



November 17th, 2023

Phillips 66 Company
Billings Refinery
P.O. Box 30198
Billings, MT 59107-0198

Sent via email: Matt.Evans@p66.com

RE: Final Permit Issuance for MAQP #2619-45

Dear Mr. Evans:

Montana Air Quality Permit (MAQP) #2619-45 is deemed final as of November 17th, 2023, by DEQ. This permit is for Phillips 66 Billings Refinery, a petroleum refinery. All conditions of the Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

Conditions: See attached.

For DEQ,

A handwritten signature in black ink that reads "Julie A. Merkel".

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

A handwritten signature in black ink that reads "Tim Gauthier".

Tim Gauthier
Air Quality Engineering Scientist
Air Quality Bureau
(406) 444-2467

MONTANA AIR QUALITY PERMIT

Issued to: Phillips 66 Company
Billings Refinery
P.O. Box 30198
Billings, MT 59107-0198

MAQP: #2619-45
Application Complete: 9/22/2023
Preliminary Determination: 10/16/2023
Department Decision: 11/01/2023
Permit Final: 11/17/2023
AFS #: 111-0011

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to Phillips 66 Company (Phillips 66), pursuant to Sections 75-2-204, 211, 213, and 215 of the Montana Code Annotated (MCA), as amended, and the Administrative Rules of Montana (ARM) 17.8.740, *et seq.*, and 17.8.801, *et seq.*, as amended, for the following:

SECTION I: Permitted Facility

A. Plant Location

Phillips 66 operates a petroleum refinery located at 401 South 23rd Street, Billings, Montana, in the NW¹/₄ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. A complete list of the permitted equipment for Phillips 66 is contained in Section I.A of the Permit Analysis.

B. Refinery Operations

Phillips 66 operates a petroleum refinery, with those operations covered under this MAQP. The refinery operations at the source were provided a separate Title V Operating Permit for purposes of facilitating Responsible Official responsibilities in line with management structure. For Prevention of Significant Determination (PSD)/New Source Review (NSR), New Source Performance Standards (NSPS), Maximum Achievable Control Technology (MACT) permit review purposes and Title V applicability purposes, the Refinery Operations are considered the same source as the Phillips 66 Pipeline, LLC Transportation Operations and Jupiter Sulphur, LLC Operations.

C. Transportation Operations – Phillips 66 Pipeline, LLC

Phillips 66 owns Phillips 66 Pipeline, LLC, which operates loading rack operations adjacent to the refinery operations that are covered under this MAQP. The portions of the source under the management of the Transportation Operations were provided a separate Title V Operating Permit for purposes of facilitating Responsible Official responsibilities in line with management structure. For PSD/NSR, NSPS, MACT, and Title V applicability purposes, the Transportation Operations, Refinery Operations, and Sulfur Recovery Operations are considered one source.

D. Sulfur Recovery Operations - Jupiter Sulphur, LLC (Jupiter)

Jupiter is a sulfur recovery operation within the petroleum refinery area described above at 2201 7th Avenue South, Billings, Montana. This operation is a joint venture, of which Phillips 66 is a partner. With physical changes required at the Jupiter plant in order for

operational goals and changes within the refinery to be achieved, air quality permit actions have been submitted and accepted as being one source. The Jupiter sulfur recovery operations consists of three sulfur recovery units. The Jupiter operations are covered under this MAQP and are currently a part of the Refinery Operations Title V Operating Permit. For PSD/NSR, NSPS, MACT, and Title V applicability purposes, the Jupiter operations are considered part of the same source as the Transportation and Refinery Operations.

E. Current Permit Action

On September 5th, 2023, DEQ received from Phillips 66 an application to modify their MAQP based on changes to the refinery under the Vacuum Improvement Project (VIP). VIP included improvements in crude unit distillation capabilities and wastewater treatment facilities, an increase in hydrogen production capabilities, and an expansion of the Jupiter Sulphur, LLC (Jupiter) sulfur recovery facilities at the existing refinery.

With this submittal, Phillips 66 is proposing to include two new NO_x and SO₂ emission limitations for two of the affected units affected by the VIP (i.e. Large Crude Unit Heater H-24 and Vacuum Furnace H-17). This submittal keeps VIP a non-major modification for NO_x and SO₂ under the PSD program.

In addition, Phillips 66 is requesting the following:

- Revise the SO₂ emission limitation addressed in MAQP #2619-39 for the fluid catalytic cracking unit (FCCU). DEQ did not move forward with the requested change to the FCCU SO₂ requested emission limit change.
- Clarify the SO₂ emission limitation addressed in MAQP #2619-32 for the Jupiter Sulfur Recovery Unit (SRU) Main Stack #2. This change simply would revise the percent oxygen limit from 3 percent to zero percent to better align with standard NSPS oxygen correction factors.
- Removal of Compressor C-23 as well as its permit terms and conditions.
- Clarify the applicability of certain new source performance standards (NSPS) to further streamline requirements for refinery operations.

SECTION II: Conditions and Limitations

A. Applicable Requirements

1. Phillips 66 shall comply with all applicable requirements of ARM 17.8.340, which references 40 Code of Federal Regulations (CFR) Part 60, Standards of Performance for New Stationary Sources (NSPS):
 - a. Subpart A - General Provisions applies to all equipment or facilities subject to an NSPS Subpart as listed below.
 - b. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units shall apply to all affected boilers at the facility which were constructed after June 19, 1984, are larger than 100 million British thermal units per hour (MMBtu/hr), and combust fossil fuel. Phillips 66 shall comply with all applicable requirements of

Subpart Db, for all affected boilers at the facility which includes Boilers B-5 and B-6.

- c. Subpart J - Standards of Performance for Petroleum Refineries shall apply to, but not be limited to:
 - i. All of the heaters and boilers at the Phillips 66 refinery not subject to or electing to comply with Subpart Ja (ARM 17.8.749);
 - ii. The Fluid Catalytic Cracking Unit (FCCU) (CO, SO₂, PM, and opacity provisions) (ARM 17.8.749); and
 - iii. Any other affected equipment.
- d. Subpart Ja - Standards of Performance for Petroleum Refineries for which Construction, Reconstruction, or Modification commenced after May 14, 2007, shall apply to, but not be limited to:
 - i. The Delayed Coking Unit (Delayed Coker) (ARM 17.8.340 and 40 CFR 60 Subpart Ja)
 - ii. Refinery Main Plant Relief Flare (ARM 17.8.340 and 40 CFR 60 Subpart Ja)
 - iii. Jupiter SRUs and Flare (ARM 17.8.340, and 40 CFR 60 Subpart Ja)
 - iv. The following process heaters: Vacuum Furnace H-17, Large Crude Unit Heater H-24, and the No. 3 H₂ Plant Reformer Heater H-8501 (ARM 17.8.340 and 40 CFR 60 Subpart Ja).
 - v. Any other affected equipment
- e. Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids shall apply to all petroleum storage vessels for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984, for requirements not overridden by 40 CFR 63 Subpart CC.

These requirements shall be as specified in 40 CFR 60.110a through 60.115a. The affected tanks include, but are not limited to, the following:

Tank ID

- i. T-100*
- ii. T-101*
- iii. T-102

* *Currently exempt from all emission control provisions due to vapor pressure of materials stored.*

** *MACT Refinery I Group 1 storage vessels subject to 40 CFR 63 Subpart CC and 40 CFR Subpart Ka, are only required to comply with the*

requirements of 40 CFR 63 Subpart CC according to 40 CFR 63.660(n)(5). Additionally, MACT Refinery Group 1 tanks subject to 40 CFR 63 Subpart CC shall comply with the requirements of 40 CFR 63 Subpart WW per 40 CFR 63.660.

- f. Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984, for requirements not overridden by 40 CFR 63 Subpart CC. These requirements shall be as specified in 40 CFR 60.110b through 60.117b. In accordance with 40 CFR 60.110b(e) the storage vessels that meets the criteria described in 40 CFR 60.110b(e) may satisfy the requirements of 40 CFR Subpart Kb by complying with 40 CFR 63 Subpart WW, as applicable. The affected tanks include, but are not limited to, the following:

Tank ID

- i. T-35
- ii. T-72
- iii. T-107*
- iv. T-110
- v. T-0851 (No. 5 HDS Feed Storage Tank)
- vi. T-1102 (Crude Oil Storage Tank)
- vii. T-2909 (LSG Tank)

* *Currently exempt from all emission control provisions due to vapor pressure of materials stored.*

** *MACT Refinery Group 1 tanks subject to 40 CFR 63 Subpart CC shall comply with the requirements of 40 CFR 63 Subpart WW per 40 CFR 63.660.*

- g. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006 shall apply to the following compressors:

- i. C-26, FCCU Wet Gas Compressor
- ii. C-3901, Coker Unit Wet Gas Compressor
- iii. C-5301, Flare Gas Recovery Unit Liquid Ring Compressor
- iv. C-5302, Flare Gas Recovery Unit Liquid Ring Compressor
- v. C-8301, Cryo Unit Inlet Gas Compressor
- vi. C-8302, Cryo Unit Refrigerant Compressor
- vii. C-8303, Cryo Unit Regeneration Gas Compressor
- viii. C-9401, No. 1 H₂ Plant Feed Gas Compressor

- ix. C-9701, No. 2 H₂ Plant Feed Gas Compressor
- h. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006 shall apply to the following compressors which are in hydrogen service:
 - i. C-8401, No. 4 HDS Makeup/Recycle H₂ Compressor
 - ii. C-7401, H₂ Makeup/Reformer H₂ Compressor
 - iii. C-9501, Makeup/Recycle Gas Compressor
 - iv. C-27, Butamer Combined Hydrogen Compressor
 - v. C-19, No. 2 Reformer Recycle Hydrogen Compressor
 - vi. C-18, No. 2 HDS Recycle Hydrogen Compressor
 - vii. C-8402, Makeup/Recycle Compressor
- i. Reserved
- j. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006 shall apply to, but not be limited to the group of all equipment (as defined in 40 CFR 60.591a) in the following process units:
 - i. Delayed Coker Unit
 - ii. Cryogenic Unit
 - iii. Hydrogen Membrane Unit
 - iv. Gasoline Merox Unit
 - v. Crude Units
 - vi. Gas Oil Hydrotreater Unit (consisting of a reaction section, fractionation section, and an amine treating section)
 - vii. No. 1 H₂ Unit (22.0-million standard cubic feet per day (MMscfd) hydrogen plant feed system)
 - viii. Alkylation Unit (including the and the Alkylation Unit Depropanizer Project)
 - ix. #3 Sour Water Stripper (SWS) Unit

- x. Fugitive components associated with boilers #B-5 and #B-6
 - xi. Fugitive components associated with the No.2 H₂ Unit and the No.5 HDS Unit
 - xii. FCCU
 - xiii. No. 3 H₂ Plant, and
 - xiv. Any other applicable equipment constructed or modified after November 7, 2006
- k. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems, shall apply to, but not be limited to:
- i. Coker unit drain system
 - ii. Desalter wastewater break tanks
 - iii. Gas oil hydrotreater oily water sewer drain system
 - iv. No. 1 H₂ Plant (22.0-MMscfd H₂ plant)
 - v. Alkylation Unit Butane Defluorinator oily water sewer drain system
 - vi. Alkylation Unit Depropanizer oily water sewer drain system
 - vii. #3 SWS Unit oily water sewer drain system
 - viii. South Tank Farm oily water sewer drain system
 - ix. Tank T-4523 (wastewater surge tank)
 - x. API Separators, including the slop oil vessel T-4526 and Sludge Hopper T-4527.
 - xi. No. 2 H₂ Plant and the No. 5 HDS Unit new individual oily water drain system
 - xii. No. 3 H₂ Plant, and
 - xiii. Any other applicable equipment, for requirements not overridden by 40 CFR 63 Subpart CC
- l. Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines shall apply to, but not be limited to diesel-fired engines used for operation of the Backup Coke Crusher,

the Backup Firepump Engine, and the Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps.

2. Phillips 66 shall comply with all applicable requirements of ARM 17.8.341, which references 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAP):
 - a. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP subpart as listed below.
 - b. Subpart FF - National Emission Standards for Benzene Waste Operations shall apply to, but not be limited to, all new or recommissioned wastewater sewer drains associated with the Alkylation Unit Depropanizer Project, the Refinery's existing individual drain and sewer systems (except the Alky grandfathered sewers), the new individual drain system for the No. 3 H₂ Plant, and Tanks 34 and 35.
 - c. Subpart M - National Emission Standard for Asbestos shall apply to, but not be limited to, the demolition and/or renovation of regulated asbestos containing material.
3. Phillips 66 shall comply with all applicable requirements of ARM 17.8.342, which reference 40 CFR Part 63, NESHAP for Source Categories, including the reporting, recordkeeping, testing, and notification requirements:
 - a. Subpart A - General Provisions, applies to all equipment or facilities subject to a NESHAP for source categories subpart as listed below.
 - b. Subpart Q – National Emissions Standards for Hazardous Air Pollutants for Industrial Process Cooling Towers applies only if chromium based water treatment chemicals are used. The rule bans chromium based water treatment chemicals from being used.
 - c. Subpart R - National Emission Standards for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations), shall apply to, but not be limited to, the bulk loading rack.
 - d. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (Refinery MACT I), shall apply to, but not be limited to, Miscellaneous Process Vents; Equipment Leaks; Wastewater Streams; Heat Exchange Systems, and Storage Vessels including but not limited to:

Group 1:

- Crude Oil Storage Tanks #1, #2, and T-1102
- Gasoline, Naphtha, and Other Storage Tanks: #3, #5, #7, #9, #11, #12, #16, #21, #41, #42, #45, #46, #49, #52, #55, #72, #75, #80, #86, #87, #102, #110, #851, #2909

Group 2:

- Asphalt and PMA Storage Tanks #62, #100, #101 & #3201
 - Jet A, Distillate, and Diesel Storage Tanks #8, #10, #14, #20, #33, #47, #48, #53, #54, #57, #74,
 - Residual and Fuel Oil Storage Tanks #6, #17, #39, #40, #69, #70, #81, #107, #T-0852
 - Other Storage Tanks #13, #18, #32, #59, #60, #82, #88, #116, #801
 - Organic Liquid Distribution (OLD) MACT:
 - Tank #109
- e. Subpart UUU - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (Refinery MACT II), shall apply to, but not be limited to, the SRUs, the FCCU, and Catalytic Reforming Unit #2. Subpart UUU does not apply to the Catalytic Reforming Unit #1 as long as the reformer is dormant or the catalyst is regenerated off-site.
- f. Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines shall apply to, but not be limited to the diesel-fired engine used for operation of the Backup Coke Crusher, the Cryo Backup Air Compressor engine, the Boiler House Air Compressor engine, the Pump for Storm Water to Holding Pond engine, the Backup Firepump Engine, the Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps, and the Boiler House Backup Air Compressor engine.
- g. Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. Applicability includes the boilers and fuel gas combustion units.
- h. 40 CFR 63 Subpart WW – National Emission Standards for Storage Vessels (Tanks) – Control Level 2. Applicability includes storage vessels for which another Subpart references the use of this Subpart for such air emission control.

4. Phillips 66 shall comply with the provisions of 40 CFR 82 Subpart F, Recycling and Emission Reduction as applicable (ARM 17.8.749).

B. Emission Control Requirements

Phillips 66 shall install, operate, and maintain the following emission control equipment to provide the maximum air pollution control for which it was designed (ARM 17.8.752):

1. The Refinery Main Plant Relief flare must be equipped and operated with a steam injection system (ARM 17.8.752). The flare tip is to be based at a minimum of 142-feet plus or minus 2 feet elevation (ARM 17.8.749). Phillips

66 shall minimize SO₂ flaring activity by installing and operating flare gas recovery systems on the Refinery Main Plant Relief flare (ARM 17.8.749).

2. The Jupiter flare must be equipped and operated with a steam injection system (ARM 17.8.752). The flare tip is to be based at a minimum of 213-feet plus or minus 3 feet elevation (ARM 17.8.749).
3. Phillips 66 shall utilize, as needed, CO combustion promoter, NO_x reducing catalyst additive, and SO₂ reducing catalyst additive in the FCCU catalyst regenerator, hydrotreating of the feed to the FCCU, as well as CO, NO_x, SO₂, and O₂ CEMS, to control CO, NO_x, and SO₂ to required emissions limitations (ARM 17.8.752, ARM 17.8.819).
4. Phillips 66 shall utilize 3-stage cyclones, followed by a filter or 4th stage cyclone, to control total filterable particulate emissions from the FCCU catalyst regenerator to required emissions limitations (ARM 17.8.752, ARM 17.8.819).
5. Storage tank #49 shall be equipped with an internal floating roof with a double rim seal, liquid-mounted seal, or mechanical shoe seal system for VOC loss control (ARM 17.8.752).
6. Storage tanks #4510 and #4511 shall be equipped with internal floating roofs with double rim seals or a liquid-mounted seal system for VOC loss control (ARM 17.8.752).
7. All systems within the Phillips 66 refinery and Jupiter sulfur recovery operations (modifications) shall be totally enclosed and controlled such that any pollutant generated does not vent to atmosphere, except as expressly allowed in this permit (ARM 17.8.749).
8. The large crude unit heater (H-24), recycle hydrogen heater (H-8401), fractionator feed heater (H-8402), No. 1 H₂ plant reformer heater (H-9401), and No. 2 H₂ Plant Reformer Heater (H-9701) shall be equipped with Ultra Low NO_x Burners (ULNB) (ARM 17.8.752).
9. The Claus SRU Incinerator (F-304) shall be equipped with LNB (ARM 17.8.752 and ARM 17.8.819).
10. The coker heater (H-3901) shall be equipped with LNB.¹
11. Boilers #B-5 and #B-6 shall be equipped with ULNB (ARM 17.8.752, ARM 17.8.819).
12. No. 5 HDS Charge Heater, No. 5 HDS Stabilizer Reboiler Heater, and No.3 Hydrogen Plant Heater shall be equipped with ULNB (ARM 17.8.752, ARM 17.8.819).

¹ The low NO_x burners for the coker heater are a requirement of the coker Permit #2619 issued April 19, 1990.

13. The separator bays of the two API Separator Tanks shall be covered and sealed and the vapor from these bays shall be routed to a VOC control device to control VOC emissions with at least a 95% control efficiency (ARM 17.8.752). The VOC control device shall be an activated carbon canister (ARM 17.8.49).
14. The bulk loading gasoline and distillates loading rack shall be operated and maintained as follows:
 - a. Phillips 66's collected vapors shall be routed to the Vapor Combustor Unit (VCU) at all times. In the event the VCU was inoperable, Phillips 66 may continue to load only distillates with a Reid vapor pressure of less than 27.6 kilopascals, provided DEQ is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.752).
 - b. Loading of cargo tanks shall be restricted to the use of submerged fill and dedicated normal service (ARM 17.8.749).
15. Jupiter shall vent off-gas from the ASD unit operation to a sulfur boiler except during malfunction or maintenance conditions, when the off-gases would be vented to the Jupiter SRU flare (ARM 17.8.749).
16. When a temporary natural gas-fired boiler is necessary, Phillips 66 shall operate the temporary natural gas-fired boiler for no longer than 8 weeks per rolling 12-month period. The temporary boiler shall not exceed a firing rate of 51 MMBtu/hr, and shall only be used during refinery turnarounds (ARM 17.8.749).
17. Phillips 66 shall operate and maintain an amine-based chemical absorption system on the refinery fuel gas system (ARM 17.8.752 and ARM 17.8.819).
18. The Claus SRU shall be equipped with a TGTU (ARM 17.8.752 and ARM 17.8.819).
19. SRU #2 shall be considered subject to 40 CFR 60 Subpart Ja conditions as a modified unit (ARM 17.8.749).
20. SRU #3 shall be equipped with an oxidation tail gas scrubber process (ARM 17.8.752).
21. SRU #1, #2, and #3 shall each be equipped with the following, downstream of the sulfur oxidizers: 2 wet scrubbers in series, followed by 3 parallel vent gas filters (each filter vessel contains four candle filter elements in a nested filter-in-filter design) (ARM 17.8.752 and ARM 17.8.819).
22. The New Cooling Tower installed as part of the 2022 Projects (MAQP 2619-39), Cooling Tower CWT5, and the Cooling Tower CT-615 A/B/C, shall be equipped with high efficiency drift eliminators with a design drift rate not to exceed 0.0010% (ARM 17.8.752). Phillips 66 shall maintain documentation

of vendor/manufacturer supplied documentation demonstrating design drift rate, on-site and available upon request (ARM 17.8.749).

C. Emission Limitations

1. Total refinery and sulfur recovery facility emissions shall not exceed the following (ARM 17.8.749, unless otherwise noted):
 - a. Jupiter SRU Flare²
 - i. SO₂ Emissions - 25.00 lbs/hr, 0.30 tons/day.
 - ii. Hydrogen Sulfide (H₂S) content of the flare gas (and pilot gas) burned shall not exceed 0.10 grains/dry standard cubic foot (gr/dscf) (ARM 17.8.749), with the exception of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja).
2. Total SO₂ emissions from the Jupiter Main Stack No. 1 plus the Jupiter SRU flare shall not exceed 109.5 TPY (rolling 12-month average) (ARM 17.8.749)
3. Emissions from SRU #1 and SRU #2 combined (Jupiter Main Stack No. 1), shall not exceed the following:
 - a. Total filterable particulate: 2.0 lb/hr (ARM 17.8.752, ARM 17.8.749, ARM 17.8.819)
 - b. PM₁₀ (filterable + condensable): 4.0 lb/hr (ARM 17.8.749)
 - c. PM_{2.5} (filterable + condensable): 4.0 lb/hr (ARM 17.8.749)
 - d. SO₂: 167 ppmvd (parts per million on a dry, volumetric basis) at 0% O₂ on a 12-hour rolling average basis (ARM 17.8.752, ARM 17.8.819, ARM 17.8.749)
 - e. Ammonia: 13.36 lb/hr (ARM 17.8.749)
 - f. NO_x: 14.84 lb/hr (ARM 17.8.749, ARM 17.8.752, ARM 17.8.819)
 - g. CO: 4.22 lb/hr (ARM 17.8.752, ARM 17.8.819, ARM 17.8.749)
 - h. Opacity: 20% averaged over any 6 consecutive minutes (ARM 17.8.304)
4. SRU #3 shall have its own emissions stack, named Jupiter Main Stack No. 2 (ARM 17.8.749). Emissions from Jupiter Main Stack No. 2 shall not exceed:
 - a. Total filterable particulate: 2.0 lb/hr (ARM 17.8.752, ARM 17.8.749, ARM 17.8.819)
 - b. PM₁₀ (filterable + condensable): 4.0 lb/hr (ARM 17.8.749)
 - c. PM_{2.5} (filterable + condensable): 4.0 lb/hr (ARM 17.8.749)
 - d. SO₂: 167 ppmvd at 0% O₂ on a 12-hour rolling average basis (ARM 17.8.752, ARM 17.8.749)
 - e. Ammonia: 13.36 lb/hr (ARM 17.8.749)

² Emissions occur only during times that the ATS plant is not operating and/or during abnormal process condition, process upsets, and/or malfunctions.

- f. NO_x: 14.84 lb/hr (ARM 17.8.749, ARM 17.8.752, ARM 17.8.819)
 - g. CO: 4.22 lb/hr (ARM 17.8.752, ARM 17.8.819, ARM 17.8.749)
 - h. Opacity: 20% averaged over any 6 consecutive minutes (ARM 17.8.304)
5. SRU #1, #2, and #3, combined, shall be limited to (ARM 17.8.749):
- a. SO₂: 50 tons per year on a 12-month rolling sum basis.
 - b. NO_x: 71.50 tons per year on a 12-month rolling sum basis after the Unit 85 Hydrogen Unit starts up. Until then, 65.00 tons per year, determined monthly on a rolling 12-month basis.
 - c. CO: 18.46 tons per year on a 12-month rolling sum basis.
 - d. Ammonia: 117.00 tons per year on a 12-month rolling sum basis.
6. FCCU Catalyst Regenerator Stack
- a. SO₂ emissions shall not exceed 6.01 lb per thousand barrels of gas oil feed, as determined on a rolling 12-month average basis (ARM 17.8.752, ARM 17.8.819).
 - b. SO₂ emissions shall not exceed 26.32 tons per year as determined monthly on a rolling 12-month sum basis (ARM 17.8.749).
 - c. SO₂ emissions from the FCCU shall not exceed 25 ppmvd at 0% O₂ based on a rolling 365-day average, as well as 50 ppmvd at 0% O₂ based on a rolling 7-day average. SO₂ emission data during startup, shutdown or malfunction of the FCCU or during periods of malfunction of a control system or pollutant reducing catalyst additive system will not be used in determining compliance with the 7-day SO₂ emission limit, provided that Phillips 66 implements good air pollution control practices to minimize SO₂ emissions. The 7-day SO₂ emission limit shall not apply during periods of hydrotreater outages provided that Phillips 66 is maintaining and operating the FCCU (including associated air pollution control equipment) in a manner consistent with good air pollution control practices for minimizing emissions in accordance with the EPA-approved Hydrotreater Outage Plan (Plan). In those instances where Phillips 66 chooses (as allowed by the Plan provisions) to exclude the Hydrotreater Outage period from the 7-day SO₂ emission limit, it must demonstrate compliance with the applicable requirements of the Plan in the post-outage report required pursuant to the Plan. Hydrotreater outage shall mean the period of time during which the operation of an FCCU is affected as a result of catalyst change-out operations or shutdowns required by American Society of Mechanical Engineers (ASME) pressure vessel requirements or state boiler codes, or as a result of malfunction that prevents the hydrotreater from effectively producing the quantity and quality of feed necessary to achieve established FCCU emission performance. For days in which the FCCU is not operating, no SO₂ value shall be used in the average, and those periods shall be skipped in determining the 7-day and 365-day averages (ARM 17.8.749).

- d. SO₂ emissions from FCCU shall not exceed 9.8 kilograms per Megagram (kg/Mg, or 20 lb/ton) coke burnoff on a 7-day rolling average basis, in accordance with 40 CFR 60.104(b)(2) and (c). As an alternative, Phillips 66 shall process in the FCCU fresh feed that has a total sulfur content no greater than 0.30 percent by weight on a 7-day rolling average basis, in accordance with 40 CFR 60.104(b)(3) and (c). This limit became effective on February 1, 2005 (ARM 17.8.749).
- e. CO emissions shall not exceed 150 ppmvd at 0% O₂ based on a rolling 365-day average basis, including periods of startup and shutdown (ARM 17.8.749, ARM 17.8.752, ARM 17.8.819).
- f. CO emissions shall not exceed 500 ppmvd at 0% O₂ based on a one-hour average emission limit. CO emissions during periods of startup, shutdown or malfunctions of the FCCU will not be used for determining compliance with this emission limit, provided that Phillips 66 implements good air pollution control practices to minimize CO emissions (ARM 17.8.749, ARM 17.8.752, ARM 17.8.819).
- g. CO emissions shall not exceed 133.80 tons per year on a rolling 12-month sum basis (ARM 17.8.749).
- h. NO_x emissions shall not exceed 49.2 ppmvd corrected to 0% O₂, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O₂, on a rolling 7-day average. NO_x emission data during startup, shutdown, or malfunction of the FCCU or during periods of malfunction of a control system or pollutant reducing catalyst additive system will not be used in determining compliance with the 7-day NO_x emission limit, provided that Phillips 66 implements good air pollution control practices to minimize NO_x emissions. The 7-day NO_x emission limit shall not apply during periods of hydrotreater outages provided that Phillips 66 is maintaining and operating the FCCU (including associated air pollution control equipment) in a manner consistent with good air pollution control practices for minimizing emissions in accordance with the EPA-approved Hydrotreater Outage Plan. In those instances where Phillips 66 chooses (as allowed per the Plan provisions) to exclude the Hydrotreater Outage period from the 7-day NO_x emission limit, it must demonstrate compliance with the applicable requirements of the Plan in the post-outage report required pursuant to the Plan. Hydrotreater outage shall mean the period of time during which the operation of an FCCU is affected as a result of catalyst change-out operations or shutdowns required by ASME pressure vessel requirements or state boiler codes, or as a result of malfunction that prevents the hydrotreater from effectively producing the quantity and quality of feed necessary to achieve established FCCU emission performance. For days in which the FCCU is not operating, no NO_x value shall be used in the average, and those periods shall be skipped in determining the 7-day and 365-day averages (ARM 17.8.749, ARM 17.8.752, ARM 17.8.819).

- i. NO_x emissions shall not exceed 72.09 tons per year on a rolling 12-month sum basis (ARM 17.8.749).
- j. Total filterable particulate emissions - The FCCU shall not exceed the limit of 1.0 lb/1000 lbs coke burned (ARM 17.8.749, ARM 17.8.752, ARM 17.8.819).
- k. PM₁₀ and PM_{2.5} emissions, including condensable emissions, from the FCCU shall not exceed 47.35 tons per year on a rolling 12-month sum basis (ARM 17.8.749).
- l. Opacity - not to exceed 30%, except for one 6-minute average in any 1 hour period (ARM 17.8.749).

7. Refinery Fuel Gas Heaters/Furnaces

- a. Phillips 66 shall not burn fuel oil in any of its heaters (ARM 17.8.749).
- b. Phillips 66 shall not burn in any refinery fuel gas combustion devices any fuel that contains H₂S in excess of 162 ppmv determined hourly on a 3 hour rolling average basis and 50 ppmv determined daily on a 365 successive calendar day rolling average basis (ARM 17.8.752, ARM 17.8.749).
- c. The PSA purge gas used as heater fuel in the No. 1 H₂ Plant Reformer Heater (H-9401), No. 2 H₂ Plant Reformer Heater (H-9701), and No. 3 H₂ Plant Heater shall be sulfur free (ARM 17.8.752).
- d. The No. 1 H₂ Unit Reformer Heater (H-9401) and No. 2 H₂ Unit Reformer Heater (H-9701) shall burn only natural gas, PSA off-gas, and/or cryo off-gas, which are inherently low sulfur fuels (ARM 17.8.749).
- e. The No. 3 H₂ Unit Reformer Heater (H-8501) shall burn only natural gas and PSA off-gas, which are inherently low sulfur fuels (ARM 17.8.749).
- f. The H-2, H-4, H-5, H-15, and H-19 heaters shall be made inoperable and/or removed from the site (ARM 17.8.749).
- g. Combined SO₂ Emissions shall not exceed: 614 lb/day, rolling 24-hour average; and 45.5 TPY, rolling 12-month average for the following fuel gas combustion units (ARM 17.8.749):
 - i. Emission Point 2, H-1;
 - ii. Emission Point 7, H-10 – No. 2 HDS;
 - iii. Emission Point 8, H-11 – No. 2 HDS Debutanizer Reboiler;
 - iv. Emission Point 9, H-12 – No. 2 HDS Main Frac. Reboiler;
 - v. Emission Point 10, H-13 – Catalytic Reforming
 - vi. Unit #2;

- vii. Emission Point 11, H-14 – Catalytic Reforming
 - viii. Unit #2;
 - ix. Emission Point 13, H-16 – Saturated Gas Stabilizer Reboiler and PB Merox Disulfide Offgas;
 - x. Emission Point 14, H-17;
 - xi. Emission Point 15, H-18;
 - xii. Emission Point 17, H-20;
 - xiii. Emission Point 18, H-21;
 - xiv. Emission Point 20, H-23 – Catalytic Reforming Unit #2;
 - xv. Emission Point 21, H-24;
 - xvi. Emission Point 6, H-3901 – Coker Heater;
 - xvii. Emission Point 28, H-8401 – Recycle Hydrogen Heater;
 - xviii. Emission Point 29, H-8402 – Fractionator Feed Heater.
- h. Opacity from each of the Refinery Fuel Gas Heaters/Furnaces constructed prior to 1968 shall not exceed 40% averaged over any 6 consecutive minutes (ARM 17.8.304).
- i. Opacity from each of the Refinery Fuel Gas Heaters/Furnaces constructed after 1968, including the No. 5 HDS Charge Heater (H-9501), No. 5 HDS Stabilizer Reboiler Heater (H-9502), No. 2 H₂ Plant Reformer Heater (H-9701), Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, No. 1 H₂ Plant Reformer Heater (H-9401), and No. 3 H₂ Plant Heater (H-8501) shall each not exceed 20% averaged over 6 consecutive minutes (ARM 17.8.304).
- j. Emissions from the Small Crude Unit Heater (H-1) (ARM 17.8.752), Large Crude Unit Heater (H-24) (ARM 17.8.752), and Vacuum Furnace (H-17) (ARM 17.8.749), shall not exhibit an opacity of 10% or greater averaged over 6 consecutive minutes.
- k. PM₁₀ emissions, including condensable emissions, from the Coker Furnace H-3901, No. 4 HDS Recycle Hydrogen Heater H-8401, No. 4 HDS Fractionator Feed Heater H-8402, No. 5 HDS Charge Heater H-9501, No. 5 HDS Stabilizer Heater H-9502, Catalytic Reforming Unit #2 H-13, Catalytic Reforming Unit #2 H-14, Saturated Gas Stabilizer Reboiler H-16, Catalytic Reforming Unit #2 H-23, Alkyl Heater H-21, FCCU Preheater H-18, and No. 3 H₂ Plant Reformer Heater H-8501 shall not exceed 0.0031 pounds per million british thermal units (lb/MMBtu) on a higher heating value (HHV) basis (ARM 17.8.749).
- l. PM_{2.5} emissions, including condensable emissions, from the Coker Furnace H-3901, No. 4 HDS Recycle Hydrogen Heater H-8401, No. 4 HDS Fractionator Feed Heater H-8402, No. 5 HDS Charge Heater H-9501, No. 5 HDS Stabilizer Heater H-9502, Catalytic Reforming Unit #2 H-13, Catalytic Reforming Unit #2 H-14, Saturated Gas Stabilizer Reboiler H-16, Catalytic Reforming Unit #2 H-23, Alkyl Heater H-21, FCCU Preheater H-18, and No. 3 H₂ Plant Reformer Heater H-8501 shall not exceed 0.0021 lb/MMBtu on a HHV basis

(ARM 17.8.749).

- m. NO_x emissions from the Coker Heater H-3901, No. 4 HDS Recycle Hydrogen Heater H-8401, No. 4 HDS Fractionator Feed Heater H-8402, and No. 1 H₂ Plant Reformer Heater H-9401, combined, shall not exceed 17.22 lb/hr and 75.44 TPY on a rolling, 12 month sum basis (ARM 17.8.749).
- n. Emissions from the Small Crude Unit Heater (H-1) shall not exceed:
 - i. NO_x: 0.030 lb/MMBtu on a HHV basis. The averaging period intended for this condition is an averaging period as would be utilized in an approved source test protocol accepted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.749).
- o. Emissions from the Large Crude Unit Heater (H-24) shall not exceed:
 - i. NO_x: 40 ppmvd at 0% O₂ on a 30-day rolling average basis, determined daily (ARM 17.8.749, ARM 17.8.752, ARM 17.8.340, and 40 CFR 60 Subpart Ja).
- p. Emissions from the Vacuum Furnace (H-17) shall not exceed:
 - i. NO_x: 30 ppmvd at 0% O₂ on a 30-day rolling average basis, determined daily (ARM 17.8.752).
- q. Emissions from the No. 1 H₂ Unit Reformer Heater (H-9401) shall not exceed:
 - i. NO_x: 0.042 lb/MMBtu on a HHV basis. The averaging period intended for this condition is an averaging period as would be utilized in an approved source test protocol accepted in accord with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.749).
 - ii. CO: 0.025 lb/MMBtu (ARM 17.8.752).
 - iii. PM₁₀ and PM_{2.5}: 0.0075 lb/MMBtu (ARM 17.8.752 and ARM 17.8.819).
- r. Emissions from the No. 5 HDS Charge Heater (H-9501) shall not exceed:
 - i. NO_x: 0.03 pounds per million British thermal units (lb/MMBtu) on a HHV basis (ARM 17.8.749, ARM 17.8.752).
 - ii. CO: 0.317 lb/MMBtu on a HHV basis when the heater is

- operating at 10.9 MMBtu/hr or less (ARM 17.8.749, ARM 17.8.752).
- iii. CO: 0.1585 lb/MMBtu on a HHV basis when the heater is operating at greater than 10.9 MMBtu/hr (ARM 17.8.749, ARM 17.8.752).
- s. Emissions from the No. 5 HDS Stabilizer Reboiler Heater (H-9502) shall not exceed:
 - i. NO_x: 0.03 lb/MMBtu on a HHV basis (ARM 17.8.749, ARM 17.8.752).
 - ii. CO: 0.1585 lb/MMBtu on a HHV basis when the heater is operating at 29.9 MMBtu/hr or less (ARM 17.8.749, ARM 17.8.752).
 - iii. CO: 0.091 lb/MMBtu when the heater is operating at greater than 29.9 MMBtu/hr (ARM 17.8.749, ARM 17.8.752).
- t. Emissions from the No. 3 H₂ Plant Reformer Heater H-8501 shall not exceed:
 - i. NO_x: 35 ppmvd, corrected to 0% O₂, determined daily on a 30-day rolling average basis (ARM 17.8.752, ARM 17.8.819). Compliance shall be monitored via NO_x CEMS installed and operated in conformance with 40 CFR 60 Subpart Ja (ARM 17.8.749).
 - ii. CO: 0.03 lb/MMBtu on a HHV, 1-hr average basis, as demonstrated via source testing under fuel mix and firing rate representative of normal operation (ARM 17.8.752, ARM 17.8.819, ARM 17.8.749).
- u. Emissions from the No. 2 H₂ Plant Reformer Heater (H-9701) shall not exceed:
 - i. NO_x: 0.03 lb/MMBtu (ARM 17.8.749, ARM 17.8.752 and ARM 17.8.819).
 - ii. CO: 0.025 lb/MMBtu (ARM 17.8.749, ARM 17.8.752).
 - iii. PM₁₀ and PM_{2.5}: 0.0075 lb/MMBtu (ARM 17.8.752 and ARM 17.8.819).
- v. NO_x emissions from the Coker Heater (H-3901) shall not exceed 0.04 lb/MMBtu on a HHV basis (ARM 17.8.749).
- w. NO_x emissions from the Recycle Hydrogen Heater (H-8401) shall not exceed 0.03 lb/MMBtu on a lower heating value (LHV) basis

(ARM 17.8.752).

- x. NO_x emissions from the Fractionator Feed Heater (H-8402) shall not exceed 0.03 lb/MMBtu on a lower heating value (LHV) basis (ARM 17.8.752).

8. Main Boilerhouse Stack

- a. SO₂ Emissions shall not exceed: 321.4 lbs/hr, rolling 24-hour average; 3.857 ton/day; 1,407.8 TPY (fuel oil and fuel gas combustion) (ARM 17.8.749).
- b. SO₂ Emissions shall not exceed: 300 TPY from fuel oil combustion, based on a rolling 365-day average as determined by the existing SO₂ Continuous Emissions Monitoring System (CEMS) or replacement SO₂ CEMS subsequently installed and certified (ARM 17.8.749).
- c. H₂S content of fuel gas burned shall not exceed 0.10 gr/dscf, rolling 3-hr average (ARM 17.8.749)
- d. H₂S content of fuel gas burned in boilers #B-5 and #B-6 shall not exceed 96 ppmv on a rolling 365-day average (ARM 17.8.749).
- e. Opacity - 40% averaged over any 6 consecutive minutes, except during times that the exhaust from only boilers #B-5 and #B-6 are being routed to the main boiler stack, the opacity limit is 20% (ARM 17.8.304).
- f. NO_x emissions from boilers #B-5 and #B-6 shall each, when fired on RFG, not exceed 0.03 lb/MMBtu based on a rolling 365-day average or 24.05 TPY based on a rolling 365-day average. Compliance with the limits shall be monitored with the NO_x and O₂ CEMS subsequently installed and certified (ARM 17.8.752).
- g. CO emissions from boilers #B-5 and #B-6 shall each not exceed 0.04 lb/MMBtu based on a rolling 365-day average when fired on RFG (ARM 17.8.752).
- h. VOC emissions from boilers #B-5 and #B-6 shall each not exceed 4.32 tons/rolling 12-calendar month total (ARM 17.8.752).

9. Sulfur Pits of Sulfur Recovery Plant

Phillips 66 shall capture and treat or incinerate emissions from its sulfur pits with the other emissions from its sulfur recovery plant. Emissions sent to the incinerator are measured as part of the total emissions exiting the Jupiter Main Stack No. 1 (ARM 17.8.749).

10. Total SO₂ emissions for refinery and sulfur recovery facilities

Total SO₂ emissions for refinery and sulfur recovery facilities shall not exceed the limit of 3,103 TPY. In addition, where applicable, all other federal emission limitations shall be met (ARM 17.8.749).

11. All access roads shall use either paving or chemical dust suppression as appropriate to limit excessive fugitive dust, with water as a back-up measure, to maintain compliance with ARM 17.8.308 and the 20% opacity limitation. Phillips 66 shall use reasonable precautions during construction, and earth-moving activities shall use reasonable precautions to limit excessive fugitive dust and to mitigate impacts to nearby residential and commercial places (ARM 17.8.749, ARM 17.8.308).

12. Emissions from the loading of gasoline and distillates at the loading rack shall be limited to the following:

- a. The total VOC emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 milligrams per liter (mg/L) of gasoline loaded (ARM 17.8.342; 40 CFR 63 Subpart R; and ARM 17.8.752).
- b. The total CO emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.752).
- c. The total NO_x emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 4.0 mg/L of gasoline loaded (ARM 17.8.752).
- d. Phillips 66 shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU:
 - i. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.749).
 - ii. Any particulate emissions in excess of 0.10 gr/dscf corrected to 12% CO₂ (ARM 17.8.749).

13. Refinery Main Plant Relief Flare Stack

- a. The Main Refinery Plant Flare shall not burn any fuel gas that contains H₂S in excess of 162 ppm determined hourly on a 3-hour rolling average basis. The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

14. Jupiter Flare

- a. The Jupiter Flare shall not burn any fuel gas that contains H₂S in excess of 162 ppm determined hourly on a 3-hour rolling average basis. The

combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from this limit (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

15. Phillips 66 shall limit CO emissions from the No. 3 Hydrogen Plant Off-gasing to 26.82 tons per year on a 12-month rolling sum basis (ARM 17.8.752, ARM 17.8.819, ARM 17.8.749).
16. The maximum conductivity of water in the New Cooling Tower installed as part of MAQP 2619-39, the Vacuum Unit Cooling Tower CWT5, as well as the Jupiter Cooling Tower CT-615 A/B/C, shall not exceed 3,130 microsiemens per centimeter ($\mu\text{S}/\text{cm}$) at 25 degrees Celcius (ARM 17.8.749).
17. Backup Coke Crusher and Associated Diesel Fired Engine (CG3810)
 - a. The Coke Crusher and the Backup Coke Crusher shall not be operated simultaneously (ARM 17.8.749).
 - b. The engine associated with CG3810 shall not exceed a horsepower rating of 300 hp and shall have an EPA certification of Tier 3 or higher (ARM 17.8.749).
 - c. Phillips 66 shall use only ultra-low-sulfur diesel fuel with a sulfur content less than or equal to 0.0015% in the engine associated with CG3810 (ARM 17.8.752).
18. Misc Diesel Engines
 - a. The Backup Firepump Engine capacity shall not exceed 665 hp and shall have an EPA certification of Tier 3 or higher (ARM 17.8.749).
 - b. The Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps shall not have a capacity exceeding 300 hp and shall have an EPA cerfication of Tier 3 or higher (ARM 17.8.749).
 - c. The Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps shall not exceed 1,000 hours of operation in any rolling 12-month period (ARM 17.8.749).
19. Vacuum Furnace (H-17) and Large Crude Unit Heater (H-24)
 - a. The total NO_x emissions from the Vacuum Furnace (H-17) and Large Crude Unit Heater (H-24) shall not exceed 29.8 tons per rolling 12-month period. (ARM 17.8.749)
 - b. The toal SO_2 emissions from the Vacuum Furnace (H-17) and Large Crude Unit Heater (H-24) shall not exceed 7.4 tons per rolling 12-month period (ARM 17.8.749).

D. Testing Requirements – NSPS, NESHAP, and MACT

1. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units.
2. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart J, Standards of Performance for Petroleum Refineries.
3. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007.
4. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart Ka, Standards of Performance for Storage Vessels for Petroleum Liquids. This shall apply to all petroleum liquid storage vessels for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984 (for requirements not overridden by 40 CFR 63 Subpart CC). These requirements shall be as specified in 40 CFR 60.110a through 60.115a.
5. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels. This shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984 (for requirements not overridden by 40 CFR 63 Subpart CC).
6. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After November 7, 2006.
7. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart GGGa – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006.
8. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.340, which reference 40 CFR 60 Subpart QQQ, Standards of Performance for Volatile Organic Compound Emissions from Petroleum Refinery Wastewater Systems (for requirements not overridden by 40 CFR 63 Subpart CC).

9. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63 Subpart R, NESHAPs for Gasoline Distribution Facilities (Bulk Gasoline Terminals and Pipeline Breakout Stations).
10. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63 Subpart CC, NESHAPs from Petroleum Refineries.
11. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63 Subpart UUU, NESHAPs for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units.
12. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63 Subpart DDDDD, NESHAPs for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.
13. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63 Subpart EEEE, NESHAPs for Organic Liquids Distribution (Non-Gasoline).
14. Phillips 66 shall meet, as applicable, the requirements of all testing and procedures of ARM 17.8.342, which references 40 CFR 63 Subpart WW, National Emissions Standards for Storage Vessels (Tanks) – Control Level 2.

E. Emission Testing and Monitoring

1. Phillips 66 shall monitor the FCCU Catalyst Regenerator for compliance with PM₁₀ and PM_{2.5} emissions limits (including condensables) in the following manner (ARM 17.8.749 and ARM 17.8.105):
 - a. By the startup of the FCCU following the planned refinery turnaround in which physical modifications of the FCCU as permitted in MAQP #2619-39 is accomplished, Phillips 66 shall have installed a sampling port as necessary for Method 201a and Method 202 testing.
 - b. Within 180 days of startup of the FCCU following the planned refinery turnaround in which physical modifications of the FCCU as permitted in MAQP #2619-39 is accomplished, Phillips 66 shall conduct a Method 201a and Method 202 test. Due to velocity of the stack, it may be found that a Method 201a cannot be completed within the requirements of the Method. Phillips 66 shall demonstrate a good faith effort to complete a successful test. Should velocity of the stack pose issues such that Method 201a cannot be accomplished within the requirements of the method, Phillips 66 shall prepare a detailed report detailing why the test cannot be completed, detailed explanation of the efforts made to complete a successful test, and provide the results of the Method 201a and 202 testing. A minimum of three full runs shall be completed regardless of Method 201a invalidations occurring.

- c. If a Method 201a cannot be successfully completed, Phillips 66 shall institute the FCCU Catalyst Regenerator Alternative Monitoring Compliance Demonstration Method for PM₁₀ and PM_{2.5} (including condensables), as follows:
- i. Within 30 days of determination of a need for the alternative compliance demonstration methodology, Phillips 66 shall propose a detailed filterable particulate size distribution study to DEQ. The submitted study shall include stack test protocol for Method 5 with a Method 202 back-half, and shall be conducted under catalyst conditions (catalyst type, catalyst emissions control additives, and catalyst refresh rates) which are representative of normal operations. Each operational scenario (each control technology operation scenario to be used) shall be tested separately.
 - ii. Within 90 days of determination of the need for an alternative compliance demonstration methodology, Phillips 66 shall conduct the Method 5 with Method 202 back-half test.
 - iii. Within 60 days of conducting the particle size distribution study, Phillips 66 shall report the results to DEQ. The results shall include the Method 5 and Method 202 results, the size distribution determinations, and the results of applying the size distribution determinations to the Method 5 plus Method 202 results, such that PM₁₀ (including condensables) and PM_{2.5} (including condensables) are reported.
 - iv. Compliance with the FCCU PM₁₀ and PM_{2.5} emission limits will be determined based on the reported results of applying the particle size distribution to the Method 5 results, plus the Method 202 results.
 - v. The particle size distribution study shall be repeated at least every 5 years, or as may be requested by Phillips 66 or DEQ.
 - vi. The Method 5 with Method 202 testing shall be conducted annually.
 - vii. Reporting of Method 5 with particle size distribution applied, plus Method 202, shall be reported with the source test reports.
- d. Annually thereafter the 180 day test, Phillips 66 shall conduct a Method 201a and Method 202 test, or, if such testing is previously demonstrated as not achievable within the requirements of the Method, in accord with the FCCU Catalyst Regenerator Alternative Monitoring Compliance Demonstration Method for PM₁₀ and PM_{2.5}. Phillips 66 may reattempt a Method 201a at any time.

2. Phillips 66 shall test boilers #B-5 and #B-6 for NO_x and CO compliance, both pollutants concurrently, on an every 5-year basis or according to another testing/monitoring schedule as may be approved by DEQ (ARM 17.8.105 and 17.8.749).
3. The bulk loading rack VCU shall be tested for compliance with the total organic compounds limitation every 5 years. Phillips 66 shall conduct the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).
4. Phillips 66 shall perform a Method 5 test on the FCCU catalyst regenerator stack at least once per calendar year to monitor compliance with the FCCU total filterable PM limitation. The annual tests shall be scheduled no closer than 6 months apart. (ARM 17.8.749).
5. Phillips 66 shall, concurrent with NO_x RATA testing, perform CO testing on the No. 3 H₂ Plant Heater H-8501 (ARM 17.8.749 and ARM 17.8.105).
6. Phillips 66 shall, within 180 days of completion of the Coker Unit changes, test the Coker Heater H-3901 for NO_x and CO concurrently to determine emissions on a lb/MMBtu basis. Thereafter, the Coker Heater shall be tested for NO_x and CO on an every calendar year schedule, with no two tests closer than 180 days apart (ARM 17.8.749 and ARM 17.8.105). Results of the tests shall be used as the emissions factors in determining mass emissions rates on a rolling 12-month basis (ARM 17.8.749). Phillips 66 may request a discontinuance of this testing requirement after three successive tests demonstrating compliance. Such request, and DEQ's determination, shall be made in writing. (ARM 17.8.749).
7. Phillips 66 shall test the H-8401, H-8402, and H-9401 to determine NO_x emissions on a lb/MMBtu basis once every 5 calendar years (ARM 17.8.749 and ARM 17.8.105). Results of the tests shall also be used as the emissions factors in determining mass emissions rates on a rolling 12-month sum basis (ARM 17.8.749).
8. Phillips 66 shall, within 180 days of startup of each SRU modified as permitted in MAQP #2619-39, test the associated Jupiter Main Stack for total filterable PM, PM₁₀ (including condensables), PM_{2.5} (including condensables), NO_x, and CO. For purposes of this testing, operations representative of near maximum capacity under operating scenario(s) producing the highest emissions of each pollutant, shall be required. Testing of Main Stack No. 1 shall occur with SRU I and SRU II operating at or near capacity. Testing of Main Stack No. 2 shall occur with SRU III operating at or near capacity. Such testing shall continue on an every 3 year basis. (ARM 17.8.749 and ARM 17.8.105).
9. Phillips 66 shall install and operate the following CEMS/continuous emission rate monitors (CERMs):

- a. Jupiter Main Stack No. 1 and Main Stack No. 2
 - i. SO₂ (SO₂ Board Ordered Stipulations as submitted in the State Implementation Plan (STIP), 40 CFR 60 Subpart Ja, ARM 17.8.749)
 - ii. O₂ (40 CFR 60 Subpart Ja)
 - iii. Volumetric flow rate (SO₂ STIP)
- b. FCCU Stack
 - i. SO₂ (40 CFR 60 Subpart J and ARM 17.8.749)
 - ii. Volumetric flow rate (SO₂ STIP)
 - iii. Opacity (40 CFR 60 Subpart J and ARM 17.8.749)
 - iv. CO (40 CFR 60 Subpart J and ARM 17.8.749)
 - v. NO_x (ARM 17.8.749)
 - vi. O₂ (ARM 17.8.749)
- c. Main Boiler Stack
 - i. SO₂ (SO₂ STIP; ARM 17.8.749)
 - ii. Volumetric flow rate (SO₂ STIP)
- d. Boilers #B-5 and #B-6
 - i. NO_x (40 CFR 60 Subpart Db)
 - ii. O₂ (ARM 17.8.749)
- e. No. 3 Hydrogen Plant Heater H-8501
 - i. NO_x for NSPS Ja and BACT limitations on a ppmvd basis. CEMS equipment, operation, calibration, performance evaluation, and emissions recording shall be accomplished utilizing the methodologies described and referenced in 40 CFR 60 Subpart Ja, and shall include O₂ monitoring, in accordance with the lb/MMBtu monitoring requirements of 40 CFR 60 Subpart Ja (ARM 17.8.749, ARM 17.8.340, 40 CFR 60 Subpart Ja).
- c. Vacuum Furnace H-17 and Large Crude Unit Heater H-24
 - i. NO_x for NSPS Ja and BACT limitations on a ppmvd basis. CEMS equipment, operation, calibration, performance evaluation, and emissions recording shall be accomplished utilizing the

methodologies described and referenced in 40 CFR 60 Subpart Ja, including 40 CFR 60 Subpart A and Appendix F and shall include O₂ monitoring (ARM 17.8.749, ARM 17.8.340, 40 CFR 60 Subpart Ja).

d. Refinery Main Plant Relief Flare:

- i. H₂S or TRS (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja)
- ii. Flow (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja)
- iii. Phillips 66 shall maintain records of the extent and duration of all periods in which the FGRS for the Refinery Main Plant Relief Flare is not operated. During such periods, Phillips 66 shall also measure or estimate (as appropriate) all SO₂ emissions which result from gases being directed to and combusted in the flare (ARM 17.8.749)
- iv. Flow rate metering from upset or malfunctioning process units that are directed to the flare shall use approved standards, methods, accounting procedures, and engineering data (ARM 17.8.749)
- v. Recordkeeping requirements (see Sections II.F.1-2) (ARM 17.8.749)

e. Jupiter Flare

- i. Flow (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja)
- ii. Jupiter Sulphur shall maintain records of the duration of all periods in which the rupture disk has been breached. During such periods, Jupiter Sulphur shall also measure or estimate (as appropriate) all SO₂ emissions which result from gases being directed to and combusted in the flare (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart Ja)
- iii. Flow rate metering from upset or malfunctioning process units that are directed to the flare shall use approved standards, methods, accounting procedures, and engineering data (ARM 17.8.749)
- iv. Recordkeeping requirements (see Sections II.F.1-2) (ARM 17.8.749)

10. Enforcement of requirements, where applicable, shall be determined by utilizing data taken from CEMS and other DEQ-approved sampling methods. However, opacity compliance may also be determined via EPA Reference Method 9 by a certified observer or monitor (ARM 17.8.749).

- a. The above does not relieve Phillips 66 from meeting any applicable requirements of 40 CFR 60 Appendices A and B, or other stack testing that may be required by DEQ.

- b. Other stack testing may include, but is not limited to, the following air pollutants: SO₂; NO_x; ammonia (NH₃); CO; PM, PM₁₀, PM_{2.5}, including condensable emissions; and VOC.
 - c. Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by DEQ.
 - d. SO₂ STIP 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).
11. Phillips 66 shall install, operate and maintain the applicable STIP/SO₂ Control Plan required CEMS on the Jupiter Main Stack 1 (SO₂, O₂ and volumetric flowrate), the FCCU Stack (volumetric flow rate), and the Main Boiler Stack (SO₂ and volumetric flow rate). Emission monitoring shall be subject to 40 CFR 60 Subpart J or Ja as applicable, Appendix B (Performance Specifications 1, 2, 3, 4/4A/4B, and 6) and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.749).
 12. Phillips 66 shall install, operate and maintain applicable CEMS as originally required by federal consent decree on the FCCU (SO₂, opacity, CO, NO_x, and O₂). Emission monitoring shall be subject to 40 CFR 60 §60.11, 60.13 and Part 60, Appendix A, Appendix B (Performance Specifications 2 and 3 and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.749). With respect to Appendix F, in lieu of the requirements of 40 CFR 60 Appendix F 5.1.1, 5.1.3 and 5.1.4, Phillips 66 shall conduct either a Relative Accuracy Audit or a Relative Accuracy Test Audit once every twelve (12) calendar quarters, provided that a Cylinder Gas Audit is conducted each calendar quarter.
 13. Phillips 66 shall install, operate and maintain the applicable NO_x and O₂ CEMS/CERMS on Boilers B-5 and B-6. Emission monitoring shall be subject to 40 CFR 60 Subpart Db; Appendix B (Performance Specifications 2, 3, 4/4A/4B, and 6). Emission monitoring shall be subject to 40 CFR 60, Appendix F or an alternate site-specific monitoring plan approved by DEQ, as appropriate (ARM 17.8.749).
 14. All CEMS are to be in operation at all times when the emission units are operating, except for quality assurance and control checks, breakdowns and repairs. In the event the primary CEMS is unable to meet minimum availability requirements, Phillips 66 shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated. The DEQ shall approve such contingency plans (ARM 17.8.749).
 15. Compliance testing and continuous monitor certification shall be as specified in 40 CFR 60, Appendices A and B. Test methods and procedures, where there is more than one option for any given pollutant, shall be worked out with DEQ prior to commencement of testing (ARM 17.8.749).

16. Phillips 66 shall conduct compliance testing and continuous monitor certification as specified in 40 CFR 60 Appendices A and B, within 180 days of initial start up of the affected facility (ARM 17.8.749).
17. Any stack testing requirements that may be required shall be conducted according to 40 CFR 60 Appendix A and ARM 17.8.105, Testing Requirements provisions (ARM 17.8.749).
18. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).
19. The DEQ may require further testing (ARM 17.8.105).

F. Recordkeeping and Reporting

1. Phillips 66 shall provide quarterly and/or semi-annual emission reports from all emission rate monitors. In addition to any specific NSPS or NESHAP reporting requirements, the periodic reports shall include the following (ARM 17.8.749):
 - a. Quarterly emission reporting for SO₂ from all point source locations shall consist of 24-hour calendar-day totals per calendar month;
 - b. Source or unit operating time during the reporting period;
 - c. Monitoring down time, which occurred during the reporting period;
 - d. A summary of excess emissions for each pollutant and averaging period identified in Section II.C; and
 - e. Reasons for any emissions in excess of those specifically allowed in Section II.C. with mitigative measures utilized and corrective actions taken to prevent a recurrence of the upset situation.

Phillips 66 shall submit the quarterly and/or semi-annual emission reports within 30 days of the end of each reporting period.

2. Phillips 66 shall keep DEQ apprised of the status of construction, dates of performance tests, and continuous compliance status for each emission point and pollutant. Specifically, the following report and recordkeeping shall be submitted in writing (ARM 17.8.749):
 - a. Notification of date of construction commencement, cessation of construction, restarts of construction, startups, initial emission tests, monitor certification tests, etc.
 - b. Submittal for review by DEQ of the emissions testing plan, results of initial compliance tests, continuous emission monitor certification tests, continuous emission monitoring and continuous emissions rate

monitoring quality assurance/quality control plans, and excess emissions report within the 180-day shakedown period.

- c. Copies of emissions reports, excess emissions, and all other such items mentioned in Section II.F.2.a and b above shall be submitted to both the Billings Regional Office and the Helena office of DEQ.
 - d. Monitoring data shall be maintained for a minimum of 5 years at the Phillips 66 Refinery and Jupiter sulfur recovery facilities.
 - e. All data and records that are required to be maintained must be made available upon request by representatives of the EPA.
3. Phillips 66 shall report to DEQ any time in which the sour water stripper stream from the refinery is diverted away from the sulfur recovery facility. Said excess emission reports shall include the period of diversion, estimate of lost raw materials (H_2S and NH_3), and resultant pollutant emissions, including circumstances explaining the diversion of this stream. Said excess emission reports shall discuss what corrective actions will be taken to prevent recurrences of the situation and what caused the upset. These reports shall address, at a minimum, the requirements of ARM 17.8.110 (ARM 17.8.749).
 4. Phillips 66 shall document, by month, the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No. 2 H_2 Plant PSA Offgas Vent. By the 30th day of each month Phillips 66 shall total the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No. 2 H_2 Plant PSA Offgas Vent during the previous month. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).
 5. Phillips 66 shall document, by month, the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No. 1 H_2 Plant PSA Offgas Vent. By the 30th day of each month Phillips 66 shall total the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No. 1 H_2 Plant PSA Offgas Vent during the previous month. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).
 6. Phillips 66 shall document, by month, the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No. 3 H_2 Plant PSA Offgas Vent. By the 30th day of each month Phillips 66 shall total the number of PSA offgas venting occurrences and the estimated CO emissions from each venting occurrence by the No. 3 H_2 Plant PSA Offgas Vent during the previous month, and the rolling 12-month total. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

7. Phillips 66 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 Appendix F (Quality Assurance and Quality Control) provisions. FCCU quarterly NO_x reporting shall be submitted in conjunction with the SO₂ STIP emissions and CEMS/CERMS reporting periods (ARM 17.8.749).
8. Phillips 66 shall document, annually, the number of operational hours of the Backup Coke Crusher. The information shall be submitted along with the annual emission inventory (ARM 17.8.749).
9. Phillips 66 shall document, annually, the maximum sulfur content of the diesel fuel used by the engine associated with CG3810 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 information shall be submitted along with the annual emission inventory (ARM 17.8.749).
10. Phillips 66 shall document, by the 25th day of each month, the monthly and rolling 12 month total of hours of operation of the Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps for the previous month. The information shall be submitted along with the annual emissions inventory (ARM 17.8.749).
11. Phillips 66 shall document, by the 25th day of each month, the monthly and rolling 12-month total NO_x emissions from the H-3901, H-8401, H-8402, and the H-9401. The information shall be submitted semiannually (i.e. in the Title V semi-annual monitoring reports) (ARM 17.8.749).
12. Phillips 66 shall document, by the 25th day of each month, the monthly and rolling 12-month total combined SO₂ emissions from the SRUs. The information shall be submitted semiannually (i.e. in the Title V semi-annual monitoring reports) (ARM 17.8.749).
13. Phillips 66 shall develop and document emissions factors for each SRU based on source testing of representative operational scenarios, such that each operational scenario has an associated emissions factor, except for ammonia, for which emissions may be estimated based on mass balance. By the 25th day of each month, the NO_x, SO₂, total filterable particulate, PM₁₀ (including condensibles), and PM_{2.5} (including condensibles) monthly and rolling 12 month totals shall be documented. The information shall be submitted semiannually (i.e. in the Title V semi-annual monitoring reports). Until emissions factors are developed based on source testing, emissions factors as presented in the application for MAQP #2619-39 shall be used (ARM 17.8.749).
14. Phillips 66 shall test a representative grab sample of cooling tower water for each cooling tower at least once per calendar quarter. Method 120.1 conductivity test procedures, as found for use under 40 CFR 136, or another

equivalent method as may be approved by DEQ, shall be utilized. Phillips 66 has been approved by DEQ to utilize EPA Method 2510B to determine conductivity. Phillips 66 shall maintain records of sample date and results. Such information shall be submitted semiannually (i.e. in the Title V semi-annual monitoring reports) (ARM 17.8.749).

G. Additional Reporting Requirements - NSPS, NESHAP, and MACT:

1. Phillips 66 shall keep records and furnish reports to DEQ as required by 40 CFR 60 Subpart Kb, for requirements not overridden by 40 CFR 63 Subpart CC. These reports shall include information described in 40 CFR 60.115b. If Phillips 66 chooses to comply with 40 CFR 63 Subpart WW to satisfy the requirements of 40 CFR 60.112b through 60.117b, Phillips 66 shall keep and furnish records according to 40 CFR 63.1065, 40 CFR 63.1066, and 40 CFR 60.110b(e)(5), as applicable (ARM 17.8.749).
2. Phillips 66 shall provide copies to DEQ, upon DEQ's request, of any records of tank testing results required by 40 CFR 60.113b and monitoring of operations required by 40 CFR 60.116b. Records shall be available according to the time period requirements as described in 40 CFR 60.115b and 40 CFR 60.116b. If Phillips 66 chooses to comply with 40 CFR 63 Subpart WW to satisfy the requirements of 40 CFR 60.112b through 60.117b, Phillips 66 shall comply with the requirements of 40 CFR 63.1063, 40 CFR 63.1065, and 40 CFR 63.1066, as applicable (ARM 17.8.749).
3. Phillips 66 shall keep records and furnish reports to DEQ as required by 40 CFR 60 Subpart QQQ, for requirements not overridden by 40 CFR 63 Subpart CC (ARM 17.8.749).
4. Phillips 66 shall provide copies to DEQ, upon DEQ's request, of any records of testing results, monitoring operations, recordkeeping and report results as specified under 40 CFR 60 Subpart QQQ, Sections 60.693-2, 60.696, 60.697, and 60.698, for requirements not overridden by 40 CFR 63 Subpart CC (ARM 17.8.749).
5. Phillips 66 shall supply DEQ's Permitting and Compliance Division with the reports as required by 40 CFR 61 Subpart FF, NESHAP for Benzene Waste Operations, for requirements not overridden by 40 CFR 63 Subpart CC (ARM 17.8.749).
6. Phillips 66 shall keep all records and furnish all reports to DEQ as required by 40 CFR 63 Subpart R, NESHAPs for Gasoline Distribution Facilities. These reports shall include information described in 40 CFR 63.424, 63.427, and 63.428 (ARM 17.8.749).
7. Phillips 66 shall keep all records and furnish all reports to DEQ as required by 40 CFR 63 Subpart CC, NESHAPs for Petroleum Refineries (MACT I). For storage vessels, Phillips 66 shall keep all records and furnish all reports to DEQ as required by 40 CFR 63 Subpart CC, NESHAPs for Petroleum Refineries

(MACT I), 40 CFR 60 Subpart Kb, or 40 CFR 63 Subpart WW, as applicable (ARM 17.8.749).

8. Phillips 66 shall keep all records and furnish all reports to DEQ as required by 40 CFR 63 Subpart UUU, NESHAPs for Petroleum Refineries: Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (MACT II) (ARM 17.8.749).
9. Phillips 66 shall keep all records and furnish all reports to DEQ as required by 40 CFR 63 Subpart EEEE, NESHAPs for Organic Liquids Distribution (Non-Gasoline) (ARM 17.8.749).

H. Operational Reporting Requirements

1. Phillips 66 shall supply DEQ with annual production information for all emission points, as required by DEQ in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the most recent emission inventory report and sources identified in this permit.

Production information shall be gathered on a calendar-year basis and submitted to DEQ by the date required in the emission inventory request. Information shall be in the units required by DEQ. This information is required for the annual emission inventory and to verify compliance with permit limitations. The information supplied shall include the following (ARM 17.8.505):

Point Name	Segment	Throughput Variable
Boiler #1	Fuel Gas	MMBtu
Boiler #2	Fuel Gas	MMBtu
Boiler #5	Fuel Gas	MMBtu
Boiler #6	Fuel Gas	MMBtu
Temporary Boiler	Natural Gas	MMBtu
H-1: Small Crude Heater	Fuel Gas	MMBtu
H-3: FCCU - Peabody Heater	Fuel Gas	MMBtu
H-10: HDS #2 Charge Heater	Fuel Gas	MMBtu
H-11: HDS #2 Debutanizer Reboiler	Fuel Gas	MMBtu
H-12: HDS #2 Main Frac Reboiler	Fuel Gas	MMBtu
H-13: Reformer #2 - #2 Reactor Preheater	Fuel Gas	MMBtu
H-14: Reformer #2 - #3 Reactor Preheater	Fuel Gas	MMBtu
H-16: Sat Gas Plant Heater	Fuel Gas	MMBtu
H-17: Vacuum Heater	Fuel Gas	MMBtu
H-18: FCC Pre-Heater	Fuel Gas	MMBtu
H-20: Butamer/Feed Prep Heater	Fuel Gas	MMBtu
H-21: Alky Heater	Fuel Gas	MMBtu
H-23: Reformer #2 - #1 Reactor Preheater	Fuel Gas	MMBtu

Point Name	Segment	Throughput Variable
H-24: Large Crude Heater	Fuel Gas	MMBtu
H-3901: Coker Heater	Fuel Gas	MMBtu
H-8401: HDS #4 Recycle Hydrogen Heater	Fuel Gas	MMBtu
H-8402: HDS #4 Fractionation Feed Heater	Fuel Gas	MMBtu
H-9401: Hydrogen #1 Heater	Natural Gas	MMBtu
	PSA Gas	MMBtu
	Cryo Gas	MMBtu
H-9501: HDS #5 Recycle Gas Heater	Fuel Gas	MMBtu
H-9502: HDS Stabilizer Reboiler Heater	Fuel Gas	MMBtu
H-9701: No. 2 H ₂ Plant Reformer Heater	Natural Gas	MMBtu
	PSA Gas	MMBtu
	Cryo Gas	MMBtu
Hydrogen Plant No. 3 Heater H-8501	Fuel Gas	MMBtu
	PSA Gas	MMBtu
	Cryo Gas	MMBtu
Refinery Flare	Flare Gas	MMBtu
Jupiter Flare	Flare Gas	MMBtu
SRU #1	lb emissions /yr (by pollutant)	1 (yr)
SRU #2	lb emissions/yr (by pollutant)	1 (yr)
SRU #3	lb emissions/yr (by pollutant)	1 (yr)
FCCU	barrels throughput	1000 barrels
New Cooling Tower 2022	Water Throughput	MM Gal
Cooling Tower Combination Unit	Water Throughput	MM Gal
Cooling Tower Condensate Unit	Water Throughput	MM Gal
Cooling Tower Vacuum Unit	Water Throughput	MM Gal
Cooling Tower CT 615 A/B/C	Water Throughput	MM Gal
Cooling Tower CT 120	Water Throughput	MM Gal
Cooling Tower CT 602	Water Throughput	MM Gal
Wastewater Collection and Treatment	Modeled Emissions	Pounds of emissions
Valves	# in Vapor Service	est. number in service (NumX)
	# in Light Liquid Service	est. number in service (NumX)
	# in Heavy Liquid Service	est. number in service (NumX)
	CVS Service	est. number in service (NumX)
Pumps	# in Light Liquid Service	est. number in service (NumX)
	# in Heavy Liquid Service	est. number in service (NumX)
Compressor Seals	# in gas service	est. number in service (NumX)
Flange/Connector	# in service	est. number in service (NumX)
Spills	Spills	Pounds of emissions
Lab/Sampling Connections	Lab/Sampling Connections	est. number in service (NumX)

Point Name	Segment	Throughput Variable
Tank #1	Tank #1	1000 barrels
Tank #2	Tank #2	1000 barrels
Tank #3	Tank #3	1000 barrels
Tank #5	Tank #5	1000 barrels
Tank #7	Tank #7	1000 barrels
Tank #8	Tank #8	1000 barrels
Tank #9	Tank #9	1000 barrels
Tank #10	Tank #10	1000 barrels
Tank #12	Tank #12	1000 barrels
Tank #13	Tank #13	1000 barrels
Tank #14	Tank #14	1000 barrels
Tank #16	Tank #16	1000 barrels
Tank #20	Tank #20	1000 barrels
Tank #21	Tank #21	1000 barrels
Tank #33	Tank #33	1000 barrels
Tank #41	Tank #41	1000 barrels
Tank #42	Tank #42	1000 barrels
Tank #45	Tank #45	1000 barrels
Tank #46	Tank #46	1000 barrels
Tank #47	Tank #47	1000 barrels
Tank #48	Tank #48	1000 barrels
Tank #49	Tank #49	1000 barrels
Tank #52	Tank #52	1000 barrels
Tank #53	Tank #53	1000 barrels
Tank #54	Tank #54	1000 barrels
Tank #55	Tank #55	1000 barrels
Tank #57	Tank #57	1000 barrels
Tank #72	Tank #72	1000 barrels
Tank #74	Tank #74	1000 barrels
Tank #75	Tank #75	1000 barrels
Tank #86	Tank #86	1000 barrels
Tank #87	Tank #87	1000 barrels
Tank #102	Tank #102	1000 barrels
Tank #110	Tank #110	1000 barrels
Tank #0851	Tank #0851	1000 barrels
Tank #1007	Tank #1007	1000 barrels
Tank #1008	Tank #1008	1000 barrels
Tank #1009	Tank #1009	1000 barrels
Tank #1102	Tank #1102	1000 barrels
Tank #1143	Tank #1143	1000 barrels
Tank #2909	Tank #2909	1000 barrels

Point Name	Segment	Throughput Variable
Coke Handling Equipment	Coke	Tons of Coke Processed
Railcar Clarified Oil Loading	Railcar Clarified Oil Loading	BBL of Oil Loaded
Diesel Engines	Diesel Engines	MMBtu
Gasoline Engines	Gasoline Engines	MMBtu

2. Phillips 66 shall notify DEQ of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to DEQ, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

I. Notification

Phillips 66 shall provide DEQ with written notification of the following dates within the specified time periods:

1. Pretest information forms must be completed and received by DEQ no later than 25 working days prior to any proposed test date, according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).
2. The DEQ must be notified of any proposed test date 10 working days before that date, according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).
3. For every time the Temporary Boiler is brought onsite, Phillips 66 shall provide written notification to DEQ of the initiation of operation within 15 days. The notification will include the year of construction, and natural gas firing rate (ARM 17.8.749).

SECTION III: General Conditions

- A. Inspection - The recipient shall allow DEQ's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.
- B. Waiver - The permit and all the terms, conditions, and matters stated herein shall be deemed accepted if the recipient fails to appeal as indicated below.
- C. Compliance with Statutes and Regulations - Nothing in this permit shall be construed as relieving the permittee of the responsibility for complying with any

applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq.* (ARM 17.8.756).

- D. Enforcement - Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement as specified in Section 75-2-401 *et seq.*, MCA.
- E. Appeals - Any person or persons jointly or severally adversely affected by DEQ's decision may request, within 15 days after DEQ renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay DEQ's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of DEQ's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, DEQ's decision on the application is final 16 days after DEQ's decision is made.
- F. Permit Inspection - As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by DEQ at the location of the source.
- G. Duration of Permit - Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762).
- H. Permit Fees - Pursuant to Section 75-2-220, MCA, failure to pay the annual operation fee by the permittee may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

Montana Air Quality Permit Analysis
Phillips 66 Company, Billings Refinery
Montana Air Quality Permit (MAQP) #2619-45

I. Introduction/Process Description

A. Source Description – Phillips 66 Company

The Phillips 66 Company, Billings Refinery (Phillips 66) is located at 401 South 23rd Street, Billings, Montana, in the NW¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. The refinery property is adjacent to the City of Billings and is next to Interstate 90 and the Yellowstone River. Residential properties exist on the west side of the refinery and the United States Postal Service has an office located on the south side of the property.

The refinery has the capability to process an annual average of approximately 72,500 barrels per day of crude oil and produces a wide range of petroleum products, including propane, gasoline, kerosene/jet fuel, diesel, and petroleum coke. All previously permitted equipment, limitations, conditions, and reporting requirements stated in MAQPs #1719, #2565, #2669, #2619, and #2619A were included in MAQP #2619-02.

Phillips 66 Pipeline, LLC: Transportation Operations

Phillips 66 Pipeline LLC is a subsidiary of Phillips 66 Company, under which transportation operations are managed. Phillips 66 Pipeline, LLC has loading rack operations adjacent to the refinery operations that are covered under this MAQP. The portions of the source under the management of the Phillips 66 Pipeline, LLC were provided a separate Title V Operating Permit for purposes of facilitating Responsible Official responsibilities in line with management structure. For PSD/NSR, Title V applicability, and MACT permit review purposes, the Transportation Operations and Refinery Operations are considered one source.

Source Description – Jupiter Sulphur, LLC

Jupiter Sulphur, LLC (Jupiter) operates a sulfur recovery operation, within the petroleum refinery area described above, at 2201 7th Avenue South, Billings, Montana. The facility is operated as a joint venture, of which Phillips 66 is a partner. The Jupiter facility consists of three sulfur recovery units. For PSD/NSR, Title V applicability, and MACT permit review purposes, the Jupiter Operations and Refinery Operations are considered one source.

B. Permit History

On October 29, 1982, Conoco Inc. (Conoco) received an air quality permit for an emergency flare stack to be equipped and operated with steam injection. This application was given **MAQP #1719**.

On June 2, 1989, Conoco received an air quality permit to convert an existing 5,000-barrel cone roof tank (#49) to an internal floating roof with double seals. This conversion was necessary in order to switch service from diesel to aviation gasoline storage. The application was given **MAQP #2565**.

On January 29, 1991, Conoco received an air quality permit to construct and operate two 2,000-barrel desalter wastewater break tanks equipped with external floating roofs and double-rim seals. The new tanks were to augment the refinery's ability to control fugitive Volatile Organic Compounds (VOC) emissions and enhance recovery of oily water from the existing wastewater treatment system. The application was given **MAQP #2669**.

On April 19, 1990, Conoco received an air quality permit to construct new equipment and modify existing equipment at the refinery and to construct a sulfur recovery facility, operated by Kerley Enterprises under the control of Conoco, as part of the overall Conoco project. The application was given **MAQP #2619**.

Conoco was permitted to construct a new 13,000-barrels-per-stream-day delayed petroleum coker unit, cryogenic gas plant, gasoline treating unit, and hydrogen system additions. Also, modifications to the existing crude and vacuum distillation units, hydrodesulfurization units, amine treating units and wastewater treatment system were permitted.

Conoco was also permitted to construct a sulfur recovery facility (SRU)/ATS to be operated by Kerley Enterprises. This facility is operated in conjunction with the new installations and modifications at the Conoco Refinery. This facility was permitted with the capability of utilizing 109.9 LT/D of equivalent sulfur obtained from the Conoco Refinery for the manufacture of elemental sulfur and sulfur-containing fertilizer solutions (i.e., ATS).

On December 4, 1991, Conoco was issued **MAQP #2619A** for the construction of a 1,000-barrel hydrocarbon storage tank (T-162). The new tank stores recovered hydrocarbon product from the contaminated groundwater aquifer beneath the Conoco Refinery. Over the years, surface discharges at the refinery contaminated the groundwater with oily hydrocarbon products. The purpose of this project was to recover hydrocarbon product (oil) from the groundwater aquifer beneath the refinery. The hydrocarbon product (oil) is pumped out of a cone of depression within the contaminated groundwater aquifer. Groundwater, less the recovered hydrocarbon product, is returned to the aquifer. The application addressed the increase in VOC emissions from the storage of recovered hydrocarbon product.

On March 5, 1993, Conoco was issued **MAQP #2619-02** for the construction and operation of a 5.0-MMscf-per-day hydrogen plant and to replace their existing American Petroleum Institute (API) separator system with a CPI separator system. This permit was an alteration to Conoco's existing MAQP #2619 and included all previously permitted equipment, limitations, conditions, and reporting requirements stated in MAQPs #1719, #2565, #2669, #2619, and #2619A.

The natural gas feedstock to the new hydrogen plant produces 99.9% pure hydrogen. This hydrogen and hydrogen from the existing catalytic reformers is routed to the refinery hydrotreaters to reduce fuel product sulfur content. The Hydrogen sulfide (H₂S) produced is routed to the Jupiter SRU/ATS, operated by Kerley Enterprises, which produces sulfur and fertilizer products.

The two new CPI separator tanks with carbon canister total VOC controls were constructed to comply with 40 Code of Federal Regulations (CFR) 60, Subpart QQQ, and 40 CFR 61, Subpart FF regulations. The CPI separators were vented to two carbon canisters in series. Each carbon canister was designed and operated to reduce VOC emissions by 95% or greater, with no detectable emissions. This CPI separator system replaced the existing API separator system.

As per a letter received by the Department of Environmental Quality (DEQ), on December 22, 1992, ownership of the Kerley Enterprises facility was transferred to Jupiter Sulphur, Inc. as of December 31, 1992.

On September 14, 1993, Conoco was issued **MAQP #2619-03** for the construction and operation of a gas oil hydrotreater and associated hydrogen plant at the Billings Refinery. The new hydrotreater desulfurizes a mixture of Fluid Catalytic Cracker Unit (FCCU) feed gas oils, which allows the FCCU to produce low-sulfur gasoline. This low-sulfur gasoline was required by January 1, 1995, to satisfy Environmental Protection Agency's (EPA) gasoline sulfur provisions of the Federal 1990 Clean Air Act Amendments. Hydrogen requirements are met by the installation of a hydrogen plant, and sulfur recovery capacity was provided by installing additional elemental liquid sulfur production facilities at the Jupiter Sulphur, Inc. plant adjacent to the refinery.

The Gas Oil Hydrodesulfurizer (GOHDS) was designed to meet the primary objective of removing sulfur from the FCCU feedstock. A combination of gas oils feed the Gas Oil Hydrotreater. The gas oils are mixed with hydrogen, heated, and passed over a catalyst bed where desulfurization occurs. The gas oil is then fractionated into several products, cooled, and sent to storage. A steam-methane reforming hydrogen plant produces makeup hydrogen for the unit. Any unconsumed hydrogen is amine treated for hydrogen H₂S removal and recycled.

The new project did not increase refinery capacity. The project did not constitute a major modification for purposes of the New Source Review - Prevention of Significant Deterioration (NSR-PSD) program since net emissions did not increase in significant amounts as defined by the Administrative Rules of Montana (ARM) 17.8.801(20)(a).

The additional fugitive VOC emissions from this project were calculated by totaling the fugitive sources on the process units. These sources included flanges, valves, relief valves, process drains, compressor seal degassing vents and accumulator vents and open-ended lines. The fugitive source tabulation was then used with actual refinery emission factors obtained from the Conoco Refinery in Ponca City, Oklahoma. Furthermore, it was intended that each non-control valve in VOC service would be repacked with graphite packing to Conoco standards before installation. All control valves for the GOHDS

project would be Enviro-Seal valves or equivalent. The Enviro-Seal valves have a performance specification that exceeds the Subpart GGG standards. The VOC emissions will be validated by 40 CFR 60, Subpart GGG, emission monitoring.

The Jupiter Sulphur, Inc. Recovery Facility consists of three primary units: the existing ATS Plant, the existing ATS Unit and the new Claus Sulfur and TGTU. The addition of the new units increased the total sulfur recovery capacity of the facility from 110 to 170 LT/D of sulfur.

The existing ATS plant consisted of a thermal Claus reaction-type boiler. The exit gas from this Claus boiler is incinerated in the ATS Unit. The SO₂ from the incinerator is absorbed and converted to ammonium bisulfite (ABS). The ABS is then used to absorb and react with H₂S to produce the ATS product. Up to 110 LT/D of sulfur can be processed by the ATS Plant to produce sulfur and ATS.

The ASD consists of an absorption column, which absorbs the sulfur as H₂S in the acid gas feed and reacts with NH₃ and water. When the new Claus Sulfur Unit was added, the Sulfur Recovery Facility was modified to incinerate any off gas from this unit in the TGTU and ATS Plant. This eliminates off-gas flow to, and emissions from, the flare. Up to 110 LT/D of sulfur can be processed by the ASD to produce ammonium sulfide solution.

The proposed Claus Sulfur Unit consisted of a thermal Claus reaction furnace, followed by a waste heat boiler and three catalytic Claus reaction beds. The Claus tail gas is then incinerated before entering the TGTU. In this new unit, SO₂ from the incinerator was absorbed and converted to ABS. This ABS is then transferred to the ATS Unit for conversion to ATS. Up to 110 LT/D of sulfur can be processed by the new Claus Sulfur Unit to produce sulfur and ABS. The ABS from the TGTU is dilute, containing a significant amount of water that was generated from the Claus reaction. To prevent making a dilute ATS from this "weak" ABS, a new ATS Reactor was added to the ATS Unit. This ATS Reactor combines "weak" ABS, additional ABS, and sulfur to make a full-strength ATS solution.

An important feature of the Jupiter Sulphur, Inc. facility is its capability to process Conoco Inc.'s sour gases at all times. A maximum of 170 LT/D of sulfur is recovered and each of the three units has a capacity of 110 LT/D. If any one of the three is out of service, then the other two can easily handle the load. While the process has 100% redundancy, any two of the three units must be running to handle the design load. The process uses high-efficiency gas filters, which employ a water-flushed coalescer cartridge to reduce particulate, as well as sulfur compounds.

On November 11, 1993, Conoco was issued **MAQP #2619-04** to construct and operate a new compressor station and associated equipment at the Billings Refinery. The C-23 compressor station project involved the recommissioning of an out-of-service compressor and associated equipment components having fugitive VOC emissions. The project also involved the installation of new equipment components having fugitive VOC emissions. The recommissioned compressor was originally installed in 1948. The

compressor underwent some minor refurbishing, but did not trigger "reconstruction" as defined in 40 CFR 60.15.

The purpose of the C-23 compressor station project was to improve the economics of the refinery's wet gas (gas streams containing recoverable liquid products) processing through increased yields and more efficient operation in the refinery's large and small Crude Topping Units (CTUs) and the Alkylation Unit. The project also improved safety in the operations of the two CTUs, Alkylation Unit, and Gas Recovery Plant (GRP). As a result of this project, the vapor pressure of the alkylate product (produced by the Alkylation Unit) was lowered.

On February 2, 1994, Conoco was issued **MAQP #2619-05** to construct and operate a butane defluorinator within the alkylation unit at the refinery. Installation of an alumina (Al_2O_3) bed defluorinator system was to remove residual hydrofluoric acid (HF) and organic fluorides from the butane stream produced by the Alkylation Unit. This reduced the fluorine level of the butane from ~ 500 parts per million by weight (ppmw) to ~ 1 ppmw, which allows the butane to be recycled back to the refinery's Butamer Unit for conversion into isobutane. Refer to the permit application for a more thorough description of the process and proposed changes.

The Alkylation Unit Butane Defluorinator Project resulted in: (1) changes in operation of the alkylate stabilization train of the Alkylation Unit to yield defluorinated butane instead of fluorinated and lower vapor pressure alkylate products; (2) changes in operation of the refinery's gasoline blending to restructure butane blending and lower the vapor pressure of the gasoline pool; (3) minimized butane sales; (4) minimized butane burning as refinery fuel gas; and (5) economized gasoline blending of butane.

On March 28, 1994, Conoco was issued **MAQP #2619-06** to construct and operate equipment to support a new PMA Unit at the refinery. The PMA project allowed Conoco to produce asphalt that meets the new federal specifications and to become a supplier of PMA for the region.

Installation of a 9.5-million British thermal units per hour (MMBtu/hr) natural gas-fired process heater to heat an oil heat transfer fluid supplies heat to bring the asphalt base to 400°F. This allows a polymer material to be mixed with it to produce PMA. A hot oil transfer pump was installed to circulate hot oil through the system. A heat exchanger (X-364) from the shutdown Propane De-asphalting (PDA) Unit was moved and installed to aid in the heating of the asphalt base. Two existing 5,000-bbl asphalt storage tanks were converted to PMA mixing and curing tanks. This required the installation of additional agitators, a polymer pellet loading (blower) system and conversion of the tank steamcoil heating system to hot oil heated by the new process heater. New asphalt transfer lines, a new asphalt transfer pump, and a new 5,000-bbl PMA storage tank (to replace the demolished T-50) were installed to keep the PMA separated from other asphalt products. This permit alteration also addressed the items submitted in a letter dated November 23, 1993, for supplemental information and a request for permit clarification for Conoco's MAQP #2619-03. This permit clarifies all these items, as appropriate, including the issues relating to the redesign of the SRU stack and the addition of heated air to the stack. Reference Section V, Air Quality Impacts.

On July 28, 1995, Conoco was issued **MAQP #2619-07** for the construction and operation of new equipment within the refinery's Alkylation (Alky) and Gas Recovery Plant/No.1 Amine Units. The project was referred to as the Alkylation Unit Depropanizer Project.

The existing Alkylation Unit was replaced with a new tower. The new depropanizer is located where the No.1 Bio-pond was located. Piping and valves were added, and existing equipment was located next to the new depropanizer. The old depropanizer was retained in place and may be used in the future in non- HF service.

The decommissioned PDA Unit evaporator tower (W-3) was converted to a water wash tower to remove entrained amine from the Alky PB (Propane/Butene) olefins upstream of the PB merox prewash. New piping, valves, and instrumentation were added around W-3.

The change in air emissions associated with this project was an increase in fugitive VOC emissions, as well as additional emission of fluorides due to the installation of the new depropanizer piping and valves.

The changes made by this project were not subject to NSR-PSD review since the sum of the emission rate increases were below PSD significant emission rates for applicable pollutants.

The drains installed or reused tie into parts of the refinery's wastewater sewer system that are already subject to Standards of Performance for New Stationary Sources (NSPS), Subpart QQQ (Wastewater Treatment System VOC Emissions in Petroleum Refineries) and National Emission Standards for Hazardous Air Pollutants (NESHAP), Subpart FF (Benzene Waste Operations). These drains were equipped with tight fitting caps and have hard pipe connections to meet the required control specifications.

On July 24, 1996, Conoco was issued **MAQP #2619-08** to change the daily SO₂ emissions limit of the 19 existing process heaters, as well as combining the 19 heaters, the Coker heater (H-3901), and the GOHDS heaters (H-8401 and H-8402) into one SO₂ point source within the Refinery. The project is referred to as the Existing Heater Optimization Project.

The 19 process heaters being discussed in this application are the process heaters (excluding H-3 and H-7) that were in operation prior to the construction of the Delayed Coker/Sulfur Reduction Project, which became fully operational in May of 1992. The 19 heaters are: H-1, H-2, H-4, H-5, H-10, H-11, H-12, H-13, H-14, H-15, H-16, H-17, H-18, H-19, H-20, H-21, H-22, H-23, and H-24. These 19 heaters are pooled together and regulated as one source referred to as the "19-Heater" source. Also included in this discussion are the Coker heater (H-3901) and the GOHDS heaters (H-8401 and H-8402).

The existing 19 heaters have a "bubbled" SO₂ permit emission limit of 30.0 tons per year (TPY) (164 lb/day) and a limitation of fuel gas H₂S content of 160 parts per million by

volume (ppmv) (0.1 grains per dry standard cubic foot (gr/dscf)). With both these limitations intact, all of these heaters cannot simultaneously operate at their maximum design firing rates. This can cause un-optimized operation of the Refinery during unfavorable climatical conditions or during peak heater demand periods.

To allow all 19 heaters to simultaneously operate at their maximum firing rates, the allowable short term SO₂ emission limit for the "bubbled" 19 heaters must be increased. The (19) Refinery Fuel Gas Heaters/Furnaces lb/day SO₂ emission limitation was based on MMBtu/hr from the emission inventory database (AFS), and higher fuel heat value (1,015 British thermal units per standard cubic foot (Btu/scf)) from the 1990 Base-Year Carbon Monoxide Emission Inventory. By using these parameters, the daily "bubble" SO₂ permit limit can be raised to 386 lb/day, as was indicated in the Preliminary Determination. Conoco requested the daily limit be increased to 612 lb/day, which is equivalent to the rate used in the Billings SO₂ State Implementation Plan (SIP) modeling (111.7 TPY). The annual "bubble" SO₂ limit of 30.0 TPY was maintained.

The DEQ received comments from Conoco, in which Conoco contends that the maximum heat input (MMBtu/hr) from the AFS does not accurately reflect the real maximum firing rates of the heaters. After further review of the files, DEQ established the total maximum firing rate for the (19) Refinery Fuel Gas Heaters/Furnaces to be 785.5 MMBtu/hr. This total maximum firing rate was identified by Conoco during the permit review of the Coker permit (MAQP #2619). The maximum heat input of 785.5 MMBtu/hr and the fuel heat of 958 Btu/scf are used to calculate a new daily "bubble" SO₂ permit limit of 529.17 lb/day.

The change in air emissions of other criteria pollutants (carbon monoxide (CO), nitrogen oxide (NO_x), particulate matter (PM), and VOC) associated with this project are zero, since the Potentials to Emit (PTE) were not changed. With the current 164-lb/day SO₂ limit, simultaneous maximum firing of these heaters can be accomplished if the fuel gas H₂S content stays below 49.75 ppmv. Conoco's amine systems produce fuel gas averaging (on an annual basis) of about 25 ppmv H₂S content or less (see 1993 and 1994 Refinery EIS's). Since the emissions of CO, NO_x, and VOC produced are not a function of H₂S content, and Conoco's current amine system can generate appropriate fuel gas to stay at or below the 164 lb/day SO₂ limit, the maximum potentials of these pollutants are obtainable and were not affected by this project. The PM limits for these heaters are 80 times higher than the amount generated by fuel gas combustion devices (see ARM 17.8.340); therefore, the PM emissions potential was not affected as well.

Even though Conoco's past annual average fuel gas H₂S content was below 37.8 ppmv, there was still potential to run into operational limitations in peak fuel gas demand periods. The amine systems may not be able to keep the fuel gas H₂S under 49.75 ppmv, rendering the refinery to operate at un-optimized rates. This was the reason for the request to raise the daily SO₂ emissions limit for the "19-Heater" source. Since the proposed change to the heaters' SO₂ emissions limit does not reflect an annual increase in PTE, the project is not subject to PSD permitting review (threshold for SO₂ is 40 TPY).

In light of the SO₂ problem in the Billings-Laurel air shed, any change resulting in an increase of SO₂ emissions must have its impact determined to see if any National Ambient Air Quality Standards (NAAQS) will be violated as a result of the project. SO₂ modeling was completed by DEQ to develop a revised SO₂ SIP for the Billings-Laurel area (see the Billings/Laurel SO₂ SIP Compliance Demonstration Report dated November 15, 1994). The "19-Heater source" was modeled using an SO₂ emission rate equivalent to 111.7 TPY to determine its SO₂ impact on the Billings-Laurel air shed. The results of this modeling showed there were no exceedances of the SO₂ NAAQS or the Montana standards resulting from its operation. Therefore, an increase in the permit limit from 164 lb/day to 612 lb/day of SO₂ did not result in any violations of SO₂ NAAQS or Montana standards; however, the daily emission limit set based on the NSPS limit of 0.1 grains per dry standard cubic foot (gr/dscf) (160 ppmv H₂S) is more restrictive than the SIP limit. The daily emission limit, based on NSPS, is 529.17 lb/day for the existing 19 heaters/furnaces.

With the change of a daily SO₂ permit limit for the "19-Heater" source, Conoco also requested that the "19-Heater" source, the Coker heater (H-3901), and the GOHDS heaters (H-8401 and H-8402) be combined into one permitted source called the "Fuel-Gas-Heaters" source. Using the existing daily SO₂ permit limits for the Coker heater and GOHDS heaters, an overall SO₂ emissions limit "bubble" of 614 lb/day would apply to the "22-Fuel-Gas-Heaters" source. The annual limit for the "22-Fuel-Gas-Heaters" source has not changed and is 45.50 TPY (30.00 + 9.60 + 2.90 + 3.00).

On April 19, 1997, Conoco was issued **MAQP #2619-09** to "bubble" or combine the allowable hourly and annual NO_x emission limits for the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heaters. The NO_x emission limits for these heaters were established on a pounds-per-million-Btu basis, and will be maintained.

By "bubbling" or combining the allowable hourly and annual NO_x emission limits for the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heaters allows Conoco more operational flexibility with regard to heater firing rates and heater optimization. The Coker heater still has an hourly NO_x emission limit to prevent any significant impacts. This permit alteration does not allow an increase in the annual NO_x emissions. MAQP #2619-09 replaced MAQP #2619-08.

On July 30, 1997, **MAQP #2619-10** was issued to Conoco in order to comply with 40 CFR 63, Subpart R, National Emission Standards for Gasoline Distribution Facilities. Conoco installed a gasoline vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAPs) resulting from the loading of gasoline. The vapor combustion unit (VCU) was added to the bulk gasoline and distillate loading rack. The gasoline vapors were collected from the trucks during loading, then routed to an enclosed flare, where combustion occurs. The project results in overall reductions in the amount of actual emissions of VOCs (94.8 TPY), with a slight increase in CO (2.1 TPY) and NO_x (0.8 TPY) emissions. The actual reduction in potential emissions of VOCs is 899.5 TPY, while CO increases to 19.7 TPY and NO_x increases to 7.9 TPY emissions.

In addition, Conoco requested an administrative change be made to Section II.F.5, which brought the permit requirements in alignment with the monitoring requirements specified by 40 CFR 60, Subpart QQQ, and 40 CFR 61, Subpart FF.

Because Conoco's Bulk gasoline and distillate loading tank VCU is defined as an incinerator under Montana Code Annotated (MCA) 75-2-215, a determination that the emissions from the VCU constitutes a negligible risk to public health is required prior to the issuance of a permit to the facility. Conoco and DEQ identified the following HAPs from the flare, which were used in the health risk assessment. These constituents are typical components of gasoline.

1. Benzene
2. Ethyl Benzene
3. Hexane
4. Methyl Tert Butyl Ether
5. Toluene
6. Xylenes

The reference concentrations for Ethyl Benzene, Hexane, and Methyl Tert Butyl Ether were obtained from EPA's IRIS database. The risk information for the remaining HAPs is contained in the January 1992 CAPCOA Risk Assessment Guidelines. The model performed by Conoco for the HAPs identified above, demonstrate compliance with the negligible risk requirement. MAQP #2619-10 replaced MAQP #2619-09.

On December 10, 1997, Conoco requested a modification to allow the continuous incineration of a PB Merox Unit off-gas stream in the firebox of Heater #16. MAQP #2619-10 required the production of SO₂ from the sulfur containing compounds in the PB Merox Unit off-gas stream to be calculated and counted against the current SO₂ limitations applicable to the (22) Refinery Fuel Gas Heaters/Furnaces group. During a review of process piping and instrumentation diagrams, Conoco identified a PB Merox Unit off-gas stream incinerated in the firebox of Heater #16. A subsequent analysis of this off-gas stream revealed the presence of sulfur-containing compounds in low concentrations. The bulk of this low-pressure off-gas stream is nitrogen with some oxygen, hydrocarbons, and sulfur-containing compounds (disulfides, mercaptans). SO₂ produced from the continuous incineration of this stream has been calculated at approximately 1 TPY. This off-gas stream is piped from the top of the disulfide separator through a small knock-out drum and directly into the firebox of Heater #16.

Conoco proposed to sample the PB Merox Unit disulfide separator gas stream on a monthly basis to determine the total sulfur (ppmw) present. This analysis, combined with the off-gas stream flow rate, is used to calculate the production of SO₂. After a year of sampling time and with the approval of DEQ, Conoco may propose to reduce the sampling frequency of the PB Merox disulfide separator off-gas stream to once per quarter if the variability in the sulfur content is small (250 ppmw).

In addition, to be consistent with the wording as specified by 40 CFR 63, Subpart R, DEQ replaced all references to "tank trucks" with "cargo tank" and all references to "truck loading rack" with "loading rack". Also, the first sentence in Section II.F.5 was

deleted from the permit. Conoco had requested an administrative change be made to Section II.F.5, during the permitting action of #2619-10, which would bring the permit requirements in alignment with the monitoring requirements specified by 40 CFR 60, Subpart QQQ, and 40 CFR 61, Subpart FF. The DEQ approved the request and the correction was made, but the first sentence was inadvertently left in the permit. **MAQP #2619-11** replaced MAQP #2619-10.

On June 6, 2000, DEQ issued **MAQP #2619-12** for replacement of the B-101 thermal reactor at the Jupiter Sulphur facility. The existing B-101 thermal reactor had come to the end of its useful life and had to be replaced. The replacement B-101 thermal reactor was physically located approximately 50 feet to the north of the existing thermal reactor, due to the excessive complications that would be encountered to dismantle the old equipment and construct the new equipment in the same space. Once the piping was rerouted to the new equipment the old equipment was incapable of use and will be demolished. Given this construction scenario, DEQ determined that a permit condition limiting the operation to only one thermal reactor at a time was necessary. There was no increase in emissions due to this action. MAQP #2619-12 replaced MAQP #2619-11.

Conoco submitted comments on the Preliminary Determination (PD) of MAQP #2619-12. The following is the result of these comments:

In previously issued permits, Section II.A.4 listed storage tanks #4510 and #4511 as having external floating roofs with primary seal, which were liquid mounted stainless steel shoes and secondary seal equipped with a Teflon curtain or equivalent. Conoco stated that these two tanks were actually equipped with internal floating roofs with double-rim seals or a liquid-mounted seal system for VOC loss control.

Section II.A.7.g.ii always listed the CPI separators as primary separators, when in fact they are secondary.

The DEQ accepted the comments and made the changes, accordingly, in DEQ decision version of the permit.

On March 1, 2001, DEQ issued **MAQP #2619-13** for the installation and operation of 19 diesel-powered, temporary generators. These generators are necessary because of the high cost of electricity and supplement 18 MW of the refinery's electrical load, and 1 MW of Jupiter's electrical load. The generators are located south of the coke loading facility along with two new aboveground 20,000-gallon diesel storage tanks. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for Conoco to acquire a permanent, more economical supply of power.

Because these generators are only to be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of these generators is minor. In addition, the installation of these generators qualified as a "temporary source" under the PSD permitting program because the permit limited the operation of these generators to a time period of less than 2 years. Therefore, Conoco

was not required to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators were considered temporary, DEQ required compliance with Best Available Control Technology (BACT) and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 was ensured. In addition, Conoco is responsible for complying with all applicable ambient air quality standards. MAQP #2619-13 replaced MAQP #2619-12.

On April 13, 2001, DEQ issued **MAQP #2619-14** for the 1982 Saturate Gas Plant Project, submitted by Conoco as a retroactive permit application. During an independent compliance awareness review that was performed in 2000, Conoco discovered that the Saturate Gas Plant should have gone through the permitting process prior to it being constructed. At the time of construction, the project likely would have required a PSD permit. However, the current PTE for the project facility is well below the PSD VOC significance threshold. In addition, the Saturate Gas Plant currently participates in a federally-required leak detection and repair (LDAR) program, which would meet any BACT requirements, if PSD applied. The DEQ agreed that a permitting action in the form of a preconstruction permit application for the Saturate Gas Plant Project was necessary and sufficient to address the discrepancy. MAQP #2619-14 replaced MAQP #2619-13.

On June 29, 2002, DEQ issued **MAQP #2619-15** to clarify language regarding the Appendix F Quality Assurance requirements for the fuel gas H₂S measurement system and to include certain limits and standards associated with the Consent Decree lodged on December 20, 2001, respectively. In addition, DEQ modified the permit to eliminate references to the now repealed odor rule (ARM 17.8.315), to correct the reference on conditions improperly referencing the incinerator rule (ARM 17.8.316), and to eliminate the limits on the main boiler that were less stringent than the current limit established by the Consent Decree. MAQP #2619-15 replaced MAQP #2619-14.

The DEQ received a request from Conoco on August 27, 2002, for the alteration of air quality MAQP #2619-15 to incorporate the Low Sulfur Gasoline (LSG) Project into the refinery's equipment and operations. The LSG Project was being proposed to assist in complying with EPA's Tier 2 regulations. The project included the installation of a new storage vessel and minor modifications to the No.2 hydrosulfurization (HDS) unit, GOHDS unit, and hydrogen (H₂) unit in order to accommodate hydrotreating additional gasoline and gas oil streams that were currently not hydrotreated prior to being blended or processed in the FCCU. The new storage vessel was designed to store offspec gasoline during occasions when the GOHDS unit was offline.

In addition, on August 28, 2002, Conoco requested to eliminate the footnote contained in Section II.B.1.b of MAQP #2619-15 stating, "Emissions [of the SRU Flare] occur only during times that the ATS unit is not operating." Further, Conoco requested to change the SO₂ emission limitations of 25 pounds per hour (lbs/hr) for each of the SRU Flare and SRU/ATS Main Stack to a 25-lbs/hr limit on the combination of the SRU Flare and SRU/ATS Main Stack. Following discussion between Conoco and DEQ regarding comments received within DEQ and from EPA, Conoco requested an extension to delay issuance of DEQ Decision to December 9, 2002. Following additional discussion, Conoco and DEQ agreed to leave the footnote in the permit for

the issuance of **MAQP #2619-16** and to revisit the issue at another time. MAQP #2619-16 replaced MAQP #2619-15.

A letter from ConocoPhillips dated December 9, 2002, and received by DEQ on December 10, 2002, notified DEQ that Conoco had changed its name to ConocoPhillips. In a letter dated February 3, 2003, ConocoPhillips also requested the removal of the conditions regarding the temporary power generators because the permit terms for the temporary generators were “not to exceed 2 years” and the generators had been removed from the facility. The permit action changed the name on this permit from Conoco to ConocoPhillips and removed permit terms regarding temporary generators. **MAQP #2619-17** was also updated to reflect current permit language and rule references used by DEQ. MAQP #2619-17 replaced MAQP #2619-16.

On December 11, 2003, DEQ received a MAQP Application from ConocoPhillips to modify MAQP #2619-17 to replace the existing 143.8- MMBtu/hr boilers, B-5 and B-6, with new 183-MMBtu/hr boilers equipped with low NO_x burners (LNB) and flue gas recirculation (FGR) commonly referred to as ultra-low NO_x burners (ULNB), new B-5 and new B-6 (previously referred to as B-7 and B-8), to meet the NO_x emission reduction requirements stipulated in the EPA Consent Decree. On December 23, 2003, DEQ deemed the application complete. This permitting action contained NO_x emissions that exceed PSD significance levels. The replacement of the boilers resulted in an actual NO_x reduction of approximately 89 tons per year. However, the EPA Consent Decree stipulated that reductions were not creditable for PSD purposes. MAQP #2619 was also updated to reflect current permit language and rule references used by DEQ. **MAQP #2619-18** replaced MAQP #2619-17.

On February 3, 2004, DEQ received a MAQP Application from ConocoPhillips to modify MAQP #2619-18 to add a new HDS Unit (No.5), a new sour water stripper (No.3 Sour Water Stripper (SWS)), and a new H₂ Unit. On March 1, 2004, DEQ deemed the application complete upon submittal of additional information. The addition of these new units added three new heaters, 41, 42, and 43, each equipped with low LNB FGR commonly referred to as ULNB. Additionally, ConocoPhillips proposed to retrofit existing external floating roof tank T-110 with a cover to allow nitrogen blanketing of the tank, to install a new storage vessel (No.5 HDS Feed storage tank) under emission point 24 above, to store feed and off-specification material for the No.5 HDS Unit, and to provide the No.1 H₂ Unit with the flexibility to burn refinery fuel gas (RFG). The new equipment was added to meet the new EPA-required highway Ultra Low Sulfur Diesel (ULSD) fuel sulfur standard of 100% of highway diesel that meets the 15 parts per million (ppm) highway diesel fuel maximum sulfur specification by June 1, 2006. By meeting the June 1, 2006, deadline, ConocoPhillips may claim a 2-year extension for the phase in of the requirements of the Tier Two Gasoline/Sulfur Rulemaking. This permitting action resulted in NO_x and VOC emissions that exceed PSD significance levels. Other changes were also contained in this permit. Previously in permit condition II.A.1 it was stated that the emergency flare tip must be based at 148-foot elevation. After a physical survey of the emergency flare it was determined that the actual height of the flare tip is 141.5-foot elevation. After verifying that the impacts of the height discrepancy were negligible, DEQ changed permit condition II.A.1 from 148-feet of elevation to 142-feet plus or minus 2 feet of elevation and changed the

reference from ARM 17.8.752 to ARM 17.8.749. **MAQP #2619-19** was updated to reflect current permit language and rule references used by DEQ. MAQP #2619-19 replaced MAQP #2619-18.

On June 15, 2004, DEQ received an Administrative Amendment request from ConocoPhillips to modify MAQP #2619-19 to correct the averaging time for equipment subject to the 0.073 gr/dscf H₂S content of fuel gas burned limit. The averaging time was corrected from a rolling 3-hour time period to a rolling 12-month time period. The heaters subject to the 0.073 gr/dscf limit per rolling 12-month time period are subject to the Standards of Performance for NSPS, Subpart J limit of 0.10 gr/dscf per rolling 3-hour time period. **MAQP #2619-20** replaced MAQP #2619-19.

On March 15, 2005, DEQ received a complete MAQP Application from ConocoPhillips to modify MAQP #2619-20 to update the HDS Unit (No.5), sour water stripper (No.3 SWS), and H₂ Unit added in ULSD MAQP Modification #2619-19. Due to the final project design and vendor specifications, and further review of the EPA compiled emission factor data, the facility's emission generating activities, and MAQP #2619-19, ConocoPhillips proposed the following changes:

1. Deaerator Vent (44) at the No.2 H₂ Unit is to be deleted.
2. No. 2 H₂ Unit PSA Offgas Vent (45) is to be added.
3. CO emission factors for the three new heaters to be changed from AP-42 Section 1.4 (October 1996) to vendor guaranteed emission factors.
4. Particulate matter with an aerodynamic diameter of 10 microns or less (PM₁₀) exhaust emission factors for the combustion of PSA vent gas in the No.1 H₂ Heater and the No.2 H₂ Reformer Heater to be changed from AFSCF, EPA 450/4-90-003 p.23 to AP-42, Section 1.4 (July 1998).
5. The dimensions, secondary rim seal, and specific deck fittings data for the No.5 HDS Feed Tank to be updated. The tank is proposed to store material with a maximum true vapor pressure of 11.1 pounds per square inch at atmosphere (psia).
6. Specific deck fittings for existing Tank-110 to be revised. The tank is proposed to store material with a maximum true vapor pressure of 11.1 psia.
7. The existing No.1 H₂ Unit PSA Offgas Vent (46) to be added to the permit. This unit is not affected by the ULSD project, but is included with this submittal as a reconciliation issue.
8. The NO_x emissions limitations cited for each of the three new ULSD Project heaters are requested to be clarified as "per rolling 12-month time period."

9. The CO emissions limitations cited for each of the three new ULSD Project heaters be replaced and cited with the appropriate updated values and associated averaging periods.
10. The nomenclature for Boilers B-7 and B-8 be changed to new B-5 and new B-6 respectively.
11. In accordance with Paragraph 54 of the Consent Decree the FCCU became subject to the SO₂ portions of Standards of Performance for New Stationary Sources (NSPS), Subpart J on February 1, 2005.
12. 40 CFR 63 Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters) has been finalized. The regulatory applicability analysis has been updated for the three new heaters.

MAQP #2619-21 replaced MAQP #2619-20.

On January 15, 2007, DEQ received a complete application which included the request to incorporate the following permit conditions, which were requested in separate letters:

- Refinery Main Plant Relief Flare – to clarify that the flare is subject to NSPS 40 CFR 60, Subparts A and J (as requested September 28, 2004)
- FCCU – to clarify that the FCCU is subject to CO and SO₂ portions of Subpart J (requested September 26, 2003, and February 8, 2005, respectively, and partly addressed in MAQP #2619-21)
- FCCU – to clarify that the FCCU was subject to an SO₂ emission limit of 25 parts per million, on a volume, dry basis (ppmvd), corrected to 0% oxygen (O₂), on a rolling 365-day basis, and subject to an SO₂ emission limit of 50 ppmvd, corrected to 0% O₂, on a rolling 7-day basis, and clarify the 7-day SO₂ 50 ppmvd emission limit established for the FCCU shall not apply during periods of hydrotreater outages (requested February 1, 2006)
- Temporary Boiler Installation – to allow the installation and operation, for up to 8 weeks per year, of a temporary natural gas-fired boiler not to exceed 51 MMBtu/hr, as requested January 4, 2007

The permit was also updated to reflect the current style that DEQ issues permits.

MAQP #2619-22 replaced MAQP #2619-21.

The DEQ received two requests from ConocoPhillips for modifications to the permit in conformance with requirements contained in their Consent Decree (Civil Action #H-01-4430):

- 5/31/07 – request to clarify that the Jupiter Sulfur Plant Flare (Jupiter Flare) is

subject to 40 CFR 60, Subparts A and J; and

- 8/29/07 – request to clarify that the FCCU is subject to a PM emission limit of 1 lb per 1,000 lb of coke burned, and that it is an affected facility subject to 40 CFR 60, Subparts A and J, including the 30% opacity limitation. The requirement to maintain less than 20% opacity was then removed, since the FCCU became subject to the 30% Subpart J opacity limit which supersedes the ARM 17.8.304 opacity limit.

The DEQ amended the permit, as requested. In addition, the references to 40 CFR 63, Subpart DDDDD were changed to reflect that this regulation has become “state-only” since, although the federal rule was vacated on July 30, 2007, this MACT was incorporated by reference in ARM 17.8.342. Lastly, reference to Tank T-4524 was corrected to T-4523 (wastewater surge tank) and regulatory applicability changed from 40 CFR 60, Subpart Kb to Subpart QQQ, and the LSG tank identification was corrected to T-2909. **MAQP #2619-23** replaced MAQP #2619-22.

On August 21, 2008, DEQ received a complete NSR-PSD permit application from ConocoPhillips. ConocoPhillips is proposing to replace the existing Small and Large Crude Units and the existing Vacuum Unit with a new, more efficient Crude and Vacuum Unit. This project is referred to as the New Crude and Vacuum Unit (NCVU) project. The NCVU project will enable ConocoPhillips’ Billings refinery to process both conventional crude oils and SynBit/oil sands crude oils and increase crude distillation capacity about 25%. The NCVU project will require modifications and optimization of the following existing process units: No. 2 HDS Unit, Saturate Gas Plant, No. 2 and No. 3 Amine Units, No. 5 HDS Unit, Coker Unit, No. 1 and 2 H₂ Plants, Hydrogen Purification Unit (HPU), Raw Water Demineralizer System, Jupiter SRU/ATS Plant, and the FCCU. The primary objectives of the NCVU Project are to improve crude fractionation and energy efficiency of the refinery, and to increase crude processing capacity and crude feed flexibility to reduce feed costs. As a result of the NCVU Project, the Jupiter Plant feed rate capacity will need to be increased to approximately 235 LTD of sulfur. With the submittal of this complete application, the minor source baseline dates for SO₂, PM, and PM₁₀ have now been triggered in the Billings area as of August 21, 2008. The minor source baseline date for NO_x was already established by Yellowstone Energy Limited Partnership (formerly Billings Generation Inc.) on November 8, 1991.

In addition, DEQ clarified the permit language for the bulk loading rack VCU regarding the products that may be loaded in the event the VCU is inoperable. **MAQP #2619-24** replaced MAQP #2619-23.

On June 12, 2009, DEQ received a request from ConocoPhillips to administratively amend MAQP #2619-24 to include certain limits and standards. This amendment was in response to requirements contained in the Consent Decree (CD) that ConocoPhillips has entered into with EPA along with DEQ. The CD was set forth on December 20, 2001. As a result of the requirements set forth within the CD, ConocoPhillips had requested the following limits and standards (agreed to by EPA) to be included in the MAQP:

The NO_x emissions from the FCCU shall have a limit of 49.2 parts per million, volumetric dry (ppmvd), corrected to 0% O₂, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O₂, on a rolling 7-day average. Per Paragraph 27 of the above-referenced CD, the 7-day NO_x emission limit established for the FCC shall not apply during periods of hydrotreater outages at the refinery, provided that ConocoPhillips is maintaining and operating its FCC (including associated air pollution control equipment) in a manner consistent with good air pollution control practices for minimizing emissions in accordance with the EPA-approved good air pollution control practices plan.

As a result of this request, **MAQP #2619-25** replaced MAQP #2619-24.

On December 6, 2010, DEQ received a request from ConocoPhillips to administratively amend MAQP #2619-25 to include certain limits, standards, and obligations in response to agency requests and the requirements of Paragraph 210(a) contained the ConocoPhillips CD. ConocoPhillips also requested to include conditions pertaining to facility-related Supplemental Environmental Projects (SEP), although not specifically required by the ConocoPhillips CD. ConocoPhillips later rescinded the request to include these SEP conditions within this permit action. ConocoPhillips additionally requested removal of references to Tank #162 (Ground Water Interceptor System (GWIS) Recovered Oil Tank) as this tank has been taken out of service. With knowledge of forthcoming additional information and administrative amendment requests, in concurrence with ConocoPhillips, DEQ withheld preparation and issuance of a revised MAQP; however, this action was assigned MAQP #2619-26.

On July 28, 2011, DEQ received a request from ConocoPhillips to administratively amend MAQP #2619-25 to include the following language (underlined):

NO_x emissions shall not exceed 49.2 ppmvd corrected to 0% O₂, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O₂, on a rolling 7-day average. The 7-day NO_x emission limit shall not apply during periods of hydrotreater outages, provided that ConocoPhillips is maintaining and operating the FCCU (including associated air pollution control equipment) consistent with good air pollution control practices for minimizing emissions in accordance with the EPA-approved good air pollution control practices plan. For days in which the FCCU is not operating, no NO_x value shall be used in the average, and those periods shall be skipped in determining the 7-day and 365-day averages (ConocoPhillips Consent Decree, Paragraph 27, as amended). ConocoPhillips requested this addition in language as a result of an April 29, 2011 letter from EPA, which contained the formal approval of the FCC NO_x emission limits required by the CD. The letter included EPA's expectations as to how these NO_x emission concentration averages are to be calculated. This amendment to MAQP #2619-25 included the requested changes from the December 6, 2010, and July 28, 2011, administrative amendment requests.

As a result of both of these requests, **MAQP #2619-27** replaced MAQP #2619-25. On September 13, 2011, October 7, 2011, October 25, 2011, and October 31, 2011, DEQ received elements to fulfill a complete air quality permit application from ConocoPhillips. ConocoPhillips requested a modification to their existing air quality permit to incorporate conditions and limitations associated with the proposed installation of a Backup Coke

Crusher. A Backup Coke Crusher is necessary to ensure crushed coke is available at all times for the facility, particularly during instances when the main Coke Crusher is not operational as a result of mechanical failure and/or maintenance activities. The components of the Backup Coke Crusher include the coke crushing unit as well as a diesel fired engine and compressor.

This permit action incorporated all limitations and conditions associated with the proposed Backup Coke Crusher. **MAQP #2619-28** replaced MAQP #2619-27.

On May 3, 2012, DEQ received a request to administratively amend MAQP #2619-28 to incorporate a change in the ConocoPhillips Company name. On May 1, 2012, the downstream portions of the ConocoPhillips Company were spun-off as a separate company named Phillips 66 Company (Phillips 66). As a result of the spin-off, the former ConocoPhillips Billings Refinery is now the Phillips 66 Billings Refinery. The permit action incorporated the name change throughout, and **MAQP #2619-29** replaced MAQP #2619-28.

On October 9, 2012, DEQ received an Administrative Amendment Request to delete conditions regarding the New Crude and Vacuum Unit because the project was cancelled, clarification of various rule applicabilities and other minor edits. A letter outlining the requested changes in bullet point fashion is on file with DEQ. **MAQP #2619-30** replaced MAQP #2619-29.

On May 1, 2014, DEQ received an Administrative Amendment request from Phillips 66. Phillips 66 is in the process of taking steps to close out the Consent Decree with the Environmental Protection Agency (EPA) and the State of Montana. Phillips 66 requested that limits and standards from the Consent Decree which are required to live on beyond the life of the Consent Decree be present in the permit, with authority for those conditions to rest outside of regulatory reference to the Consent Decree itself. The action removed references to the Consent Decree as a regulatory basis. The changes taking place in this action are tabelized below. Following the first table is a table which contains additional information regarding all conditions in the MAQP which are believed to have originated through the Consent Decree. **MAQP #2619-31** replaced MAQP #2619-30.

MAQP #2619-31 Table 1: Changes taking place in this action

MAQP #2619-30 Condition	Source	Pollutant	Obligation	CD Paragraph	Prior Permit Reference	New Regulatory Reference
II.E.5.c.i	Boiler Stack	SO ₂	CEMS	71	CD	17.8.749
II.C.1.d.ii	FCC	SO ₂	7-day & 365-day limits	40	CD	17.8.749
II.C.1.d.vi	FCC	NO _x	7-day & 365-day limits	17	CD	17.8.749
II.C.1.d.iv	FCC	CO	365-day limit	50	CD	17.8.749
II.C.1.d.v	FCC	CO	1-hr limit	49	CD	17.8.749

MAQP #2619-30 Condition	Source	Pollutant	Obligation	CD Paragraph	Prior Permit Reference	New Regulatory Reference
II.C.1.d.vii	FCC	PM	1 lb/1000 lb coke burn	46, 47(a)	CD	17.8.749
II.A.1.c.v	FCC	----	NSPS J and A applicability	54	CD	17.8.749
II.C.1.d.iii	FCC	SO ₂	NSPS J limit	54	CD	17.8.749
II.C.1.d.vii	FCC	PM	NSPS J limit	54	CD	17.8.749
II.C.1.d.viii	FCC	Opacity	NSPS J limit	54	CD	17.8.749
II.E.5.b.v	FCC	NO _x	CEMS	28	CD	17.8.749
II.E.5.b.iv	FCC	CO	CEMS	49	CD	17.8.749
II.E.5.b.vi	FCC	O ₂	CEMS	28, 37	CD	17.8.749
II.E.5.b.i	FCC	SO ₂	CEMS	37	CD	17.8.749
II.E.5.b.iii	FCC	Opacity	COMS	47(b)	CD	17.8.749
II.E.4	FCC	PM	Particulate Emissions Test- annual	47(a)	CD	17.8.749
II.B.1	Flare-Refinery	SO ₂	RCFAs & FGRS	162	CD	17.8.749
II.A.1.c.iii	Flare-Refinery	SO ₂	NSPS J and A applicability	161	CD	17.8.749
II.A.1.c.iv	Flare-Jupiter	SO ₂	NSPS J and A applicability	155	CD	17.8.749
II.A.1.c.i	Heaters/Boilers	SO ₂	NSPS J applicability	69	none	17.8.749
II.C.1.e.i	Heaters	SO ₂	No fuel oil burning	**	none	17.8.749
II.C.1.e.iii	Heaters	SO ₂	Limit of 0.10 gr/dscf H ₂ S in fuel gas	69	none	17.8.749
II.C.1.f.iv	Boilers	SO ₂	Limit of 0.10 gr/dscf H ₂ S in fuel gas	69	none	17.8.749
II.C.1.f.ii	Boilers	SO ₂	300 ton/365-day rolling avg.***	71	CD	17.8.749
absent	Flare-Jupiter	SO ₂	RCFAs for NSPS J	179	none	17.8.749

*** Condition existed in MAQP prior to Consent Decree

** Not in Consent Decree but requested as part of this action

MAQP #2619-31 Table 2: All conditions originating from Consent Decree

<u>Source</u>	<u>CD Limit or Obligation</u>	<u>MAQP #2619-30 Permit Condition</u>	<u>Compliance Demonstration</u>
FCCU	365-Day Rolling Average NO _x Emission = 49.2 ppmvd @ 0% O ₂ 7-Day Rolling Average NO _x Emission = 69.5 ppmvd @ 0% O ₂ Hydrotreater Outages (7-Day Limit Shall Not Apply)	Sec. II.C.1.d.vi	Sec. II.E.5.b.v Sec. II.E.b.vi Sec. II.E.7 Sec. II.E.8
FCCU	365-Day Rolling Average SO ₂ Emission = 25 ppmvd @ 0% O ₂ 7-Day Rolling Average SO ₂ Emission = 50 ppmvd @ 0% O ₂ Hydrotreater Outages (7-Day Limit Shall Not Apply)	Sec. II.C.1.d.ii	Sec. II.E.5.b.i Sec. II.E.b.vi Sec. II.E.7
FCCU	PM Emission = 1 lb/1000 lbs coke burned	Sec. II.C.1.d.vii	Sec. II.E.4
FCCU	1-Hour Average CO Emission = 500 ppmvd @ 0% O ₂ (Startup, Shutdown, or Malfunctions not used in determining compliance with this limit. - 2nd Amendment) 365-Day Rolling Average CO Emission = 150 ppmvd @ 0% O ₂	Sec. II.C.1.d.v Sec. II.C.1.d.iv	Sec. II.E.5.b.iv Sec. II.E.7
FCCU	Must comply with NSPS Subpart A and J - SO ₂	Sec. II.A.1.a (General Condition) Sec. II.A.1.c.v (General Condition) Sec. II.C.1.d.iii (Emission Limit)	Sec. II.A.1.a (General Condition) Sec. II.A.1.c.v (General Condition) Sec. II.E.5.b.i (Emission Monitoring) Sec. II.E.7 (Emission Monitoring)
FCCU	Must comply with NSPS Subpart A and J - PM	Sec. II.A.1.a (General Condition) Sec. II.A.1.c.v (General Condition) Sec. II.C.1.d.vii (CD Emission Limit)	Sec. II.A.1.a (General Condition) Sec. II.A.1.c.v (General Condition) Sec. II.E.4 (Emission Testing)

<u>Source</u>	<u>CD Limit or Obligation</u>	<u>MAQP #2619-30 Permit Condition</u>	<u>Compliance Demonstration</u>
FCCU	Must comply with NSPS Subpart A and J - CO	Sec. II.A.1.a (General Condition) Sec. II.A.1.c.v (General Condition) Sec. II.C.1.d.v (CD Emission Limit)	Sec. II.A.1.a (General Condition) Sec. II.A.1.c.v (General Condition) Sec. II.E.5.b.iv (Emission Monitoring) Sec. II.E.7 (Emission Monitoring)
FCCU	Must comply with NSPS Subpart A and J - Opacity	Sec. II.A.1.a (General Condition) Sec. II.A.1.c.v (General Condition) Sec. II.C.1.d.viii (Emission Limit)	Sec. II.A.1.a (General Condition) Sec. II.A.1.c.v (General Condition) Sec. II.E.5.b.iii (Emission Monitoring) Sec. II.E.7 (Emission Monitoring)
Boilers	Must comply with NSPS Subpart J (SO ₂ , CO & PM) 365-Day Rolling Average SO ₂ Emissions = 300 tpy (Fuel-Oil Burning Only)	Sec. II.A.1.c.i (General Condition) Sec. II.C.1.f.ii (Emission Limit) Sec. II.C.1.f.iii (Emission Limit)	Sec. II.A.1.c.i (General Condition) Sec. II.E.5.c.i (Emission Monitoring) Sec. II.E.7 (Emission Monitoring) Sec. II.E.5.e (Emission Monitoring)
Heaters	Must comply with NSPS Subpart J (SO ₂ , CO & PM) 365-Day Rolling Average SO ₂ Emissions = 300 tpy (Fuel-Oil Burning Only)	Sec. II.A.1.c.i (General Condition) Sec. II.C.1.e.i (Operating Condition) Sec. II.C.1.f.iii (Emission Limit)	Sec. II.E.5.e (Emission Monitoring)
SRU/Ammoni um Sulfide Unit Flare (Jupiter Flare)	Must comply with NSPS Subpart A and J.	Sec. II.A.1.a (General Condition) Sec. II.A.1.c.iv (General Condition) Sec. II.C.7 (Operating Condition)	Sec. II.E.5.f
Main Plant Flare (Refinery)	Must comply with NSPS Subpart A and J.	Sec. II.A.1.a (General Condition) Sec. II.A.1.c.iii (General Condition) Sec. II.B.1 (Control Requirement) Sec. II.C.6.a (Operating Condition)	Sec. II.E.5.f

<u>Source</u>	<u>CD Limit or Obligation</u>	<u>MAQP #2619-30 Permit Condition</u>	<u>Compliance Demonstration</u>
Jupiter SRU/ATS Main Stack	Must comply with NSPS Subpart A and J.	Sec. II.A.1.a (General Condition) Sec. II.A.1.c.ii (General Condition)	
Main Plant Flare (Refinery)	Root Cause Failure Analysis	Sec. II.C.6	

On September 16, 2014, DEQ received an application from Phillips 66 to propose physical and operational changes to process units and auxiliary facilities at the refinery in order to provide more optimized operations for a broader spectrum of crude oil slates. This application was assigned **MAQP #2619-32**. Changes were primarily related to certain crude distillation, hydrogen production and recovery, fuel gas amine treatment, wastewater treatment, and sulfur recovery equipment and operations. A detailed list of project-affected equipment with a description of the changes proposed is presented below:

Summary of Project-Impacted Emissions Units			
Emissions Unit	Type of Unit (Existing/New)	Maximum Capacity	Project Impact
Small Crude Unit Heater, H-1	Existing	55.92 MMBtu/hr (HHV)	The tubes in the Small Crude Unit Heater, H-1 will be replaced with upgraded metallurgy tubes. Phillips 66 has not sought to treat this change as qualifying for one of the exemptions from what is a physical change or change in the method of operation under relevant PSD regulations.
Vacuum Furnace, H-17 – Existing Furnace	Existing	n/a	This emissions unit will be discontinued from service and replaced by a new process heater, as noted below.
Vacuum Furnace, H-17 – Replacement Furnace	New	75 MMBtu/hr (HHV)	This emissions unit will be constructed to replace the refinery's existing Vacuum Furnace, H-17, which, as noted above, will be removed from service.

Summary of Project-Impacted Emissions Units			
Emissions Unit	Type of Unit (Existing/New)	Maximum Capacity	Project Impact
FCCU Preheater, H-18	Existing	77 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project because the actual feed rate (and the gas oil content of the feedstock) to the No. 4 HDS Unit, which provides the feed to this heater, is anticipated to increase due to the project. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
Large Crude Unit Heater, H-24	Existing	108.36 MMBtu/hr (HHV)	This emissions unit will be physically modified, including the installation of upgraded metallurgy tubes to replace the existing tubes in the heater and the installation of ULNBs to replace the existing burners in the heater.
FCCU Stack	Existing	8,285.50 million barrels per year (gas oil feed)	Phillips 66 estimated that the project would result in an increase in the actual FCCU catalyst regenerator coke burn rate equal to approximately 12% of its annual average potential to emit coke burn rate. This coke burn rate increase will be associated with the actual increase in throughput and slightly heavier gas oil feedstock expected for the FCCU. The increase in throughput and gas oil feedstock density for the FCCU will occur because the No. 4 HDS Unit, which provides the feed to the FCCU, is estimated to experience an increase in the gas oil content of its feed, as well as an overall increase in its actual feed rate, as a result of the project. These changes to the No. 4 HDS Unit feed will occur because of the improved separation capabilities of the new Vacuum Unit Fractionator (W-57). The estimated increase in actual FCCU catalyst regenerator coke burn rate will make use of existing coke burn rate capacity that is not currently being utilized. The project does not propose to increase the coke burn rate capacity or the potential to emit emission rates of the FCCU catalyst regenerator.
Storage Tanks	Existing		Certain storage tanks at the refinery are anticipated to experience an increase in actual annual throughput primarily because of the improved straight run diesel and gas oil separation operations that will occur as a result of the project. This improvement in straight run diesel and gas oil separation will generally result in an increase in the throughput for diesel and gas oil storage tanks at the refinery. On the other hand, certain storage tanks at the refinery will experience a decrease in actual annual throughput as a result of the project. The refinery storage tanks expected to experience a decrease in throughput are those tanks that generally store lighter (higher vapor pressure) materials, such as gasoline and gasoline blendstocks. These actual throughput decreases have not been evaluated for PSD applicability determination purposes (<i>i.e.</i> , any emissions decreases that may result due to these throughput decreases have not been estimated because Phillips 66 does not intend to make such emissions decreases creditable). Additionally, the Desalter Break Tanks (T-4510 and T-4511) at the refinery will be removed from service and replaced by two new API separator bays (including associated equipment).

Summary of Project-Impacted Emissions Units			
Emissions Unit	Type of Unit (Existing/New)	Maximum Capacity	Project Impact
Fugitive VOC Emissions	Existing-New		New piping fugitive components (<i>e.g.</i> , pumps, compressors, pressure relief devices, open-ended valves or lines, valves, and flanges or other connectors) are expected to be added to the refinery as a result of the project due to certain piping and equipment additions that will occur as part of the project. Also, new process drains and junction boxes are anticipated to be added to the refinery as part of the project. Furthermore, the Primary OWS (T-163) at the refinery will be removed from service and replaced by two new API separator bays (including associated equipment).
CPI Separator Tanks	Existing		The OWSs (CPI OWSs (T-169 and T-170)) representing this emissions unit are planned to be removed from service and replaced by two new API separator bays (including associated equipment).
No. 4 HDS Recycle Hydrogen Heater, H-8401	Existing	31.20 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in an increase in the actual feed rate to the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 4 HDS Fractionator Feed Heater, H-8402	Existing	31.70 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in an increase in the actual feed rate to the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 1 H ₂ Unit Reformer Heater, H-9401	Existing	179.20 MMBtu/hr PSA Gas, HHV 76.80 MMBtu/hr Natural Gas/Cryo Gas, HHV	Modifications will be made to the burners in the No. 1 H ₂ Unit Reformer Heater, H-9401 (EPN 35) to improve the flame pattern of these burners and to reduce hot spots on the tubes located in this heater. The type of burner modification may include changing the angle of the burners relative to this heater's tubes. Phillips 66 has not sought to treat this change as qualifying for one of the exemptions from what is a physical change or change in the method of operation under relevant PSD regulations.

Summary of Project-Impacted Emissions Units			
Emissions Unit	Type of Unit (Existing/New)	Maximum Capacity	Project Impact
Coke Handling	Existing		Based on engineering calculations, the actual annual coke production rate of the Coker Unit is expected to increase as a result of the project due to the heavier vacuum residuum that will be sent to the Coker Unit after the implementation of the project. Therefore, the actual annual amount of coke handled at the refinery is expected to increase as a result of the project.
No. 5 HDS Charge Heater, H-9501	Existing	25.0 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project primarily because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in more diesel range material being routed to the No. 5 HDS Unit rather than the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 5 HDS Stabilizer Reboiler Heater, H-9502	Existing	49.00 MMBtu/hr (HHV)	The actual feed rate to this process heater is anticipated to increase as a result of the project primarily because the improved separation to be provided by the new Vacuum Unit Fractionator (W-57) will result in more diesel range material being routed to the No. 5 HDS Unit rather than the No. 4 HDS Unit. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 10% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
No. 2 H ₂ Unit Reformer Heater, H-9701	Existing	111.35 MMBtu/hr PSA Gas, HHV 79.65 MMBtu/hr Natural Gas/Cryo Gas, HHV	The actual feed rate to this process heater is anticipated to increase as a result of the project in order to provide a portion of the increase in hydrogen production expected to be required by the project. Phillips 66 estimated that the anticipated increase in the annual average feed rate to this process heater caused by the project would result in an increase in the heater's actual annual average firing rate equal to approximately 15% of its annual average potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being utilized. The project does not propose to increase the firing rate capacity or the potential to emit emission rates of this heater.
Coker Vent and Coke Cutting	Existing		Based on engineering calculations, the actual annual coke production rate of the Coker Unit is expected to increase as a result of the project due to the heavier vacuum residuum that will be sent to the Coker Unit after the implementation of the project. In association with this annual coke production rate increase is a decrease in coke drum cycle time. Therefore, the actual annual number of coke drum opening and coke cutting events is expected to increase as a result of the project.

Summary of Project-Impacted Emissions Units			
Emissions Unit	Type of Unit (Existing/New)	Maximum Capacity	Project Impact
Cooling Tower	New	7,000 gallons per minute	This cooling tower will be newly constructed to accommodate the increase in cooling water demand estimated to be required by the modified Vacuum Unit.
Railcar Clarified Oil Loading	Existing		The existing railcar clarified oil loading operation at the refinery is anticipated to experience an increase in annual throughput relative to the current annual throughput at which this operation typically operates due to the higher annual operating rate expected for the FCCU as a result of the project.
API Separator Tanks	New	132,058 thousand gallons per year	<p>The OWSs representing this emissions unit will replace the following equipment currently located at the refinery: (1) Desalter Break Tanks (T-4510 and T-4511); (2) Primary OWS (T-163); and (3) CPI OWSs (T-169 and T-170).</p> <p>The Oil Water Separator system includes the separator tanks themselves and associated equipment. See 40 CFR §63.1041 definition of Separator. The oil water separator system includes the slop oil vessel (T-4526) and Sludge Hopper (T-4527).</p>
Jupiter Main Stack No. 1	Existing		SRU No. 1, which emits through this stack, will experience multiple physical changes to accommodate a portion of the increased amount of sulfur-containing compounds that will be routed to the Jupiter Plant as a result of the project.
Jupiter Main Stack No. 2	New		SRU No. 3, which will emit through this stack, will be newly constructed as part of the project to accommodate a portion of the increased amount of sulfur-containing compounds that will be routed to the Jupiter Plant as a result of the project.
Jupiter Cooling Tower, CT-615A/B/C	New	7,500 gallons per minute	This cooling tower will be newly constructed to accommodate the increase in cooling water demand estimated to be required by the Jupiter Plant as a result of the project.
Jupiter Cooling Tower CT-120	New	11,500 gallons per minute	This cooling tower will replace the existing cooling tower located at the Jupiter Plant. This Cooling Tower was approved via de minimis after initial permitting of the Vacuum Improvement Project. As required by the de minimis provisions of ARM 17.8.745, review occurred to ensure the emissions from the cooling tower would not have triggered need for PSD permitting for the Vacuum Improvement Project.
Jupiter Sulfur Storage Tanks	Existing-New		The two existing atmospheric sulfur storage tanks (V-117 and V-355) at the refinery may experience an increase in actual annual throughput due to improved sulfur recovery operations of the respective SRUs associated with these tanks and an increase in sulfur loading to the same respective SRUs. Additionally, a new atmospheric sulfur storage tank (V-370) is proposed to be installed at the refinery as part of the project.
Jupiter Railcar and Tank Truck Sulfur Loading	Existing-New		The existing railcar and tank truck sulfur loading arms at the refinery may experience an increase in actual annual throughput as a result of the project. Additionally, one new railcar sulfur loading arm and one new tank truck sulfur loading arm are planned to be installed at the refinery as part of the project.

On September 21, 2015, DEQ received an administrative amendment request from Phillips 66 to clarify certain provisions and emission limits that were initially adopted under the consent decree. The revisions also address the triggering of 40 CFR 60 Subpart Ja for certain units, including flares. Per 40 CFR 60 Subpart Ja, flares which have triggered Subpart Ja and were meeting Subpart J requirements pursuant to a federal consent decree, will continue to meet those requirements until November 11, 2015, at which time all the requirements of Subpart Ja will apply. The requested permit changes included clarification of how the modified flares will comply before and after November 11, 2015. **MAQP #2619-33** replaced MAQP #2619-32.

On March 14, 2016, DEQ received from Phillips 66 a request for an administrative amendment of the MAQP. Changes requested include updating information regarding the cooling towers to be installed as part of the Vacuum Improvement Project to reflect changes made and approved through the de minimis provisions of ARM 17.8.745, and to correct an error regarding identification of tanks which will be removed from service as part of the Vacuum Improvement Project. Lastly, the letter received on March 14th provided notice regarding a change in stack height for the Large Crude Unit Heater H-24, from 152 feet to 195 feet 10 inches. No revision to the MAQP was necessary for the stack height change and a separate de minimis approval letter was sent to Phillips 66 regarding this change. **MAQP #2619-34** replaced MAQP #2619-33.

On April 24, 2017 DEQ received from Phillips 66 a request for an administrative amendment of the MAQP to clarify equipment associated with the API Separator System being installed as part of the Vacuum Improvement Project. Specifically, this permit update clarifies that the API Separator System includes the “Slop Oil Vessel T-4526” and the “Sludge Hopper T-4527”. P66 has requested this clarification to ensure that equipment installed on-site is understood to have been included at the time of permitting of the Vacuum Improvement Project. DEQ agreed, and noted that the Separator System consists of equipment which includes the aforementioned units, and in fact, the definition of a Separator in relevant federal rules includes not only the separation unit itself but also the forebay and other separator basins and sludge hoppers, amongst other equipment (see 40 Code of Federal Regulations (CFR) §63.1041). Section II.J.7 of the MAQP was updated to reflect the separator system.

The permit was also updated to reflect the de minimis addition of a residuum tank, identified as Tank # T-0852, to condition II.A.3.c. This tank will hold crude distillation residuum and will allow the existing Tank 107 to be temporarily taken out of service for inspections. **MAQP #2619-35** replaced MAQP #2619-34.

On March 29, 2018, DEQ received from Phillips 66 an application to modify the oxides of nitrogen (NO_x) emissions limitations associated with the No. 1 H₂ Plant Reformer Heater, H-9401. Based on source testing, the 0.030 pound per million british thermal units (lb/MMBtu) NO_x emissions limit was found not achievable. Because this heater was modified as part of the Vacuum Improvement Project, the current action entails a Prevention of Significant Deterioration (PSD) lookback to this project. The analysis as completed at that time is essentially re-worked utilizing the higher NO_x emissions

factor now applied to the heater. The netting analysis is included in the permit analysis, and the increases do not change the status of the Vacuum Improvement Project as not triggering PSD for NO_x.

Additional information was received on April 23rd regarding the limit and determination of applicable federal rules. On April 24, 2018, DEQ received an affidavit of publication of public notice, completing the application.

This permit action modified NO_x limits associated with this heater to 0.042 lb/MMBtu. **MAQP #2619-36** replaced MAQP #2619-35.

On December 20, 2018, DEQ received from P66 an application to modify the MAQP and Title V to add two backup engines to the facility, a 665 horsepower (hp) portable backup fire pump and a 300 hp emergency backup engine for redundant HDS Flare Drum Pumps. A limit of operation of 1,000 hours is proposed for the Flare Drum Pump engine. Both engines are to be Tier III rated. At the request of P66, the permit action incorporated these engines and corresponding limitations. **MAQP #2619-37** replaced MAQP #2619-36.

On January 10, 2020, DEQ received from Phillips 66 Company an application to change particulate matter emissions limitations associated with the Sulfur Recovery Operations. Following construction and commencement of operation of modifications made in support of and permitted as part of the Vacuum Improvement Project in MAQP #2619-32, the emissions of particulate matter as measured by Environmental Protection Agency (EPA) Methods 201a and 202 were found to be in excess of that allowed by permit conditions.

Following extensive review by Phillips 66 and Jupiter Sulphur, LLC to minimize emissions including condensable emissions, based on additional source testing, the limitations were determined unachievable. The current action increases the allowable emissions from Main Stack 1 and 2 to levels proposed as achievable by Phillips 66. Because these limits were established as part of the Vacuum Improvement Project, and the limits served in part to define allowable emissions which ensured the project did not exceed thresholds triggering the Prevention of Significant Deterioration (PSD) requirements of ARM 17.8 Subchapter 8, the current action is reviewed as if re-permitting the action of MAQP #2619-32. In doing so, the project triggers PSD for particulate matter, particulate matter with aerodynamic diameter of 10 microns or less, and particulate matter with aerodynamic diameter of 2.5 microns or less. The project also triggers PSD for greenhouse gasses. On March 3, 2020, DEQ received modified application information in response to an incompleteness letter.

MAQP #2619-38 increases allowable particulate matter related emissions from Jupiter Main Stacks 1 and 2, and reviews greenhouse gas best available control technology for the physically modified and new emitting units associated with the Vacuum Improvement Project.

On September 23, 2020, DEQ received from Phillips 66 an MAQP application for significant changes to the refinery. The application triggers the Prevention of Significant

Deterioration (PSD) program requirements of ARM 17.8 Subchapter 8 for oxides of nitrogen (NO_x), particulate matter with an aerodynamic diameter of 2.5 microns and less (PM_{2.5}), particulate matter with an aerodynamic diameter of 10 microns or less (PM₁₀), and greenhouse gases (GHGs). The project also triggers PSD for ozone based on NO_x.

The refinery is currently designed to refine heavy sour crude oil. In general, this permitting action is a conglomeration of several projects which will ultimately provide Phillips 66 the ability to process crude oils that contain higher percentages of residual material while also maintaining compliance with fuel sulfur content requirements (i.e. – process heavier, sour crude). Physical changes are expected to the crude units, coker unit, fluidized catalytic cracking unit (FCCU), the propylene and butylene mercaptan extracting unit (PB Merox Unit), and the sulfur recovery units (SRUs) at the adjacent Jupiter plant. Additionally, a new hydrogen plant, hydrogen plant #3, will be installed. Changes in operation will also affect emissions from several existing heaters and unit operations including the delayed coking unit.

The permit analysis contains a table detailing all changes proposed to project affected emitting units, as well as a presentation of the net emissions changes, best available control technology (BACT) determinations, and a summary of the ambient air quality impacts including increment consumption.

Relevant permit conditions have been included throughout the permit. In addition, conditions created relevant to the Vacuum Improvement Project, which originally had its own section, have been incorporated into the rest of the permit.

Emissions Unit	Existing/ New Unit	Project Impact
Catalytic Reforming Unit #2 (H-13) (EPN 64)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 2.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.

Emissions Unit	Existing/ New Unit	Project Impact
Catalytic Reforming Unit #2 (H-14) (EPN 65)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 2.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.
Sat Gas Stabilizer Reboiler (H-16) (EPN 67)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 2.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.
FCCU Preheater (H-18) (EPN 69)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may use all the heater's existing firing rate capacity that is not currently being used. Phillips 66 is not proposing to increase the firing rate capacity of the heater.
Alky Heater (H-21) (EPN 71)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the process heater's annual actual firing rate to increase by an amount equal to approximately 12.5% of its annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.

Emissions Unit	Existing/ New Unit	Project Impact
Catalytic Reforming Unit #2 (H-23) (EPN 72)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 2.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.
Coker Furnace (H-3901) (EPN 74)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may use all the heater's existing firing rate capacity that is not currently being used. Phillips 66 is not proposing to increase the firing rate capacity of the heater.
No. 4 HDS Recycle Hydrogen Heater (H-8401) (EPN 75)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 7.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.
No. 4 HDS Fractionator Feed Heater (H-8402) (EPN 76)	Existing	The actual feed rate to the heater is anticipated to increase as a result of the project. Phillips 66 estimated that the project may cause the combined annual actual firing rate of the process unit's process heaters to increase by an amount equal to approximately 7.5% of their combined annual potential to emit firing rate. This estimated increase in actual firing rate will make use of existing firing rate capacity that is not currently being used. As such, Phillips 66 is not proposing to increase the firing rate capacity of the heater.

In addition to the above, a new cooling tower will be installed at the Jupiter Sulphur plant. This cooling tower will replace the existing CT-602 cooling tower. The new cooling tower will be of increased capacity. An addendum to the original application was received on October 23, 2020, to request this change be added to the permit application. **MAQP #2619-39** replaced MAQP #2619-38.

On January 6, 2021, DEQ received from Phillips 66 an MAQP application to change the form of limits on the Vacuum Furnace (H-17) and Large Crude Unit Heater (H-24) regarding emissions of oxides of nitrogen (NO_x). Limits on these heaters were

originally in the form of a pound per million British thermal unit basis (lb/MMBtu), 30 day rolling average, determined daily, with a daily F-factor determination required. This form of limit requires daily refinery fuel gas analyses, producing a compliance demonstration burden that Phillips 66 preferred to forego. Phillips 66 proposed to revise the form of these emission limitations to an equivalent limit on a parts per million basis. Doing so required that only the concentration of NO_x and oxygen in the stack be measured.

Specifically, Phillips 66 requested that the 0.030 lb/MMBtu limitation on the H-17 heater be changed to a 30 parts per million by volume limitation on a dry basis (ppmvd), at 0% oxygen, on a 30 day rolling average, determined daily. The 0.040 lb/MMBtu limitation on the H-24 was requested to be changed to a 40 ppmvd at 0% oxygen limitation, determined daily on a 30-day rolling average basis. The request resulted in no increase in allowable emissions. A change in emissions monitoring followed, requiring the ppmvd monitoring requirements of 40 Code of Federal Regulations Part 60, Subpart Ja, which is also applicable to these heaters. These limitations are considered equivalent, as demonstrated by 40 CFR 60 Subpart Ja. **MAQP #2619-40** replaced MAQP #2619-39.

On May 4, 2021, DEQ received from Phillips 66 an MAQP application to reinstate flexible limitations on 4 heaters with respect to emissions of oxides of nitrogen (NO_x). It was requested that the Coker Heater H-3901, the No. 4 Hydrodesulfurization Recycle Hydrogen Heater H-8401, the No. 4 Hydrodesulfurization Fractionator Feed Heater H-8402, and the No. 1 Hydrogen Plant Reformer Heater H-9401 be placed under a bubble limit at 17.22 lb/hr and 75.44 tons per year. The request was incorporated as **MAQP #2619-41**, replacing MAQP #2619-40.

On October 29, 2021, DEQ received an application from Phillips 66 to modify the current MAQP. Phillips 66 identified that a physical change at the facility will increase the maximum hourly gas oil throughput rate for the FCCU. The allowable annual average gas oil throughput rate of the FCCU would remain the same; therefore, no change to the allowable annual emissions from the unit would result. However, an increase in the maximum hourly emissions rates may occur. This affects the original ambient air quality analyses for short term particulate matter impacts reviewed in the issuance of MAQP #2619-39. The current action addresses the change in emissions and associated impacts in the ambient impact analyses section of the permit analysis. The DEQ concludes that this update to the project permitted in MAQP #2619-39 would not change the original determination that it would not cause or contribute to an ambient air quality or ambient increment exceedance.

In addition, numerous permit cleanup items including the shutdown or removal of various emitting units are addressed in this action. These changes are tableized below. **MAQP #2619-42** replaced MAQP #2619-41.

Permit Condition	Proposed Permit Condition Revision
<ul style="list-style-type: none"> II. Conditions and Limitations.C.7.f II. Conditions and Limitations.H.1 	Phillips 66 proposes to remove the H-2, H-4, H-5, and H-19 heater entries from the referenced permit conditions because the stacks of these idled heaters are being removed from the site, which will make the heaters effectively inoperable.
Permit Condition	Proposed Permit Condition Revision
<ul style="list-style-type: none"> II. Conditions and Limitations.C.7.f II. Conditions and Limitations.H.1 	Phillips 66 proposes to remove the H-15 heater entries from the referenced permit conditions because the idled heater is being removed from the site.
<ul style="list-style-type: none"> II. Conditions and Limitations.A.3.d II. Conditions and Limitations.A.3.f II. Applicable Rules and Regulations.C.10.e 	Phillips 66 proposes to remove Proto Gas Tanks #2901 - #2907 from the referenced permit conditions because the tanks are out of service since the knock engines (engines used to measure gasoline and blending component octane ratings) previously fed by the tanks are no longer used. The knock engines have been replaced by analyzers that do not rely on sample materials from the tanks.
<ul style="list-style-type: none"> II. Conditions and Limitations.A.1.f II. Applicable Rules and Regulations.C.8.g 	Phillips 66 proposes to remove the T-36 tank entries from the referenced permit conditions because the tank has been removed from the site.
<ul style="list-style-type: none"> II. Conditions and Limitations.A.1.f II. Conditions and Limitations.A.1.g II. Conditions and Limitations.C.10 II. Applicable Rules and Regulations.C.8.g II. Applicable Rules and Regulations.C.8.h 	Phillips 66 proposes to remove the T-3201 tank entries from the referenced permit conditions because the tank has been removed from the site.
<ul style="list-style-type: none"> II. Conditions and Limitations.A.1.i II. Applicable Rules and Regulations.C.8.k 	Phillips 66 proposes to remove the Corrugated Plate Interceptor (CPI) separators entries from the referenced permit conditions because the CPI separators have been removed from the site. The replacement API separators were installed at the site as authorized by MAQP No. 2619-32, not MAQP No. 1821-32 as currently referenced.
<ul style="list-style-type: none"> II. Conditions and Limitations.C.18 	Phillips 66 proposes to remove the referenced permit condition because a de minimis notification was submitted to MT DEQ on October 8, 2021, in which Phillips 66 proposed to place the T-4510 and T-4511 tanks back in service.
<ul style="list-style-type: none"> II. Conditions and Limitations.C.7.u.i 	Phillips 66 proposes to remove the referenced permit condition because it is duplicative of II. Conditions and Limitations.C.7.p.ii.

Permit Condition	Proposed Permit Condition Revision
<ul style="list-style-type: none"> II. Conditions and Limitations.C.7.y 	Phillips 66 proposes to remove the referenced permit condition because it is duplicative of II. Conditions and Limitations.C.7.p.i. However, be sure to add an ARM 17.8.752 citation to II. Conditions and Limitations.C.7.p.i. when the referenced permit condition is removed.
<ul style="list-style-type: none"> II. Conditions and Limitations.C.7.z 	Phillips 66 proposes to remove the referenced permit condition and transfer its emission standards to subparagraphs under II. Conditions and Limitations.C.7.p for the No. 1 H ₂ Plant Reformer Heater (H-9401) and II. Conditions and Limitations.C.7.t for the No. 2 H ₂ Plant Reformer Heater (H-9701), respectively.
<ul style="list-style-type: none"> II. Conditions and Limitations.A.1.m II. Conditions and Limitations.A.3.g II. Conditions and Limitations.C.20.b II. Conditions and Limitations.C.20.c II. Conditions and Limitations.F.10 II. Applicable Rules and Regulations.C.8.l II. Applicable Rules and Regulations.C.10.f 	Phillips 66 proposes to revise the "Backup Emergency Generator for the HDS Flare Drum Pump" engine description used in the referenced permit conditions to "Emergency Generator Engine (G-8401) for the HDS Flare Drum Backup Pumps."
<ul style="list-style-type: none"> II. Conditions and Limitations.F.14 	Phillips 66 proposes to add the following sentence after the second sentence in the permit condition to document EPA Method 2510B is an equivalent method that has been approved by MT DEQ: "Phillips 66 has been approved by the department to utilize EPA Method 2510B to determine conductivity."

On April 20, 2022, DEQ received from Phillips 66, an administrative amendment request to reduce allowable emissions from the Fluid Catalytic Cracking Unit. In review of emissions inventory estimation methodologies, Phillips 66 discovered an error in calculated emissions of oxides of nitrogen (NO_x), and carbon monoxide (CO), from the fluid catalytic cracking unit (FCCU). The emissions were calculated to be higher than actual. Because these previously reported emissions from the FCCU were utilized to calculate net emissions increases for previous project(s), Phillips 66 proposed to reduce allowable future emissions from the FCCU to maintain validity of previous conclusions regarding the project(s).

This permitting action placed a limit on CO emissions from the FCCU at 66.0 tons per year, and NO_x to 59.64 tons per year. The CO limit ensured that allowable emissions of CO from the FCCU did not trigger the requirements of the Prevention of Significant Deterioration

program as found in ARM 17.8 subchapter 8. The NO_x limit set the potential to emit using a corrected emissions factor. **MAQP #2619-43** replaced MAQP #2619-42.

On May 13, 2022, DEQ received from Phillips 66 an application triggering the Prevention of Significant Deterioration requirements of ARM 17.8 Subchapter 8 (PSD).

Phillips 66 discovered that an error was made in the calculation of the CO and NO_x emission rates that were reported for the FCCU Stack (EPN 86) in the site's 2018 and 2019 emissions inventories. Those reported emission rates were used as the emissions unit's 2018 and 2019 baseline actual CO and NO_x emission rates in the Billings Projects for 2022 PSD applicability analysis calculations – a project permitted as MAQP #2619-39. However, the corrected 2018 and 2019 CO and NO_x emission rates are lower than the 2018 and 2019 CO and NO_x emission rates that were reported for the emissions unit. Therefore, Phillips 66 is proposing to revise the emissions unit's 2018 and 2019 baseline actual CO and NO_x emission rates used in the project's PSD applicability analysis calculations so that they equal the unit's corrected 2018 and 2019 CO and NO_x emission rates. Also, after further analysis, Phillips 66 proposed to revise the post-project annual potential to emit CO emission rate for the FCCU Stack. In combination, these updates had the following impacts on the project's PSD applicability analysis:

- The project resulted in a significant net emissions increase in CO, thus making the project subject to PSD review for CO; and
- The project continued to result in a significant net emissions increase in NO_x, but the increase will be greater than previously calculated and reviewed.

Therefore, DEQ re-permitted this project, going through PSD for CO, and re-assessed the impacts of increased emissions changes for NO_x. This action did not change the capacities or proposed operation of the units permitted in the Billings Projects for 2022, but the FCCU Stack's allowable emissions of CO and NO_x on an annual basis was increased to allow for operation at the design capacities that Phillips 66 required. **MAQP 2619-44** replaced MAQP #2619-43.

C. Current Permit Action

On September 5th, 2023, DEQ received from Phillips 66 an application to modify their MAQP based on changes to the refinery under the Vacuum Improvement Project (VIP). VIP included improvements in crude unit distillation capabilities and wastewater treatment facilities, an increase in hydrogen production capabilities, and an expansion of the Jupiter Sulphur, LLC (Jupiter) sulfur recovery facilities at the existing refinery.

With this submittal, Phillips 66 is proposing to include two new NO_x and SO₂ emission limitations for two of the affected units affected by the VIP (i.e. Large Crude Unit Heater H-24 and Vacuum Furnace H-17). This submittal keeps VIP non-major modification for NO_x and SO₂ under the PSD program.

In addition, Phillips 66 is requesting the following:

- Revise the SO₂ emission limitation addressed in MAQP #2619-39 for the fluid catalytic cracking unit (FCCU). DEQ did not approve of this change.
- Clarify the SO₂ emission limitation addressed in MAQP #2619-32 for the Jupiter Sulfur Recovery Unit (SRU) Main Stack #2.
- Removal of Compressor C-23 as well as its permit terms and conditions.
- Clarify the applicability of certain new source performance standards (NSPS) to further streamline requirements for refinery operations.

MAQP #2619-45 replaces MAQP #2619-44.

D. Response to Public Comments

DEQ received a letter on October 30, 2023 from the Western Environmental Law Center on behalf of the Montana Environmental Information Center.

DEQ is aware of the recent district court opinion in *Held v. State*, ruling the statutory prohibition on including greenhouse gas analyses in MEPA reviews unconstitutional.¹ That decision is being appealed to the Montana Supreme Court and final resolution is yet unsettled. While litigation is ongoing, and consistent with the court order, DEQ has started a process to assess and improve our environmental review processes, including consideration of future climate impact analyses.

¹ *Held v. State*, No. CDV-2020-307 (Mont. 1st Jud. Dist. Ct. Aug. 14, 2023).

E. Additional Information

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

II. Applicable Rules and Regulations

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

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

1. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.
2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of DEQ, provide the facilities and necessary equipment, including instruments and sensing devices, and shall conduct tests, emission or

ambient, for such periods of time as may be necessary using methods approved by DEQ. Phillips 66 shall also comply with monitoring and testing requirements of this permit.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by DEQ, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq.*, MCA. Phillips 66 shall comply with all requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from DEQ upon request.
4. ARM 17.8.110 Malfunctions. (2) The DEQ must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.
5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means which, without resulting in reduction in the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner that a public nuisance is created.

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

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.221 Ambient Air Quality Standard for Visibility
8. ARM 17.8.223 Ambient Air Quality Standard for PM₁₀

Phillips 66 must comply with the applicable ambient air quality standards. See Section V Ambient Air Impact Analysis.

C. ARM 17.8, Subchapter 3 - Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged to an outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, Phillips 66 shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.
3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.
4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.
5. ARM 17.8.316 Incinerators. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any incinerator, particulate matter in excess of 0.10 grains per standard cubic foot of dry flue gas, adjusted to 12% carbon dioxide and calculated as if no auxiliary fuel had been used. Further, no person shall cause or authorize to be discharged into the outdoor atmosphere from any incinerator emissions that exhibit an opacity of 10% or greater averaged over 6 consecutive minutes.
6. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. (4) Commencing July 1, 1972, no person shall burn liquid or solid fuels containing sulfur in excess of 1 pound of sulfur per million Btu fired. (5) Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions. Phillips 66 will burn RFG gas, PSA gas, or natural gas, which will meet this limitation.
7. ARM 17.8.324 Hydrocarbon Emissions--Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.
8. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR Part 60, NSPS. Phillips 66 is considered an NSPS affected facility under 40 CFR Part 60. Below is a summary of applicability review:
 - a. Subpart A - General Provisions, applies to all equipment or facilities subject to an NSPS Subpart as listed below.
 - b. Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units shall apply to all affected boilers at the

facility which were constructed after June 19, 1984 and are larger than 100 MMBtu/hr. Affected facilities that also meet the applicability requirements under Subpart J or Ja are subject to the PM and NO_x standards under this subpart and the SO₂ standards of Subpart J or Ja. Boilers B-5 and B-6 are subject to this subpart as well as Subpart J.

- c. Subpart J - Standards of Performance for Petroleum Refineries, applies to:
 - 1. All of the heaters and boilers at the Phillips 66 refinery, as a requirement of a consent decree if not also through the rule itself (except those subject to or electing to comply with Subpart Ja);
 - 2. The Fluid Catalytic Cracking Unit (FCCU). “Modification” or “reconstruction” of this unit has not occurred, therefore, NSPS J continues to apply as originally set by consent decree and continually required by the MAQP for CO, SO₂, PM and opacity provisions (ARM 17.8.749); and
 - 3. Any other affected equipment
- d. Subpart Ja - Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, shall apply to:
 - 1. The No. 3 H₂ Plant Heater H-8501 installed as part of the MAQP #2619-39 project.
 - 2. Vacuum Furnace H-17 installed as part of the Vacuum Improvement Project permitted in MAQP 2619-32 (upon startup of H-17).
 - 3. Large Crude Unit Heater H-24 resulting from the Vacuum Improvement Project permitted in MAQP 2619-32 (upon startup after reconstruction of H-24).
 - 4. Sulfur Recovery Units. The post-Vacuum Improvement Project sulfur recovery plant permitted in MAQP #2619-32 (SRU No. 1, 2, and 3, including the sulfur pits associated with these units,) became subject to Subpart Ja as a result of that project. As the PSD analysis associated with the Vacuum Improvement Project relied on all Sulfur Recovery Units being subject to the requirements of NSPS Ja, applicability was also required in overlapping fashion through authority of ARM 17.8.749. In MAQP #2161-39, the installation of equipment that will provide all three SRUs with the capability to operate utilizing oxygen enrichment was proposed; therefore, the units continue to be subject to NSPS Ja, with Equation 1 at 40 CFR 60.102a(f)(1)(i) applicable during such operations.
 - 5. Delayed Coking Unit.

6. Jupiter Sulfur Plant Flare (Jupiter Flare, also known as the SRU/Ammonium Sulfide Unit Flare).
 7. Refinery Flare (Excess Fuel Gas Flare Header and Relcif Flare Header).
 8. Any other affected equipment.
- e. Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids, applies to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after May 18, 1978, and prior to July 23, 1984, for equipment not overridden by 40 CFR 63, Subpart CC. The affected tanks include, but are not limited to:

<u>Tank ID</u>	<u>Contents</u>
T-100*	Asphalt
T-101*	Asphalt
T-102	Naphtha
T-104*	Vacuum Resid

* *Currently exempt from all emission control provisions due to vapor pressure of materials stored.*

- f. Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels, applies to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984, for equipment not overridden by 40 CFR 63, Subpart CC. The affected tanks include, but are not limited to, the following:

<u>Tank ID</u>	<u>Contents</u>
T-35	Slop oil
T-72	Gasoline
T-107*	Residue
T-110	Material with a max true vapor pressure of 11.1 psia
T-0851	(No. 5 HDS Feed Storage Tank)
T-1102	(Crude Oil Storage Tank)
T-2909	Gasoline – Low Sulfur

* *Currently exempt from all emission control provisions due to vapor pressure of materials stored.*

- g. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries, applies to the cryogenic unit, C3901 Coker Unit Wet Gas Compressor; C-5301 Flare Gas Recovery Unit Liquid Ring Compressor; C-5302 Flare Gas Recovery unit Liquid Ring Compressor; C-8301 Cryo Unit Inlet Gas Compressor; C-8302 Cryo Unit Refrigerant Compressor; C-8303 Cryo unit Regeneration Gas Compressor; C-26 FCCU Wet Gas Compressor, and any other applicable equipment constructed or modified after November 7, 2006.

The C-8401 No. 4 HDS Makeup/Recycle Hydrogen Compressor, C-7401 Hydrogen Makeup/Reformer Hydrogen Compressor, C-9401 Hydrogen Plant Feed Gas Compressor, C-9501 Makeup/Recycle Gas Compressor, and C-9701 Feed Gas Compressor are in hydrogen service.

- h. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006, applies to the C-8402 Makeup/Recycle Hydrogen Compressor and No. 4 HDS Makeup/Recycle Compressor which are in hydrogen service, as well as any other applicable equipment constructed, reconstructed, or modified after November 7, 2006 including the following:
- 1) Delayed coker unit
 - 2) Cryogenic unit
 - 3) Hydrogen membrane unit
 - 4) Gasoline merox unit
 - 5) Crude Units
 - 6) Gas oil hydrotreater unit (consisting of a reaction section, fractionation section, and an amine treating section)
 - 7) No. 1 H₂ Unit (22.0-million standard cubic feet per day (MMscfd) hydrogen plant feed system)
 - 8) Alkylation Unit Butane Defluorinator Project (consisting of heat exchangers; X-453, X-223, X-450, X-451, X-452, pumps; P-646, Vessels; D-130, D-359, D-360)
 - 9) Alkylation Unit Depropanizer Project
 - 10) #3 Sour Water Stripper (SWS) Unit
 - 11) Fugitive components associated with boilers #B-5 and #B-6
 - 12) The fugitive components associated with the No.2 H₂ Unit and the No.5 HDS Unit
 - 13) HPU
 - 14) FCCU
 - 15) PB Merox Unit

16) No. 3 Hydrogen Plant

- i. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems applies to the coker unit drain system, desalter wastewater break tanks, gas oil hydrotreater, No.1 Hydrogen Unit (20.0-MMscfd hydrogen plant), C-23 compressor station, Alkylation Unit Butane Defluorinator Project, Alkylation Unit Depropanizer Project, the individual drain system in the No.2 H₂ Unit, the individual drain system in the No 3 H₂ Unit, the aggregate facility of the Vacuum Unit including the main oily wastewater sump through and including the two new parallel API OWSs and Tank T-164 as proposed in MAQP 2619-32 and the No. 5 HDS Unit, Tank T-4523, and any other applicable equipment, for equipment not overridden by 40 CFR 63 Subpart CC.
 - j. Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines applies to the diesel fired engines used for operation of the Backup Coke Crusher, the Backup Firepump Engine, and the Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps and any other applicable engines
 - k. All other applicable subparts and referenced test methods.
9. ARM 17.8.341 Emission Standards for Hazardous Air Pollutants. Phillips 66 shall comply with the standards and provisions of 40 CFR Part 61, as listed below:
- a. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP Subpart as listed below.
 - b. Subpart FF - National Emission Standards for Benzene Waste Operations applies, applies to the refinery's existing sewer system (including maintenance and water draw down activities of the LSG tank involving liquids that may include small concentrations of benzene), the new individual drain system for the waste streams associated with the new No. 3 H₂ Plant, and Tanks 34 and 35.
 - c. Subpart M - National Emission Standard for Asbestos shall apply to, but not be limited to, the demolition and/or renovation of regulated asbestos containing material.
10. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as listed below:
- a. Subpart A - General Provisions, applies to all NESHAP source categories subject to a Subpart as listed below.

- b. Subpart R - National Emission Standards for Gasoline Distribution Facilities, shall apply to, but not limited to, the Bulk Loading Rack.
- c. Subpart CC - National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries (Refinery MACT I). This MACT contains standards for miscellaneous process vents, storage vessels, wastewater streams and treatment, equipment leaks, gasoline loading racks, decoking operations, and heat exchange systems at refineries. The crude units, coker unit, FCCU, and PB Merox Unit modified as described for MAQP #2619-39 will not undergo “reconstruction” under this subpart, and therefore will continue to remain subject under relevant existing source requirements.

The new No. 3 H₂ Plant permitted as part of MAQP #2619-39 will include new wastewater collection systems subject to this subpart. Additionally, new plant piping fugitive components in organic service, and new heat exchangers installed as part of the MAQP #2619-39 project will be subject.

- d. Subpart UUU - National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries affect Catalytic Cracking Units, Catalytic Reforming Units, and Sulfur Recovery Units (Refinery MACT II) and applies to the FCCU, and the Catalytic Reforming Unit #2. Subpart UUU does not apply to the Catalytic Reforming Unit #1 as long as the reformer is dormant or the catalyst is regenerated off-site.

The FCCU will not undergo “reconstruction” due to the modifications as described for MAQP #2619-39 and therefore will continue to be subject to the existing FCCU provisions.

SRU #2 will have modifications as described in MAQP #2619-39, which will cost greater than 50% of the fixed capital cost for a comparable new unit. As such, SRU #2 will become subject to the new SRU provisions.

- e. Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines, applies to the diesel-fired engine used for operation of the Backup Coke Crusher, the Cryo Backup Air Compressor engine, the Boiler House Air Compressor engine, the Pump for Storm Water to Holding Pond engine, the Backup Firepump Engine, the Emergency Generator Engine (G-8401) for the HDS Flare Drum Pumps, the Boiler House Backup Air Compressor engine, and any other applicable engines.
- f. Subpart DDDDD – National Emissions Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters, affects the numerous process heaters, as well as the boilers, at the refinery.

The No. 3 H₂ Plant Reformer Heater H-8501 proposed to be installed as part of MAQP #2619-39 will be subject to this rule as a unit with heat input

greater than 10 MMBtu/hr, designed to burn gas category 1 gas. The unit is not expected to be installed with a continuous oxygen control system, and therefore, will be subject to annual tune-ups.

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

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.
2. ARM 17.8.402 Requirements. Phillips 66 must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP).

E. ARM 17.8, Subchapter 5 - Air Quality Permit Application, Operation and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to DEQ. The current permitting action is re-permitting a major modification of a major stationary source, and as such, a fee of \$3,500 was required. DEQ received the appropriate fee on May 17, 2022.
2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to DEQ by each source of air contaminants holding an air quality permit, excluding an open burning permit, issued by DEQ. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

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

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

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.
2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify or use any air contaminant sources that have the PTE greater than 25

tons per year of any pollutant. Phillips 66 has the PTE greater than 25 tons per year of PM, PM₁₀, PM_{2.5}, NO_x, CO, VOC, and SO₂; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.
4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.
5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, modification, or use of a source. Phillips 66 submitted the appropriate application for this action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. Phillips 66 made public notice of the application in the *Billings Gazette* on May 13, 2022.
6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by DEQ must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.
7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.
8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by DEQ at the location of the source.
9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving Phillips 66 of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq.*
10. ARM 17.8.759 Review of Permit Applications. This rule describes DEQ's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.
11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued

prior to construction of a new or modified source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).
13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with

ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.
14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to DEQ.
15. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to DEQ for incineration facilities subject to 75-2-215, MCA.

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

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.
2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications -- Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

Phillips 66's existing petroleum refinery in Billings is defined as a "major stationary source" because it is a listed source with the PTE more than 100 tons per year of several pollutants (PM, PM₁₀, PM_{2.5}, SO₂, NO_x, CO, and VOCs).

The current permitting action is revisiting a previously permitted major modification of a major stationary source (MAQP #2619-39 for Billings Projects for 2022). The project requires additional PSD review for CO due to a correction of an error which revealed that there is a significant net increase in CO associated with it. NO_x emissions were subject to PSD review during the initial major source permitting; however, this action increased the allowable levels of NO_x associated with that project and therefore included a PSD review at the higher allowable NO_x levels.

H. ARM 17.8, Subchapter 10 - Preconstruction Permit Requirements for Major Stationary Sources or Modifications Located Within Attainment or Unclassified Areas, including, but not limited to:

1. ARM 17.8.1004 When Montana Air Quality Permit Required. (1) Any new major stationary source or major modification which would locate anywhere in an area designated as attainment or unclassified for a NAAQS under 40 CFR 81.327 and which would cause or contribute to a violation of a NAAQS for any pollutant at any locality that does not or would not meet the NAAQS for that pollutant, shall obtain from DEQ a MAQP prior to construction in accordance with subchapters 7 and 8 and all requirements contained in this subchapter if applicable.

The Phillips 66 Company Billings refinery is located in an area designated as attainment/unclassifiable for all pollutants. The nearest non-attainment area is in Laurel, an SO₂ nonattainment area centered around the CHS refinery. The current project does not pose a significant emissions increase of SO₂.

I. ARM 17.8, Subchapter 12 - Operating Permit Program Applicability:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any stationary source having:
 - a. PTE > 100 TPY of any pollutant;
 - b. PTE > 10 TPY of any one HAP, PTE > 25 TPY of a combination of all HAPs, or a lesser quantity as DEQ may establish by rule; or
 - c. PTE > 70 TPY of PM₁₀ in a serious PM₁₀ nonattainment area.
2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204 (1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #2619-45 for Phillips 66, the following conclusions were made:

- a. The facility's PTE is greater than 100 TPY for several pollutants.
- b. The facility's PTE is greater than 10 TPY for any one HAP and greater than 25 TPY of all HAPs.
- c. This source is not located in a serious PM₁₀ nonattainment area.
- d. This facility is subject to NSPS requirements.
- e. This facility is subject to NESHAP requirements.
- f. This source is not a Title IV affected source, nor a solid waste combustion unit.
- g. This source is not an EPA designated Title V source.

Based on these facts, DEQ determined that Phillips 66 is subject to the Title V operating permit program.

III. BACT Determination

There is no BACT determination to be made regarding this permit action. All of the changes that were made with this action are administrative because they were made in previous actions. Please refer to prior MAQPs (#2619-28 to #2619-44) regarding relevant air quality analyses.

V. Emission Inventory

Pollutant	Project-Only Emissions Increase (tpy)	Project-Only Emissions Decrease (tpy)	PSD Significant Threshold (tpy)	PSD Significant? (Yes/No)
CO	90.11	-24.40	100	No
NO _x	52.30	-29.65	40	Yes
PM	PM, PM ₁₀ , PM _{2.5} already subject to PSD, MAQP #2619-38		25	Yes
PM ₁₀			15	Yes
PM _{2.5}			10	Yes
SO ₂	39.68	-0.28	40	No
VOC	29.80	-2.10	40	No
H ₂ S	0.90	0	10	No
Lead	0.0025	0	0.6	No

VI. Existing Air Quality

Phillips 66 is located at 401 South 23rd Street in Billings, Montana in the NW ¼ of Section 2, Township 1 South, Range 26 East, in Yellowstone County. The area is currently designated as attainment/unclassifiable for all National Ambient Air Quality Standards (NAAQS).

VII. Air Quality Impacts Analyses

There is no air quality analysis required regarding the current permit action. The permit action is administrative as it relates to past actions. Please refer to prior MAQPs (#2619-28 to #2619-44) regarding relevant air quality analyses.

VIII. Environmental Assessment

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



Phillips 66 Company

Final Environmental Assessment for Montana Air Quality Permit #2619-45

Air Quality Bureau

APPLICANT: Phillips 66 Company (Phillips 66)		
SITE NAME: Billings Petroleum Refinery		
PROPOSED PERMIT NUMBER: Montana Air Quality Permit (MAQP) #2619-45		
APPLICATION RECEIVED: September 5 th , 2023		
APPLICATION DEEMED COMPLETE: September 22 nd , 2023		
LOCATION: The legal address is NW ¹ / ₄ of Section 2, Township 1 South, Range 26 East, which is physically located at 401 South 23 rd Street, in Billings, MT 59101.		COUNTY: Yellowstone
PROPERTY OWNERSHIP:	FEDERAL ____ STATE ____ PRIVATE <u>X</u> __	
EA PREPARER:	Tim Gauthier	
EA Draft Date	EA Final Date	Permit Final Date
October 16 th , 2023	November 1 st , 2023	November 17 th , 2023

COMPLIANCE WITH THE MONTANA ENVIRONMENTAL POLICY ACT

The Montana Department of Environmental Quality (DEQ) prepared this Environmental Assessment (EA) in accordance with requirements of the Montana Environmental Policy Act (MEPA). An EA functions to determine the need to prepare an Environmental Impact Statement (EIS) through an initial evaluation and determination of the significance of impacts associated with the proposed action. However, an agency is required to prepare an EA to disclose potential impacts prior to reaching a final decision on the proposed actions covered by MEPA (ARM 17.4.602) and conducting an action of potentially issuing a permit to an applicant (ARM 17.4.603(1)). This document may disclose impacts over which DEQ has no regulatory authority.

COMPLIANCE WITH THE CLEAN AIR ACT OF MONTANA

The state law that regulates air quality permitting in Montana is the Clean Air Act of Montana (CAA), §§ 75-2-101, *et seq.*, Montana Code Annotated (MCA). DEQ may not approve a proposed action contained in an application for an air quality permit unless the project complies with the requirements set forth in the CAA and the administrative rules adopted thereunder, ARMs 17.8.101 *et. seq.* DEQ's potential approval of an air quality permit application does not relieve Phillips 66 from complying with any other applicable federal, state, or county laws, regulations, or ordinances. Phillips 66 is responsible for obtaining any other permits, licenses, or approvals (from DEQ or otherwise) that are required for any part of the proposed action. Any action DEQ takes at this time is limited to the pending air quality permit application currently before DEQ's AQB and the authority granted to DEQ under the Clean Air Act of Montana. This action is not indicative of any other action DEQ may take on any future (unsubmitted) applications made pursuant to any other authority (*e.g.* Montana's Water Protection Act). DEQ would decide whether to issue the pending air quality permit pursuant to the requirements of the CAA alone. DEQ may not withhold, deny, or impose conditions on the permit based on the information contained in this Environmental Assessment. § 75-1-201(4), MCA.

SUMMARY OF THE PROPOSED ACTION

All information included in the EA is derived from the permit application, discussions with the applicant, analysis of aerial photography, and other research tools including those provided by other agencies.

Phillips 66 has requested to modify their MAQP based on changes to the refinery under the Vacuum Improvement Project (VIP). VIP included improvements in crude unit distillation capabilities and wastewater treatment facilities, an increase in hydrogen production capabilities, and an expansion of the Jupiter Sulphur, LLC (Jupiter) sulfur recovery facilities at the existing refinery.

Table 1: Summary of Proposed Action

Summary of Proposed Action	
General Overview	<p>With this submittal, Phillips 66 is proposing to include two new NO_x and SO₂ emission limitations for two of the affected units affected by the VIP (<i>i.e.</i> Large Crude Unit Heater H-24 and Vacuum Furnace H-17). This submittal keeps VIP as a non-major modification for NO_x and SO₂ under the PSD program.</p> <p>In addition, Phillips 66 is requesting the following:</p> <ul style="list-style-type: none">• Revise the SO₂ emission limitation addressed in MAQP #2619-39 for the fluid catalytic cracking unit (FCCU). DEQ did not approve this portion of the application;• Clarify the SO₂ emission limitation addressed in MAQP #2619-32 for the Jupiter Sulfur Recovery Unit (SRU) Main Stack #2,

	<ul style="list-style-type: none"> • Removal of Compressor C-23 as well as its permit terms and conditions, • Clarify the applicability of certain new source performance standards (NSPS) to further streamline requirements for refinery operations.
Proposed Action Estimated Disturbance	
Disturbance	No land disturbance is required.
Proposed Action	
Duration	<p>Construction: Construction for the VIP project has already taken place.</p> <p>Operation Life: The refinery would be expected to remain operational as long as economic conditions are favorable.</p>
Construction Equipment	Construction for the VIP project has already taken place.
Personnel Onsite	No change is staff is necessary to accommodate the project.
Location and Analysis Area	<p>Location: The legal address is NW¼ of Section 2, Township 1 South, Range 26 East, which is physically located at 401 South 23rd Street, in Billings, MT 59101, just west of and across the river from Sacrifice Cliff.</p> <p>Analysis Area: The area being analyzed as part of this environmental review includes the immediate project area (Figure 1), as well as neighboring lands surrounding the analysis area, as reasonably appropriate for the impacts being considered.</p>
Air Quality	The Draft EA would be attached to the Preliminary Determination Air Quality Permit which would include all enforceable conditions for operation of the emitting units. Any revisions to the EA would be addressed and included in the Final EA attached to the Department's Decision.
Conditions Incorporated into the Proposed Action	The conditions developed in the Preliminary Determination of the MAQP.

Figure 1: Phillips 66 Company Refinery enclosed in the blue border:

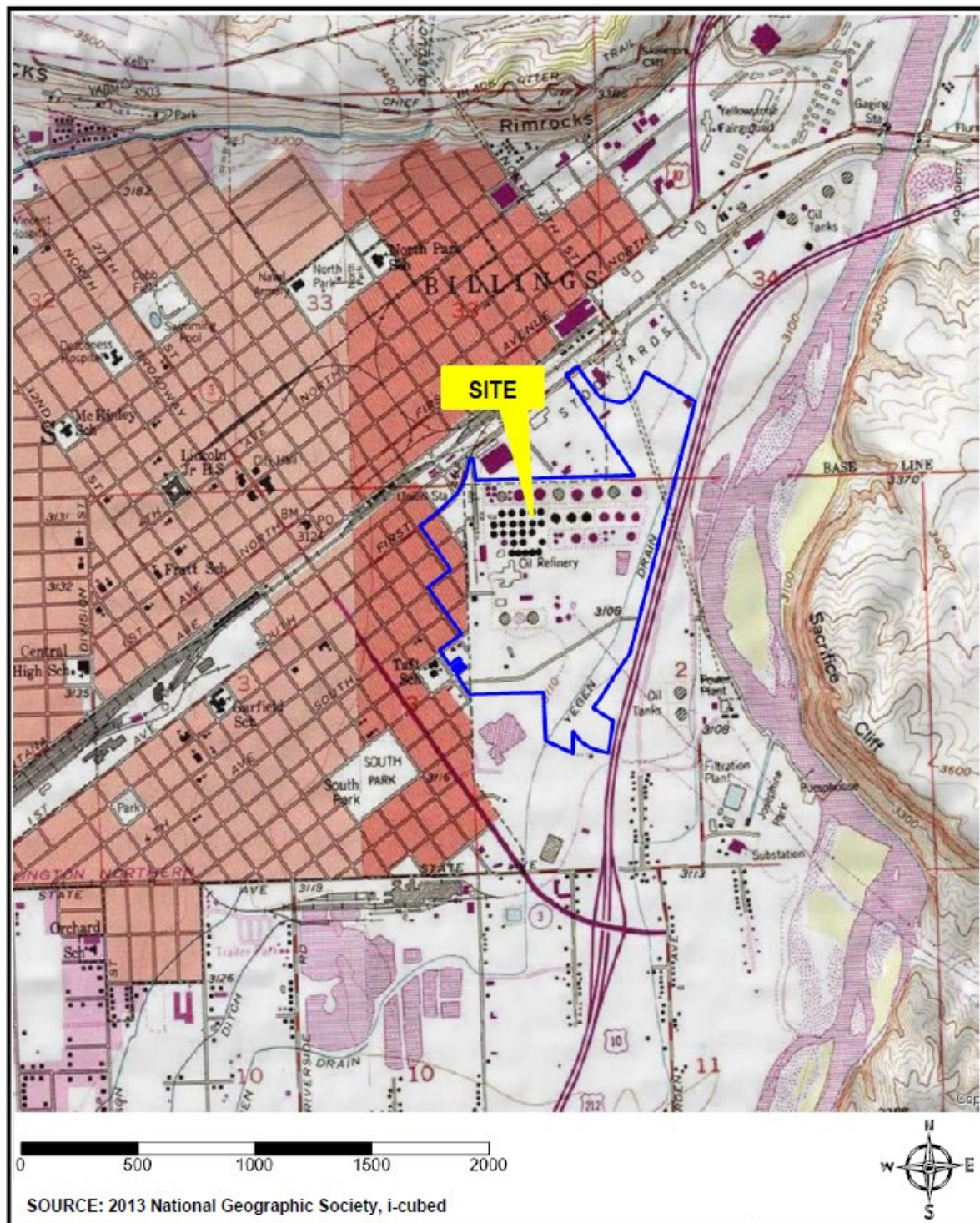


Figure 2: Phillips 66 Refinery, Green Arrow to FCCU



PURPOSE AND BENEFIT FOR PROPOSED ACTION

DEQ's purpose in conducting this environmental review is to act upon Phillips 66's air quality permit application No. 2619-45 for incorporation of VIP project revisions into the permit and other applicability updates. . The benefits of the proposed action, if approved, include: keeping the MAQP up-to-date, updating NO_x and SO₂ conditions, and changing NSPS requirements to allow the refinery operating flexibility. .

Authority to Phillips 66 for operation of the affected units would continue until the permit is revoked, either at the request of Phillips 66 or by DEQ because of non-compliance with the conditions within the air quality permit.

REGULATORY RESPONSIBILITIES

In accordance with ARM 17.4.609(3)(c), DEQ must list any federal, state, or local authorities that have concurrent or additional jurisdiction or environmental review responsibility for the proposed action and the permits, licenses, and other authorizations required. Phillips 66 must conduct its operations according to the terms of its permit, the CAA, §§ 75-2-101, *et seq.*, MCA, and ARMs 17.8.101, *et seq.*

Phillips 66 must cooperate fully with, and follow the directives of, any federal, state, or local entity that may have authority.

EVALUATION AND SUMMARY OF POTENTIAL IMPACTS TO THE PHYSICAL AND HUMAN ENVIRONMENT IN THE AREA AFFECTED BY THE PROPOSED ACTION:

The impact analysis will identify and evaluate direct and secondary impacts. Direct impacts are those that occur at the same time and place as the action that triggers the effect. Secondary impacts mean “a further impact to the human environment that may be stimulated or induced by or otherwise result from a direct impact of the action.” ARM 17.4.603(18). Where impacts are expected to occur, the impacts analysis estimates the duration and intensity of the impact.

The duration of an impact is quantified as follows:

- **Short-term:** Short-term impacts are defined as those impacts that would not last longer than the proposed operation of the site. In this case, indefinitely, or until authorization is revoked by DEQ or as requested by Phillips 66.
- **Long-term:** Long-term impacts are defined as impacts that would remain or occur following shutdown of the proposed facility.

The severity of an impact is measured using the following:

- **No Impact:** There would be no change from current conditions.
- **Negligible Impact:** An adverse or beneficial effect would occur but would be at the lowest levels of detection.
- **Minor Impact:** The effect would be noticeable but would be relatively small and would not affect the function or integrity of the resource.
- **Moderate Impact:** The effect would be easily identifiable and would change the function or integrity of the resource.
- **Major Impact:** The effect would alter the resource.

1. TOPOGRAPHY, GEOLOGY AND SOIL QUALITY, STABILITY AND MOISTURE:

The Vacuum Improvement Project (VIP) did not change the soil stability or geologic substructure at or near the project site. No unique geologic or physical features were disturbed. Additionally, the project did not result in a reduction of available acreage or productivity of any agricultural land; therefore, agricultural production was not affected by this project. As this update is administrative in nature, it would not provide for any new construction but only clarifies emission limits and applicable requirements.

Direct Impacts: No impact to topography, geology and soil quality, stability, or moisture would be expected.

Secondary Impacts: No impact to topography, geology and soil quality, stability, or moisture would be expected.

2. WATER QUALITY, QUANTITY, AND DISTRIBUTION:

The Phillips 66 Refinery is located adjacent to the Yellowstone River. The refinery operates under Montana Pollutant Discharge Elimination System (MPDES) permit #MT0000256, which was modified to include post-construction wastewater treatment configurations and discharge rates. The City of Billings Significant Industrial User Permit, #1-13, was modified to show post-construction wastewater treatment configuration and discharge rates. As this update is administrative in nature, it would not provide for any new construction but only clarifies emission limits and applicable requirements.

Direct Impacts: No more than minor impacts to water quality, quantity, and distribution would be expected, as the site's wastewater is actively regulated by permit.

Secondary Impacts: No more than minor impacts to water quality, quantity and distribution would be expected, as the site's wastewater is actively regulated by permit.

3. AIR QUALITY:

The VIP project resulted in emissions increases for CO, NO_x, SO₂, and VOC as depicted in Table 2 below. None of the increases put Phillips 66 above the PSD significant emission rates, including NO_x for which there were also adjustments for heaters/furnaces and project decreases that put the net emissions increase below 40 tpy.

Table 2: VIP Emissions Increases

Pollutant	Project-Only Emissions Increase (tpy)	Net Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	PSD Significant? (Yes/No)
CO	90.11	N/A	100	No
NO _x	52.30	39.82	40	No
SO ₂	39.68	N/A	40	No
VOC	29.80	N/A	40	No

As this update is administrative in nature, it would not provide for any new construction but only clarifies emission limits and applicable requirements.

Direct Impacts: Air pollution control equipment must be operated to provide the maximum air pollution control for which it is designed (ARM 17.8.752(2)), and in no case are emissions allowed to exceed those which would be allowed in the permit. The amount of emissions increases allowable from the project would be defined by permit and is demonstrated to not pose an unacceptable change in the area.

Air quality standards are regulated by the federal Clean Air Act, 42 U.S.C. 7401 *et seq.* and CAA, § 50-40-101 *et seq.* MCA, and are implemented and enforced by DEQ's AQB. Phillips 66 is required to comply with all applicable state and federal laws. No more than minor impacts to air quality would be expected..

Secondary Impacts: Emissions are to be restricted by this MAQP, and as presented above, the change in emissions would be expected to have only a minor impact to air quality. The area is currently achieving the ambient air quality standards. No more than minor secondary impacts to air quality would be expected..

4. VEGETATION COVER, QUANTITY AND QUALITY:

Petroleum refining has been conducted at this site for decades, and the first air quality permit for the site was issued in 1982. The site itself is a developed industrialized area. The proposed action would be located within the Refinery property boundaries, and does not require any construction. There are not any notable plant species present at the project site. As this update is administrative in nature, it would not provide for any new construction but only clarifies emission limits and applicable requirements. A picture of the site is noted below.

Figure 2: Aerial Photo



Direct Impacts: No impact would be expected, as no vegetation is within the project location.

Secondary Impacts: No impact would be expected as no vegetation is within the project location.

5. TERRESTRIAL, AVIAN AND AQUATIC LIFE AND HABITATS:

As described in Section 4 regarding vegetation, the area is represented by long existing industrial operations. Refinery operations and other nearby commercial and industrial operations creating noise, traffic, construction, air emissions, and other such disturbances have been present at the site locale for decades. No construction is expected as part of the current permit action. Negligible impacts from air emissions would be expected. Therefore, no significant impacts to terrestrial, avian, and aquatic life and habitats would be expected. As this update is administrative in nature, it would not provide for any new construction but only clarifies emission limits and applicable requirements.

Direct Impacts: No more than negligible impacts to terrestrial, avian and aquatic life and habitats would be expected, due to the long-term industrial nature of the site.

Secondary Impacts: No more than negligible impacts to terrestrial, avian and aquatic life and habitats would be expected.

6. UNIQUE, ENDANGERED, FRAGILE OR LIMITED ENVIRONMENTAL RESOURCES:

The Department contacted the Montana Natural Heritage Program, Natural Resource Information System (NRIS) to identify any unique endangered, fragile, or limited environmental resources in the area. In this case, the project area was defined by a three-mile radius around the latitude and longitude coordinates of the proposed location.

Species of concern (SOC) include: sauger, Yellowstone cutthroat trout, western milksnake, monarch, spotted bat, plains hog-nosed snake, snapping turtle, Lewis's woodpecker, veery, great blue heron, bald eagle, greater short-horned lizard, hoary bat, little brown myotis, spiny softshell, pinyon jay, long-eared myotis, Cassin's finch, loggerhead shrike, sage thrasher, greater sage-grouse, Brewer's sparrow, bractless hedge-hyssop, Sprague's pipit, swamp milkweed, bat roost (non-cave), burbot, yellow-billed cuckoo, broad-tailed hummingbird, eastern screech-owl, chimney swift, western spotted skunk, Americal white pelican, white-faced ibis, ovenbird, plumbeous vireo, North American porcupine, evening grosbeak, common poorwill, rufous hummingbird, northern leopard frog, black-tailed prairie dog, golden eagle, silver-haired bat, sharp-tailed grouse, black-and-white warbler, great plains toad, black-necked stilt, brook stickleback, American goshawk, brown creeper, Clark's nutcracker, hooded merganser, ferruginous hawk, Franklin's gull, thick-billed longspur, northern hawk owl, Caspian tern, common loon, Tennessee warbler, trumpeter swan, grizzly bear, Canada lynx, great gray owl, LeConte's sparrow, arctic grayling, black-billed cuckoo, Merriam's shrew, suckle cuckoo bumble bee, Berry's mountainsnail, dickcissel, pallid bat, long-legged myotis, dwarf shrew, eastern red bat, platte cinquefoil, double bladderpod, Barrow's goldeneye, Townsend's big-eared bat, Hayden's shrew, black-crowned night-heron, Cassin's kingbird, spotted joey-weed, long-billed curlew, eastern bluebird, small yellow lady's-slipper, green-tailed towhee, fringed myotis, Geyer's milkvetch, fleshy stitchwort, short-eared owl, and red knot.

The proposed action would be located at an existing facility, would not require additional ground disturbance or significant construction, would not be likely to result in measurable impacts to local ecosystems, and no endangered or fragile or limited environmental resource occurrences

were identified in the study area. Therefore, the Department has determined that the proposed action would not impact species of special concern or fragile or limited environmental resources. As this update is administrative in nature, it would not provide for any new construction but only clarifies emission limits and applicable requirements.

Direct Impacts: No more than negligible impacts to unique, endangered, fragile, or limited environmental resources would be expected.

Secondary Impacts: No more than negligible impacts to unique, endangered, fragile, or limited environmental resources would be expected.

7. HISTORICAL AND ARCHAEOLOGICAL SITES:

Information obtained from the Montana Cultural Resource Database under the State Historic Preservation Office (SHPO) on September 18th, 2023 indicates that the township, range, and section of the proposed project area contains both historical and archaeological resources. Sites that are classified as “undetermined” are considered for evaluation purposes, eligible to the National Register of Historic Places (NRHP). There are currently 19 sites identified within the broad search criteria (Table 3). Twelve of these sites are listed as undetermined or eligible for listing to the NRHP. Seven are listed as ineligible and thus removed from impact consideration. As this update is administrative in nature, it would not provide for any new construction but only clarifies emission limits and applicable requirements.

Table 3: Cultural Resources Identified in the General Project Area:

Site ID	T	R	Section	Description	Ownership	NRHP Status
24YL1536	1S	26E	2	Petroglyph	BLM	Eligible
24YL1537	1S	26E	2	Petroglyph	BLM	Eligible
24YL1601	1S	26E	2	Historic Irrigation	Private	Ineligible
24YL1608	1S	26E	2	Historic Industrial	Other	Eligible
24YL1609	1S	26E	2	Historic Industrial	Other	Eligible
24YL1896	1S	26E	2	Historic Cattle	BLM	Ineligible
24YL2072	1S	26E	2	Rock Cairn	BLM	Undetermined
24YL2074	1S	26E	2	Rock Cairn	BLM	Ineligible
24YL2075	1S	26E	2	Historic Inscription	BLM	Eligible
24YL2077	1S	26E	2	Historic Homestead	BLM	Ineligible
24YL2080	1S	26E	2	Historic Irrigation	BLM	Ineligible
24YL2081	1S	26E	2	Vision Quest Structure	BLM	Eligible
24YL2082	1S	26E	2	Petroglyph	BLM	Eligible
24YL2083	1S	26E	2	Historic Religion	BLM	Ineligible
24YL2084	1S	26E	2	Historic Inscription	BLM	Ineligible
24YL2085	1S	26E	2	Petroglyph	BLM	Eligible
24YL2185	1S	26E	2	Historic Residence	Private	Undetermined
24YL2186	1S	26E	2	Historic Residence	Private	Undetermined
24YL2187	1S	26E	2	Historic Residence	Private	Undetermined

Many of the petroleum refineries that are found in Montana would not be expected to qualify as an important historic resource. However, any site or structure that is 50 years or older qualifies as a cultural resource and merits accounting for. Many of these facilities have been operating since the 1920's to 1950's, placing them into the age range of "industrial archeology". Currently under state actions, there are no statutes that require the recording and preservation of such sites. However, the Montana Environmental Policy Act (MEPA) does require an evaluation and disclosure of potential impacts.

In conducting this disclosure, the facility may not be recorded as a site using standard cultural resource methodology. Since it was constructed in 1947, the facility is recognized as an "unevaluated" site and considered potentially eligible for nomination to the NRHP for potential impacts.

For facilities that qualify as a historic site but remain in operation today, it is expected that numerous changes to the facility have occurred over time. Replacement of parts and structures is seen as the natural evolution of such sites, and part of their history. However, these changes to industrial facilities are generally seen as being "consistent with the original nature of the facility's purpose" and are therefore not seen as a change that impacts the integrity of the site and can be assessed as having "no adverse impact".

No construction activities are necessary for the current action. None of the identified eligible or undetermined sites are within a quarter of a mile of the facility location; therefore, no physical impacts would be expected. The proposed action is consistent with the current and historic use of the facility.

Direct Impacts: No impact to the facility or any of the sites identified in Table 3 would be expected.

Secondary Impacts: No impact to nearby sensitive archeological sites would be expected.

8. SAGE GROUSE EXECUTIVE ORDER:

The project would not be in core, general, or connectivity sage grouse habitat, as designated by the Sage Grouse Habitat Conservation Program at: <http://sagegrouse.mt.gov>. As this update is administrative in nature, it would not provide for any new construction but only clarifies emission limits and applicable requirements.

Direct Impacts: No impact to the Sage Grouse Executive Order would be expected because the proposed action is not located within recognized Sage Grouse habitat.

Secondary Impacts: No impact to the Sage Grouse Executive Order would be expected because the proposed action is not located within recognized Sage Grouse habitat.

9. AESTHETICS:

Refinery operations and other nearby commercial and industrial operations creating noise, traffic, construction, air emissions, and other such disturbances have been present at the site locale for

decades. VIP occurred on land already used for industrial activities, and this land is in an area containing other commercial and industrial properties. Therefore, any impacts on the aesthetics of the nearby area would be minimal. As this update is administrative in nature, it would not provide for any new construction but only clarifies emission limits and applicable requirements.

Direct Impacts: Minor impact to aesthetics would be expected based on the equipment added by VIP.

Secondary Impacts: Minor impact to aesthetics would be expected based on the equipment added by VIP.

10. DEMANDS ON ENVIRONMENTAL RESOURCES OF LAND, WATER, AIR OR ENERGY:

The site is a long operating heavy industrial facility. The operation of the refinery generates fuel for consumers offsite as gasoline, diesel, and jet fuel, as well as other products and intermediates. As this update is administrative in nature, it would not provide for any new construction but only clarifies emission limits and applicable requirements.

Direct Impacts: Minor impact based on increase in electrical demand would be expected.

Secondary Impacts: Minor impact based on increase in electrical demand would be expected.

11. IMPACTS ON OTHER ENVIRONMENTAL RESOURCES:

The site is a long operating industrial site with surroundings including other commercial and industrial properties. No other environmental resources have been identified in the area.

Direct Impacts: No impact to other environmental resources would be expected.

Secondary Impacts: No impact to other environmental resources would be expected.

12. HUMAN HEALTH AND SAFETY:

The applicant would be required to adhere to all applicable state and federal safety laws. The access to the public would continue to be restricted to this property. The Phillips 66 Billings Refinery submits that they are an OSHA VPP Star facility.

Direct Impacts: No more than minor impacts to human health and safety would be expected as a result of this project action. The MAQP would provide limitations and restrictions on allowable emissions, and the project is demonstrated to not cause or contribute to an exceedance of an ambient air quality standard. Ambient air quality standards are designed to protect public health.

Secondary Impacts: No more than minor secondary impacts to human health and safety would be expected as a result of the proposed action.

13. INDUSTRIAL, COMMERCIAL AND AGRICULTURAL ACTIVITIES AND PRODUCTION:

The site is currently zoned heavy industrial due to the refinery operation, and other adjacent industrial and commercial properties are present. There is no agricultural activity at the site.

Direct Impacts: The proposed action would not change the amount of land associated with the refinery. No more than negligible impacts from emissions would be expected. No impact on the industrial, commercial, and agricultural activities and production in the area.

Secondary Impacts: No impact to industrial, commercial, and agricultural activities and production would be expected as a result of the proposed action.

14. QUANTITY AND DISTRIBUTION OF EMPLOYMENT:

No change in the number of employees at the site would be expected as a result of the project. Resources required for this project are already available.

Direct Impacts: No impact on the overall distribution of employment.

Secondary Impacts: No impact would be expected on long term employment from the proposed action.

15. LOCAL AND STATE TAX BASE AND TAX REVENUES:

The proposed action would be expected to have minor, if any, impacts on the local and state tax base and tax revenue, as the project involves existing equipment and existing operations.

Direct Impacts: Minor impact would be expected on the tax base and revenue as a result of the proposed action.

Secondary Impacts: Minor impact to local and state tax base and tax revenues would be anticipated as a result of the proposed action.

16. DEMAND FOR GOVERNMENT SERVICES:

The proposed action requires application, permitting, and associated compliance follow-up. The site currently is noted as a 'mega source' for purposes of describing the compliance burden on air quality regulators. The project would not pose any significant change in government services needs. Compliance review and assistance oversight by DEQ AQB would be conducted in concert with other area activity when in the vicinity.

Direct Impacts: Minor impact on demand for government services, mainly through oversight by DEQ AQB.

Secondary Impacts: No impact would be anticipated on government services with the proposed action.

17. LOCALLY ADOPTED ENVIRONMENTAL PLANS AND GOALS:

DEQ is not aware of any locally adopted environmental plans and goals that the current project would impact. Notification regarding this project was communicated to local and county officials.

Direct Impacts: No impact on locally adopted environmental plans and goals.

Secondary Impacts: No impact on locally adopted environmental plans and goals.

18. ACCESS TO AND QUALITY OF RECREATIONAL AND WILDERNESS ACTIVITIES:

The current site of the proposed action is in an area of long industrial use. Recreation opportunities may exist in an area located east of the facility, across the river, on what is known as ‘sacrifice cliff’, but would not be expected to be significantly affected by the project. Noise, traffic, and emissions are associated with normal operation.

Direct Impacts: No impact to the access to wilderness activities as none are in the immediate vicinity of the proposed action and no change to noise or traffic is expected.

Secondary Impacts: No impact to access and quality of recreational and wilderness activities would be anticipated as a result of the proposed action.

19. DENSITY AND DISTRIBUTION OF POPULATION AND HOUSING:

The proposed project would not add to the population or require additional housing. No changes to the number of employees would be expected as a result of the project. No new housing would be expected needed as a result of the current project.

Direct Impacts: No impact to density and distribution of population and housing would be anticipated.

Secondary Impacts: No impact to density and distribution of population and housing would be anticipated as a result of the proposed action.

20. SOCIAL STRUCTURES AND MORES:

The proposed project takes place within the boundaries of the current refinery property. No new employment would be expected. The proposed action is located on an existing industrial site and no disruption of native or traditional lifestyles would be expected.

Direct Impacts: No impact to social structure and mores would be anticipated.

Secondary Impacts: No impact to social structures and mores would be anticipated as a result of the proposed project.

21. CULTURAL UNIQUENESS AND DIVERSITY:

DEQ is not aware of any unique qualities of the area that would be affected by the proposed action on this existing refinery facility.

Direct Impacts: No impact to cultural uniqueness and diversity would be anticipated from this project.

Secondary Impacts: No impact to cultural uniqueness and diversity would be anticipated as a result of the proposed project.

22. PRIVATE PROPERTY IMPACTS:

The proposed action would take place on privately-owned land. The analysis below in response to the Private Property Assessment Act indicates no impact. DEQ does not plan to deny the application or impose conditions that would restrict the regulated person's use of private property so as to constitute a taking. Further, if the application is complete, DEQ must take action on the permit pursuant to § 75-2-218(2), MCA. Therefore, DEQ does not have discretion to take the action in another way that would have less impact on private property—its action is bound by a statute.

There are private residences in the area of the proposed action. The current action does not propose any change to current property boundaries.

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

YES	NO	
		necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

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

23. OTHER APPROPRIATE SOCIAL AND ECONOMIC CIRCUMSTANCES:

Due to the nature of the proposed action, no further direct or secondary impacts would be anticipated from this project.

24. CLIMATE CHANGE-RELATED LITIGATION IN MONTANA

DEQ is aware of the recent district court opinion in *Held v. State*, ruling the statutory prohibition on including greenhouse gas analyses in MEPA reviews unconstitutional.¹ That decision is being appealed to the Montana Supreme Court and final resolution is yet unsettled. While litigation is ongoing, and consistent with the court order, DEQ has started a process to assess and improve our environmental review processes, including consideration of future climate impact analyses.

¹ *Held v. State*, No. CDV-2020-307 (Mont. 1st Jud. Dist. Ct. Aug. 14, 2023).

ADDITIONAL ALTERNATIVES CONSIDERED:

No Action Alternative: In addition to the analysis above for the proposed action, DEQ is considering a “no action” alternative. The “no action” alternative would deny the approval of the proposed action. The applicant would lack the authority to conduct the proposed activity. Any potential impacts that would result from the proposed action would not occur. The no action alternative forms the baseline from which the impacts of the proposed action can be measured.

Other Ways to Accomplish the Action: The current permitting action is administrative in nature. If the action is not approved as presented, the site would have to pursue a PSD evaluation for NO_x. Additionally, their NSPS applicability may not accurately reflect their current operation.

If the applicant demonstrates compliance with all applicable rules and regulations as required for approval, the “no action” alternative would not be appropriate. Pursuant to, § 75-1-201(4)(a), (MCA) DEQ “may not withhold, deny, or impose conditions on any permit or other authority to act based on” an environmental assessment.

CUMULATIVE IMPACTS:

Cumulative impacts are the collective impacts on the human environment within the borders of the proposed action when considered in conjunction with other past and present actions related to the proposed action by location and generic type. Related future actions must also be

considered when these actions are under concurrent consideration by any state agency through preimpact statement studies, separate impact statement evaluation, or permit processing procedures.

The current MAQP action would not itself result in any more than minor impacts to the considerations made above and would not elevate the level of impacts in conjunction with past or present related actions.

PUBLIC INVOLVEMENT:

Scoping for this proposed action consisted of internal efforts to identify substantive issues and/or concerns related to the proposed action. Internal scoping consisted of internal review of the EA document by DEQ Air Permitting staff.

Internal efforts also included the following queries:

- Montana State Historic Preservation Office
- Montana DEQ Cultural Resources Officer
- Montana Natural Heritage Program
- Montana Cadastral Mapping Program

A thirty-day public comment period occurred along with the Preliminary Determination on MAQP #2619-45, and the permit and EA was posted to the DEQ website.

OTHER GOVERNMENTAL AGENCIES WITH JURISDICTION:

The proposed action would be fully located on privately-owned land. All applicable local, state, and federal rules must be adhered to, which, at some level, may also include other local, state, federal, or tribal agency jurisdiction. Other Governmental Agencies which may have overlapping or sole jurisdiction include but may not be limited to: City of Billings, Yellowstone County, the Occupational Safety and Health Administration, DEQ AQB, DEQ Waste Management Bureau, and DEQ Water Protection Bureau.

NEED FOR FURTHER ANALYSIS AND SIGNIFICANCE OF POTENTIAL IMPACTS

Under ARM 17.4.608, DEQ is required to determine the significance of impacts associated with the proposed action. This determination is the basis for the agency's decision concerning the need to prepare an environmental impact statement and also refers to DEQ's evaluation of individual and cumulative impacts. DEQ is required to consider the following criteria in determining the significance of each impact on the quality of the human environment:

1. The severity, duration, geographic extent, and frequency of the occurrence of the impact.

“Severity” is analyzed as the density of the potential impact while “extent” is described as the area where the impact is likely to occur. An example could be that a project may propagate ten noxious weeds on a surface area of 1 square foot. In this case, the impact may be a high severity over a low extent. If those ten noxious weeds were located over ten acres there may be a low

severity over a larger extent.

“Duration” is analyzed as the time period in which the impact may occur while “frequency” is analyzed as how often the impact may occur. For example, an operation that occurs throughout the night may have impacts associated with lighting that occur every night (frequency) over the course of the one season project (duration).

2. The probability that the impact will occur if the proposed action occurs; or conversely, reasonable assurance in keeping with the potential severity of an impact that the impact will not occur.
3. Growth-inducing or growth-inhibiting aspects of the impact, including the relationship or contribution of the impact to cumulative impacts.
4. The quantity and quality of each environmental resource or value that would be affected, including the uniqueness and fragility of those resources and values.
5. The importance to the state and to society of each environmental resource or value that would be affected.
6. Any precedent that would be set as a result of an impact of the proposed action that would commit the DEQ to future actions with significant impacts or a decision in principle about such future actions.
7. Potential conflict with local, state, or federal laws, requirements, or formal plans.

The significance determination is made by giving weight to these criteria in their totality. For example, impacts with moderate or major severity may be determined to be not significant if the duration of the impacts is considered to be short-term. As another example, however, moderate or major impacts of short-term duration may be considered to be significant if the quantity and quality of the resource is limited and/or the resource is considered to be unique or fragile. As a final example, moderate or major impacts to a resource may be determined to be not significant if the quantity of that resource is high or the quality of the resource is not unique or fragile.

Preparation of an EA is the appropriate level of environmental review under MEPA if statutory requirements do not allow sufficient time for an agency to prepare an environmental impact statement, pursuant to ARM 17.4.607. An agency determines whether sufficient time is available to prepare an environmental impact statement by comparing statutory requirements that establish when the agency must make its decision on the proposed action with the time required to obtain public review of an environmental impact statement plus a reasonable period to prepare a draft environmental review and, if required, a final environmental impact statement.

SIGNIFICANCE DETERMINATION

The severity, geographic extent, and frequency of the occurrence of the primary, secondary, and cumulative impacts associated with the proposed action would be limited. These impacts would be allowed indefinitely.

DEQ has not identified any significant impacts associated with the proposed action for any environmental resource. Approving Phillips 66's air quality permit application would not set precedent that commits DEQ to future actions with significant impacts or a decision in principle about such future actions.

DEQ's issuance of a modified MAQP to Phillips 66 for this proposed operation also does not set a precedent for DEQ's review of other applications, including the level of environmental review. A decision on the appropriate level of environmental review is made based on case-specific considerations of the criteria set forth in ARM 17.4.608.

DEQ does not believe that the proposed action has any growth-inducing or growth-inhibiting aspects or that it conflicts with any local, state, or federal laws, requirements, or formal plans. Based on a consideration of the criteria set forth in ARM 17.4.608, the proposed state action is not predicted to significantly impact the quality of the human environment. Therefore, at this time, preparation of an EA is determined to be the appropriate level of environmental review under MEPA.

Environmental Assessment and Significance Determination Prepared By:

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Name	Title