains
HAP	hazardous air pollutant
HCBL	Hydrocracker
HF	hydrogen fluoride
HF#1	Hydrofiner #1
HF #2/3	Hydrofiners #2 and #3
H_2S	hydrogen sulfide
IEU	insignificant emissions unit
KBD	thousands of barrels per day
MACT	Maximum Achievable Control Technology
Method 5	40 CFR Part 60, Appendix A, Method 5
Method 9	40 CFR Part 60, Appendix A, Method 9
MMBtu	million British Thermal Units
NH_3	ammonia
NOx	oxides of nitrogen
NO_2	nitrogen dioxide
NSPS	New Source Performance Standard
NESHAPS	National Emission Standards for Hazardous Air Pollutant Sources
O_2	oxygen
OM&S	Oil Movement and Storage
OM&U	Oil Movement & Utilities
Pb	lead
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter of 10 microns or less
ppm	parts per million
ppm_{vd}	parts per million on a dry, volumetric basis

POFO	Powerformer
psi	pounds per square inch
scf	standard cubic feet
RATA	Relative Accuracy Test Audit
SIC	Source Industrial Classification
SLEB	Saturated Light Ends Unit
SO_2	sulfur dioxide
SOx	oxides of sulfur
SWSOH	sour water stripper overheads
TPY	tons per year
ULEB	Unsaturated Light Ends
U.S.C.	United States Code
VE	visible emissions
VOC	volatile organic compound

Appendix C. Notification Addresses

Compliance Notifications:

Montana Department of Environmental Quality
Air, Energy & Mining Division
Air Quality Bureau
P.O. Box 200901
Helena, MT 59620-0901

Montana Department of Environmental Quality
Air Quality Bureau
Airport Industrial Park
1371 Rimtop Dr.
Billings, MT 59105-1978

United States EPA
Air Program Coordinator
Region VIII, Montana Office
10 W. 15th Street, Suite 3200
Helena, MT 59626

Permit Modifications:

Montana Department of Environmental Quality
Air, Energy & Mining Division
Air Quality Bureau
P.O. Box 200901
Helena, MT 59620-0901

Office of Partnerships and Regulatory Assistance
Air and Radiation Program
US EPA Region VIII 8P-AR
1595 Wynkoop Street
Denver, CO 80202-1129

Appendix D. Air Quality Inspector Information

Disclaimer: The information in this appendix is not State or Federally enforceable but is presented to assist ExxonMobil, permitting authority, inspectors, and the public.

1. Direction to Plant:

The ExxonMobil Fuels and Lubricants Company Billings Refinery is located at 700 ExxonMobil Road, Billings, Montana. The Yellowstone River forms the northern and northeastern boundaries and interstate Highway 90 lies along the southern border.

2. All inspectors are required to be accompanied by an ExxonMobil employee or authorized representative.

3. Prior to entering the refinery, all visitors will be required to view a refinery entry video.

4. Safety Equipment Required:

The minimum personal protective equipment (PPE) requirements in the Refinery are:

- Approved hard hat
- Approved safety glasses with side shields
- Body Protection (flame retardant clothing)
- Foot protection (safety shoes or substantial leather shoes, no tennis shoes, vented footwear or sandals)

Additional PPE requirements, as posted in certain areas:

- Hearing protection in required areas (plot plans are posted in operating shelters).
- Hand protection is highly recommended
- Goggles
- Face shield as necessary to protect from a chemical splash hazard of airborne particles

Other requirements:

- Alkylation Unit entry requires special PPE requirements and procedures
- Respirator protection as required (must be clean shaven if respirator is required to do the job and be fit tested.)
- Vehicle seat belts are required in the plant
- Several safety showers/eye washes located throughout the refinery. They are green and white striped buildings

5. Facility Plot Plan:

A facility plot plan was submitted as part of the operating permit application on June 12, 1996. A copy is available in DEQ's records.

Appendix E. June 12, 1998, and March 17, 2000 Board Orders Adopting an SO_2 Control Plan

Although the hard copy of Appendix E has been removed from the permit, the contents of Appendix E, June 12, 1998, and March 17, 2000, Board Orders Adopting and SO_2 Control Plan remain as applicable requirements as stated in the Title V Operating Permit OP1564. To receive a hard copy of this appendix, please contact one of the following:

Montana Department of Environmental Quality
Air, Energy & Mining Division
Air Quality Bureau
1520 E. Sixth Ave.
P.O. Box 200901
Helena, Montana 59620-0901
Bureau Phone #: (406) 444-3490

OR

ExxonMobil Fuels and Lubricants Company
Billings Refinery
700 ExxonMobil Road
P.O. Box 1163
Billings, MT 59103-1163
Phone #: (406) 657-5361

Appendix F. CAM Plan for KCOB

The Coker is a pollutant-specific emission unit (PSEU) satisfying the following criteria (ARM 17.8.1503(1)):

(a) The unit is subject to particulate matter (PM) emission limits for industrial processes under ARM 17.8.310;

(b) The unit uses a control device (Bahco Multiclones) to achieve compliance with the PM emission limit; and

(c) The unit has potential pre-control device PM emissions greater than major source thresholds.

The Coker/KCOB and Bahco Multiclones are therefore subject to compliance assurance monitoring requirements set out in ARM 17.8.1504 through 17.8.1506 for PSEUs. As provided by ARM 17.8.1506(1), ExxonMobil shall use a Continuous Opacity Monitoring System (COMS) satisfying provisions of 40 CFR §51.214 and Appendix P of Part 51, and provisions of 40 CFR §60.13 and Appendix B of Part 60 to meet CAM requirements. As provided by ARM 17.8.1506(2), the COMS is therefore deemed to satisfy the general design criteria set out in ARM 17.8.1504 and 17.8.1505 and is presumptively acceptable compliance assurance monitoring under ARM 17.8.1506 and 17.8.1507.

CAM Plan: Particulate Matter Monitoring Approach for the Coker/KCOB

A. General Criteria for Monitoring Design (ARM 17.8.1504)	
1. Performance Indicator	KCOB Stack Opacity
2. Monitoring Approach	COMS satisfying provisions of 40 CFR §60.13 and Appendix B of Part 60 (ARM 17.8.1505(1)) [1]
3. Indicator Range: Reasonable assurance of compliance with PM standard	Zero to 20% Opacity, as indicated by COMS
4. Indicator Range: Indicated excursion from PM standard	Any rolling 3-hour period when the opacity measured by the COMS exceeds 20%, except during periods of startup, shutdown or malfunction. During periods of startup, shutdown or malfunction, ExxonMobil shall, to the extent practicable, maintain and operate the Coker/KCOB and the PM control equipment (Bahco Multiclones) in a manner consistent with good air pollution control practices. [2]
B. Performance Criteria and Evaluation Factors for Monitoring Design (ARM 17.8.1505 and ARM 17.8.1506)	
1. Performance specification	COMS design, installation, operation and performance conforms to Performance Specification 1 effective March 30, 1983 (48 FR 13322) (40 CFR Part 60, Appendix B) [1]
2. Performance Evaluation (new and modified equipment)	
3. Quality Assurance/Quality Control Procedures	
4. Frequency of Monitoring and Data Acquisition	
C. Reporting and Recordkeeping (ARM 17.8.1513)	
1. Monitoring Reports	Quarterly, as required by the Administrative Order [3]
2. Recordkeeping	As required by the Administrative Order [3]
D. Quality Improvement Plan (QIP) (ARM 17.8.1513)	
1. QIP	If required by the Department

[1] COMS satisfying provisions of 40 CFR §60.13 and Appendix B of Part 60 is presumptively acceptable and deemed to satisfy the general design criteria in ARM 17.8.1504 and ARM 17.8.1505 (ARM 17.8.1506(2) and ARM 17.8.1507(2))
[2] An excursion from the indicator range shall not be enforceable as a violation of the PM standard.
[3] Administrative Order signed on June 27, 1990; this requirement is "State Only"

Appendix G. Consent Decree Acid Gas/Hydrocarbon Flaring, Benzene Waste NESHAP and LDAR

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.

Control of Acid Gas Flaring Incidents

ExxonMobil Billings Refinery shall implement procedures for evaluating future Acid Gas Flaring Incidents (ExxonMobil Billings Refinery has no Sulfur Recovery Unit and therefore can have no Tail Gas Incidents). The procedures shall require a root cause analysis and may require corrective actions for some Acid Gas Flaring events.

Acid Gas Flaring Incidents Investigation and Reporting (Paragraph 80)
Following Acid Gas Flaring Incidents, ExxonMobil Billings Refinery shall submit a report that sets forth the information listed in Paragraph 80 of the Consent Decree.

Corrective Action (Paragraphs 80 - 81)
In response to any Acid Gas Flaring Incident, ExxonMobil Billings Refinery shall take corrective actions as practicable and as required in the referenced paragraphs to minimize the likelihood of a recurrence of the Root Cause and contributing causes of the Acid Gas Flaring Incident.

Control of Hydrocarbon Flaring Incidents

HC Flaring Incidents (Paragraph 92)
For Hydrocarbon Flaring Events, ExxonMobil Billings Refinery shall follow the same investigative and corrective action procedures as those outlined for Acid Gas Flaring Incidents. ExxonMobil Billings Refinery shall follow the same reporting procedures as those outlined for Acid Gas Flaring Incidents, except that ExxonMobil Billings Refinery shall only be required to submit such information in the Semiannual Reports.

Benzene Waste Operations NESHAP Program Enhancements

Refinery Compliance Status (Paragraph 98)
ExxonMobil Billings Refinery shall comply with the compliance option set forth at 40 CFR 61.342(e), the "6 BQ compliance option".

Annual Program (Paragraph 103)
ExxonMobil Billings Refinery shall provide for at least an annual review of process information for the Billings Refinery, including but not limited to construction projects, to ensure that all new benzene waste streams are included in the Refinery's TAB.

Laboratory Audits (Paragraph 104)
ExxonMobil Billings Refinery shall conduct audits of all laboratories that perform analyses of ExxonMobil's Benzene Waste NESHAP samples once every 2 calendar years.

Benzene Spills (Paragraph 105)
For each spill generating a "benzene waste" at the Billings Refinery, ExxonMobil shall include the benzene waste generated by the spill in the TAB, and as appropriate, account for such benzene waste in accordance with the applicable compliance option.

Training (Paragraph 106)
ExxonMobil Billings Refinery shall conduct initial annual training for all employees and contractors who draw benzene waste samples for Benzene Waste NESHAP purposes. "Refresher" training shall be performed on a three-year cycle.

Waste/Slop/Off-Spec Oil Management (Paragraph 107)
All waste management units handling non-exempt, non-aqueous benzene wastes, as defined in Subpart FF, shall meet the applicable control standards of Subpart FF. Aqueous streams shall be managed in accordance with the 6 BQ compliance option.

Sampling Under the 6 BQ Compliance Option (Paragraph 108)
ExxonMobil shall submit a BWON Sampling Plan for EPA approval and conduct quarterly sampling consistent with the Plan for the purpose of calculating quarterly, uncontrolled benzene quantities. ExxonMobil shall revise the plan if changes result in an inaccurate measure of the Refinery's quarterly benzene quantity in uncontrolled benzene waste streams. ExxonMobil shall use the information gathered to determine a quarterly benzene quantity in uncontrolled waste streams and to estimate a calendar year value for the Refinery.

Quarterly and Annual Estimations of Uncontrolled Benzene Quantity (Paragraph 110)
At the end of each calendar quarter, ExxonMobil shall calculate a quarterly uncontrolled benzene quantity and shall estimate a projected calendar year uncontrolled benzene quantity. ExxonMobil shall submit the uncontrolled benzene quantity in the Semi-Annual Reports.

Recordkeeping and Reporting Requirements (Paragraphs 113 - 114)
In addition to the reports referenced above, ExxonMobil Billings Refinery shall submit, as required, the reports set forth in Paragraph 113 and 114 of the Consent Decree.

Leak Detection and Repair ("LDAR") Program Enhancements

The following requirements are enhancements to the existing refinery LDAR program.

Written Refinery-Wide LDAR Program (Paragraph 117)
ExxonMobil Billings Refinery shall maintain and update a written refinery-wide program for compliance with all applicable federal LDAR regulations.

Training (Paragraph 118)
ExxonMobil Billings Refinery shall maintain a training program for all employees/contractors with LDAR responsibilities and all employee/contractors who have duties relevant to LDAR as described in Paragraph 118 of the Consent Decree.

Regular LDAR Audits (Paragraph 120)

ExxonMobil Billings Refinery shall complete regular (once every two (2) calendar years) Internal and Third-Party refinery-wide LDAR audits.

Implementation of Actions Necessary to Correct Non-Compliance (Paragraph 121)

If the results of any of the LDAR Audits identify any areas of non-compliance, ExxonMobil Billings Refinery shall implement, as soon as practicable, steps to correct the non-compliance and to prevent recurrences. After the completion of any LDAR Audit, ExxonMobil shall include in the next Consent Decree Semi-Annual Report a summary of the findings and schedule for implementing corrective actions.

Internal Leak Definition for Valves and Pumps (Paragraphs 122)

The permittee shall utilize an internal leak definition of 500 ppm for applicable valves and 2000 ppm for applicable pumps.

LDAR Monitoring Frequency (Paragraph 123)

ExxonMobil Billings Refinery shall monitor applicable pumps on a monthly basis. ExxonMobil Billings Refinery shall monitor applicable valves on a quarterly basis.

Reporting, Recording, Tracking, Repairing and Re-monitoring Leaks of Valves and Pumps Based on the Internal Leak Definitions (Paragraph 124)

ExxonMobil Billings Refinery may continue to report leak rates in valves and pumps against the applicable regulatory leak definition or use the lower internal leak definition. ExxonMobil Billings Refinery shall record, track, repair and re-monitor all leaks in excess of the internal leak definitions, shall make a first attempt at repair and remonitor the component within 5 calendar days after a leak is detected and either complete repairs and re-monitor leaks or place such component on the delay of repair list within 30 days after a leak is detected.

Monitoring After Turnaround or Maintenance. (Paragraph 125)

ExxonMobil shall have the option of monitoring affected components within process unit(s) after completing a maintenance, startup, or shutdown activity, and that monitoring activity shall not count as a scheduled monitoring activity for any components found to be leaking at a level between the internal leak definition and the applicable regulatory definition according to the provisions of Paragraph 125.

Initial Attempt at Repair on Certain Valves (Paragraph 126)

ExxonMobil Billings Refinery shall make a “initial attempt" at repair on those applicable valves for which monitoring indicates a reading greater than 200 ppm of VOCs. ExxonMobil Billings Refinery shall re-monitor all valves that LDAR personnel attempted to repair within 5 days.

Electronic Monitoring, Storing, and Reporting of LDAR Data (Paragraph 127)

ExxonMobil Billings Refinery shall maintain an electronic database for storing and reporting LDAR data. ExxonMobil Billings Refinery shall use electronic data collection devices during LDAR monitoring and transfer the data from electronic data-logging devices to the electronic database by the next business day. Collected monitoring data shall include a time and date stamp, and identification of the instrument and operator. ExxonMobil Billings Refinery may use paper logs as dictated in the Consent Decree and shall record the technician, the date, the monitoring starting and ending times, all monitoring readings, and the identification of the monitoring equipment. ExxonMobil Billings Refinery shall use its best efforts to transfer any manually recorded monitoring data to the electronic database within 7 days of monitoring event.

QA/QC of LDAR Data (Paragraph 128)
ExxonMobil Billings Refinery, or a third-party contractor retained by ExxonMobil Billings Refinery, shall implement procedures for quality assurance/quality control ("QA/QC") reviews of all data generated by LDAR monitoring technicians.

Calibration/Calibration Drift Assessment (Paragraph 129)
ExxonMobil Billings Refinery shall calibrate LDAR monitoring equipment using methane as the calibration gas and in accordance with Method 21. ExxonMobil shall conduct twice daily calibration drift assessments at the internal leak definition with one such re-check occurring at the end of the monitoring shift. If any calibration drift assessment shows a negative drift of more than 10%, ExxonMobil Billings Refinery shall re-monitor all valves/pumps with a readings greater than 100/500 ppm, that were monitored since the last calibration/calibration drift assessment.

Delay of Repair (Paragraph 130)
Before placing a component on the "delay of repair (DOR)" list, ExxonMobil Billings Refinery shall require sign-off by the unit supervisor that the component qualifies for delayed repair. ExxonMobil shall conduct regular LDAR monitoring on the DOR equipment and shall use best efforts to repair leaking pumps. For applicable valves leaking at 10,000 ppm or greater, ExxonMobil shall use the "drill and tap" repair method as required in Paragraph 130 prior to placing the valve on DOR.

Chronic Leakers (Paragraph 131)
A valve shall be classified as a "chronic leaker" if it leaks above 5,000 ppm twice in any consecutive four quarters. Following the identification of a "chronic leaker", ExxonMobil shall perform repairs on the chronic leaker during the next process unit turnaround.

Alternate Leak Detection Method (Paragraph 132)
With EPA's prior written approval, ExxonMobil may begin using an alternate leak detection method – such as "Smart LDAR" technology.

Recordkeeping and Reporting Requirements (Paragraph 133)
In the Semi-Annual Reports submitted pursuant to Section IX of the Consent Decree, ExxonMobil shall include as required: a copy of the LDAR Program Description; a certification that LDAR training was implemented; an identification of the position responsible for LDAR performance; a certification that the lower leak definitions and increased monitoring frequencies have been implemented; a certification of the implementation of the "initial attempt" to repair program; a certification of the implementation of QA/QC procedures for review of data generated by LDAR technicians as required by Paragraph 128 of the Consent Decree; a certification of the implementation of the calibration drift assessment procedures and a certification of the implementation of the "delay of repair" procedures.

In the first Semi-Annual Report submitted each year, ExxonMobil shall identify and supply specific information on any LDAR Audit conducted in the previous calendar year.

In the reports due under 40 C.F.R. § 63.654, ExxonMobil shall include: a list of the process units monitored; the number of valves and pumps in each process unit; the number of valves and pumps monitored; the number of valves and pumps found leaking; the number of "difficult to monitor" equipment monitored; the projected month of the next monitoring for a unit; a list of equipment and the date for each "delay of repair"; the number of repairs not attempted within the required times; the number of initial attempts at repair not completed within 5 days; the number of chronic leaker repairs not completed at the next process unit turnaround; and the number of extraordinary repairs not completed within 15 and 30 days.

Appendix H. Root Cause Failure Analysis Requirements

<u>**Definitions**</u>

Acid Gas or AG shall mean any gas that contains hydrogen sulfide and is generated at a refinery by the regeneration of an amine scrubber solution but does not mean Tail Gas.

Acid Gas Flaring Device or AG Flaring Device shall mean the devices identified as the Flare and Turnaround Flare that are used to combust Acid Gas and/or Sour Water Stripper Gas. The term "Acid Gas Flaring Device" does not include facilities in which gases are combusted to produce sulfur or sulfuric acid.

Acid Gas Flaring Incident or AG Flaring Incident shall mean the continuous or intermittent combustion of Acid Gas and/or Sour Water Stripper Gas from one or more AG Flaring Devices at a covered Refinery that result in the emission of sulfur dioxide equal to, or in excess of, 500 pounds in any 24-hour period. Where such continuous or intermittent combustion from one or more AG Flaring Devices continues into subsequent, contiguous, non-overlapping 24-hour periods, and sulfur dioxide equal to, or in excess of, 500 pounds is emitted in each subsequent, contiguous, non-overlapping 24-hour period, then only one AG Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping 24-hour periods are measured from the initial commencement of AG Flaring within the AG Flaring Incident.

Hydrocarbon Flaring or HC Flaring shall mean the combustion of refinery-generated gases, except for Acid Gas and/or Sour Water Stripper Gas and/or Tail Gas, in a Hydrocarbon Flaring Device. Nothing in this definition shall be construed to modify, limit, or affect EPA's authority to regulate the flaring of gases that do not fall within this definition.

Hydrocarbon Flaring Device or HC Flaring Device shall mean the devices listed as the Flare and Turnaround Flare that are used by the ExxonMobil Billings Refinery to control (through combustion) any excess volume of a refinery-generated gas other than Acid Gas and/or Sour Water Stripper Gas and/or Tail Gas.

Hydrocarbon Flaring Incident or HC Flaring Incident shall mean the continuous or intermittent flaring of refinery-generated gases, except for Acid Gas or Sour Water Stripper Gas or Tail Gas, in a Hydrocarbon Flaring Device that results in the emission of sulfur dioxide equal to or greater than five hundred (500) pounds in a 24-hour period. Where such continuous or intermittent flaring from a Hydrocarbon Flaring Device continues into subsequent, contiguous, non-overlapping 24-hour period(s), and sulfur dioxide equal to, or in excess of, five hundred (500) pounds is emitted in each subsequent, contiguous, non-overlapping 24-hour period(s), then only one HC Flaring Incident shall have occurred. Subsequent, contiguous, non-overlapping 24-hour periods are measured from the initial commencement of flaring within the HC Flaring Incident.

Sour Water Stripper Gas or SWS Gas shall mean the gas produced by the process of stripping or scrubbing refinery sour water.

Analysis Content

<u>**Acid Gas and Hydrocarbon Flaring Incident Root Cause Analysis**</u>
The facility shall investigate each acid gas flaring incident and hydrocarbon flaring incident within 45 days of the end of the incident and record the results of the investigation. The investigation shall include (i) date and time the acid gas flaring incident started and ended; (ii) an estimate of the quantity of the SO_2 emissions, including supporting calculations; (iii) steps taken to limit the duration

and/or quantity of SO_2 emissions; (iv) an analysis of the root cause of the incident; and (v) an analysis of corrective actions, if any, that are available to reduce the likelihood of a recurrence of the incident from the same root cause. (vi) For any corrective actions taken, the facility shall document corrective actions taken within the 45 days following the incident and a schedule for completion of any other corrective actions proposed to be completed. Records of such investigations and corrective actions completed shall be kept onsite.

A single root cause analysis may be used for hydrocarbon flaring root causes that occur routinely. Where the site has previously analyzed hydrocarbon incidents related to startup and shutdown, it may refer to those analyses when evaluating later incidents. Records of such investigations and corrective actions shall be kept on site.

To the extent that a hydrocarbon flaring incident has as its root cause the bypass of a flare gas recovery system for safety or maintenance reasons, describe only the hydrocarbon flaring incident and list the date, time, and duration of such incident. Records shall be kept on site.

Transition to NSPS Ja

If a flare and Turnaround Flare become subject to NSPS Ja, those flares are no longer required to follow the root cause failure analysis requirements within Appendix H. The flares shall follow the requirements of NSPS Ja.