



January 6, 2020

Steve Torpey  
Phillips 66 Company  
Billings Refinery  
PO Box 30198  
Billings, MT 59107-0198

Dear Mr. Torpey:

Montana Air Quality Permit #2619-39 is deemed final as of January 6, 2021, by the Department of Environmental Quality (Department). This permit is for Phillips 66 Company's Billings Refinery. All conditions of the Department's Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

For the Department,

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 "Shawn Juers".

Shawn Juers  
Air Quality Engineer  
Air Quality Bureau  
(406) 444-2049

JM:SJ  
Enclosure

Montana Department of Environmental Quality  
Air, Energy & Mining Division

Montana Air Quality Permit #2619-39

Phillips 66 Company  
Billings Refinery  
P.O. Box 30198  
NW<sup>1</sup>/<sub>4</sub> of Section 2, Township 1 South, Range 26 East, Yellowstone County

1/6/2021



## MONTANA AIR QUALITY PERMIT

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

MAQP: #2619-39  
Application Complete: 10/23/2020  
Preliminary Determination: 11/9/2020  
Department's Decision: 12/21/2020  
Permit Final: 1/6/2021  
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 23<sup>rd</sup> Street, Billings, Montana, in the NW<sup>1</sup>/<sub>4</sub> 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 7<sup>th</sup> 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 23, 2020, the Montana Department of Environmental Quality – Air Quality Bureau (Department) received from Phillips 66 an MAQP application for significant changes to the refinery. An addendum to the application was received on October 23, 2020. The application triggers the Prevention of Significant Deterioration (PSD) program requirements of ARM 17.8 Subchapter 8 for oxides of nitrogen (NO<sub>x</sub>), particulate matter with an aerodynamic diameter of 2.5 microns and less (PM<sub>2.5</sub>), particulate matter with an aerodynamic diameter of 10 microns or less (PM<sub>10</sub>), and greenhouse gases (GHGs). The project also triggers PSD for ozone based on NO<sub>x</sub>.

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 (No. 3 H<sub>2</sub> Plant), 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.

## SECTION II: Conditions and Limitations

### A. Applicable Requirements

1. Phillips 66 shall comply with all applicable requirements of ARM 17.8.340, which reference 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, SO<sub>2</sub>, 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 H<sub>2</sub> 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
- iv. T-104\*

\* *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 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. The affected tanks include, but are not limited to, the following:

Tank ID

- i. T-35
- ii. T-36 (Currently out of service)
- iii. T-72
- iv. T-107\*
- v. T-110
- vi. T-0851 (No.5 HDS Feed Storage Tank)
- vii. T-1102 (Crude Oil Storage Tank)
- viii. T-2909 (LSG Tank)
- ix. T-3201\* (Currently out of service)

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

- g. Subpart UU - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture shall apply to, but not be limited to, asphalt storage tank T-3201 and any other applicable storage tanks that commenced construction or modification after May 26, 1981. Asphalt storage tank T-3201 shall comply with the standards in 40 CFR 60.472(c).
- h. Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries 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
- i. Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the following compressors which are in hydrogen service:
  - i. C-8401, No. 4 HDS Makeup/Recycle H<sub>2</sub> Compressor
  - ii. C-7401, H<sub>2</sub> Makeup/Reformer H<sub>2</sub> Compressor
  - iii. C-9401, H<sub>2</sub> Plant Feed Gas Compressor
  - iv. C-9501, Makeup/Recycle Gas Compressor
  - v. C-9701, Feed Gas Compressor
- j. Subpart GGGa - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the C-8402, No. 4 HDS Makeup/Recycle Compressor, which is in hydrogen service.
- k. 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:
  - a. Delayed Coker Unit
  - b. Cryogenic Unit
  - c. Hydrogen Membrane Unit
  - d. Gasoline Merox Unit
  - e. Crude Units
  - f. Gas Oil Hydrotreater Unit (consisting of a reaction section, fractionation section, and an amine treating section)
  - g. No. 1 H<sub>2</sub> Unit (22.0-million standard cubic feet per day (MMscfd) hydrogen plant feed system)
  - h. 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)
  - i. Alkylation Unit Depropanizer Project
  - j. #3 Sour Water Stripper (SWS) Unit

- k. Fugitive components associated with boilers #B-5 and #B-6
  - l. Fugitive components associated with the No.2 H<sub>2</sub> Unit and the No.5 HDS Unit
  - m. HPU
  - n. FCCU
  - o. No. 3 H<sub>2</sub> Plant, and
  - p. Any other applicable equipment constructed or modified after November 7, 2006
1. 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. Corrugated Plate Interceptor (CPI) separators
  - iv. Gas oil hydrotreater oily water sewer drain system
  - v. No. 1 H<sub>2</sub> Plant (22.0-MMscfd H<sub>2</sub> plant)
  - vi. C-23 compressor station oily water sewer drain system
  - vii. Alkylation Unit Butane Defluorinator oily water sewer drain system
  - viii. Alkylation Unit Depropanizer oily water sewer drain system
  - ix. #3 SWS Unit oily water sewer drain system
  - x. South Tank Farm oily water sewer drain system
  - xi. Tank T-4523 (wastewater surge tank)
  - xii. API Separators, including the slop oil vessel T-4526 and Sludge Hopper T-4527.
  - xiii. No. 2 H<sub>2</sub> Plant and the No. 5 HDS Unit new individual oily water drain system
  - xiv. No. 3 H<sub>2</sub> Plant, and
  - xv. Any other applicable equipment, for requirements not overridden by 40 CFR 63 Subpart CC

- m. 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 Backup Emergency Generator for the HDS Flare Drum Pump.
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 H<sub>2</sub> 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:
    - Proto Gas Tanks #2901 - #2907
    - 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 EEEE - National Emission Standards for Hazardous Air Pollutants:
- Organic Liquids Distribution (Non-Gasoline) shall apply to, but not be limited to, Proto Gas storage tanks.
- g. 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 Backup Emergency Generator for the HDS Flare Drum Pump, and the Boiler House Backup Air Compressor engine.
- h. 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.

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 SO<sub>2</sub> 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<sub>x</sub> reducing catalyst additive, and SO<sub>2</sub> reducing catalyst additive in the FCCU catalyst regenerator, hydrotreating of the feed to the FCCU, as well as CO, NO<sub>x</sub>, SO<sub>2</sub>, and O<sub>2</sub> CEMS, to control CO, NO<sub>x</sub>, and SO<sub>2</sub> 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 4<sup>th</sup> 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. The C-23 compressor station shall have a VOC monitoring and maintenance program instituted as described in 40 CFR 60.482-2, 40 CFR 60.482-4 thru 10, 40 CFR 60.483-1 and 2, 40 CFR 60.485, 40 CFR 60.486 (b-k), and 40 CFR 60.486 (c-e). If monitoring or scheduled inspections indicate failure or leakage of the compressor seal system, then the seals shall be repaired as soon as practicable (but not later than 15 calendar days after it is detected), except as provided in 40 CFR 60.482-9 (ARM 17.8.752).
8. 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).
9. The large crude unit heater (H-24), recycle hydrogen heater (H-8401), fractionator feed heater (H-8402), No. 1 H<sub>2</sub> plant reformer heater (H-9401), and No. 2 H<sub>2</sub> Plant Reformer Heater (H-9701) shall be equipped with Ultra Low NO<sub>x</sub> Burners (ULNB) (ARM 17.8.752).

10. The Claus SRU Incinerator (F-304) shall be equipped with LNB (ARM 17.8.752 and ARM 17.8.819).
11. The coker heater (H-3901) shall be equipped with LNB.<sup>1</sup>
12. Boilers #B-5 and #B-6 shall be equipped with ULNB (ARM 17.8.752, ARM 17.8.819).
13. 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).
14. 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).
15. 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 the Department 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).
16. 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).
17. 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).
18. 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).
19. The Claus SRU shall be equipped with a TGTU (ARM 17.8.752 and ARM 17.8.819).
20. SRU #2 shall be considered subject to 40 CFR 60 Subpart Ja conditions as a modified unit (ARM 17.8.749).

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<sup>1</sup> The low NO<sub>x</sub> burners for the coker heater are a requirement of the coker Permit #2619 issued April 19, 1990.

21. SRU #3 shall be equipped with an oxidation tail gas scrubber process (ARM 17.8.752).
22. 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).
23. 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 a 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 Flare<sup>2</sup>
    - i. SO<sub>2</sub> Emissions - 25.00 lbs/hr, 0.30 tons/day.
    - ii. Hydrogen Sulfide (H<sub>2</sub>S) 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 SO<sub>2</sub> 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. PM<sub>10</sub> (filterable + condensable): 4.0 lb/hr (ARM 17.8.749)
  - c. PM<sub>2.5</sub> (filterable + condensable): 4.0 lb/hr (ARM 17.8.749)
  - d. SO<sub>2</sub>: 167 ppmvd at 0% O<sub>2</sub> 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<sub>x</sub>: 14.84 lb/hr (ARM 17.8.749, ARM 17.8.752, ARM 17.8.819)

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

- 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. PM<sub>10</sub> (filterable + condensable): 4.0 lb/hr (ARM 17.8.749)
  - c. PM<sub>2.5</sub> (filterable + condensable): 4.0 lb/hr (ARM 17.8.749)
  - d. SO<sub>2</sub>: 167 ppmvd at 3% O<sub>2</sub> 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)
  - f. NO<sub>x</sub>: 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. SO<sub>2</sub>: 50 tons per year on a 12-month rolling sum basis
  - b. NO<sub>x</sub>: 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. Upon startup of the FCCU following the modifications permitted in MAQP #2619-39, SO<sub>2</sub> 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. Upon startup of the FCCU following the modifications permitted in MAQP #2619-39, SO<sub>2</sub> emissions shall not exceed 26.32 tons per year as determined monthly on a rolling 12-month sum basis.
  - c. Until modifications as permitted in MAQP #2619-39, SO<sub>2</sub> emissions shall not exceed 328.8 lbs/hr, rolling 24-hour average; 3.945 ton/day; 48.86 TPY.
  - d. SO<sub>2</sub> emissions from the FCCU shall not exceed 25 ppmvd at 0% O<sub>2</sub> based on a rolling 365-day average, as well as 50 ppmvd at 0% O<sub>2</sub> based on a rolling 7-day average. SO<sub>2</sub> 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 SO<sub>2</sub> emission limit, provided that Phillips 66 implements good air pollution control practices to minimize SO<sub>2</sub> emissions. The 7-day SO<sub>2</sub> 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 SO<sub>2</sub> 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 SO<sub>2</sub> 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).

- e. SO<sub>2</sub> 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).
- f. CO emissions shall not exceed 150 ppmvd at 0% O<sub>2</sub> 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).
- g. CO emissions shall not exceed 500 ppmvd at 0% O<sub>2</sub> 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).
- h. After modifications as permitted in MAQP #2619-39, CO emissions shall not exceed 106.35 tons per year on a rolling 12 month sum basis (ARM 17.8.749).
- i. NO<sub>x</sub> emissions shall not exceed 49.2 ppmvd corrected to 0% O<sub>2</sub>, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O<sub>2</sub>, on a rolling 7-day average. NO<sub>x</sub> 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<sub>x</sub> emission limit, provided that Phillips 66 implements good air pollution control practices to minimize NO<sub>x</sub> emissions. The 7-day NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> 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).

- j. After modifications as permitted in MAQP #2619-39, NO<sub>x</sub> emissions shall not exceed 72.09 tons per year on a rolling 12-month sum basis (ARM 17.8.749).
- k. 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)
- l. Upon startup of the FCCU following modifications permitted in MAQP #2619-39, PM<sub>10</sub> and PM<sub>2.5</sub> emissions, including condensable emissions, from the FCCU shall not exceed 47.35 tons per year on a rolling 12-month sum basis.
- m. 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 H<sub>2</sub>S 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 H<sub>2</sub> Plant Reformer Heater (H-9401), No. 2 H<sub>2</sub> Plant Reformer Heater (H-9701), and No. 3 H<sub>2</sub> Plant Heater shall be sulfur free (ARM 17.8.752).
- d. The No. 1 H<sub>2</sub> Unit Reformer Heater (H-9401) and No. 2 H<sub>2</sub> 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 H<sub>2</sub> 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. Combined SO<sub>2</sub> 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 3, H-2;
  - iii. Emission Point 4, H-4;
  - iv. Emission Point 5, H-5;
  - v. Emission Point 7, H-10 – No. 2 HDS;
  - vi. Emission Point 8, H-11 – No. 2 HDS Debutanizer Reboiler;
  - vii. Emission Point 9, H-12 – No. 2 HDS Main Frac. Reboiler;
  - viii. Emission Point 10, H-13 – Catalytic Reforming Unit #2;
  - ix. Emission Point 11, H-14 – Catalytic Reforming Unit #2;
  - x. Emission Point 12, H-15;
  - xi. Emission Point 13, H-16 – Saturated Gas Stabilizer Reboiler and PB Merox Disulfide Offgas;
  - xii. Emission Point 14, H-17;
  - xiii. Emission Point 15, H-18;
  - xiv. Emission Point 16, H-19;
  - xv. Emission Point 17, H-20;
  - xvi. Emission Point 18, H-21;
  - xvii. Emission Point 20, H-23 – Catalytic Reforming Unit #2;
  - xviii. Emission Point 21, H-24;
  - xix. Emission Point 6, H-3901 – Coker Heater;
  - xx. Emission Point 28, H-8401 – Recycle Hydrogen Heater;
  - xxi. Emission Point 29, H-8402 – Fractionator Feed Heater.
- g. 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).
- h. 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 H<sub>2</sub> Plant Reformer Heater (H-9701), Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, No. 1 H<sub>2</sub> Plant Reformer Heater (H-9401), and No. 3 H<sub>2</sub> Plant Heater (H-8501) shall each not exceed 20% averaged over 6 consecutive minutes (ARM 17.8.304).
- i. Emissions from the Small Crude Unit Heater (H-1) (ARM 17.8.752), Large Crude Unit Heater (H-24) (ARM 17.8.752), and Vaccum

Furnace (H-17) (ARM 17.8.749), shall not exhibit an opacity of 10% or greater averaged over 6 consecutive minutes.

- j. PM<sub>10</sub> 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 H<sub>2</sub> Plant Reformer Heater H-8501 shall not exceed 0.0031 pounds per million british thermal units (lb/MMBtu) on a HHV basis (ARM 17.8.749).
- k. PM<sub>2.5</sub> 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 H<sub>2</sub> Plant Reformer Heater H-8501 shall not exceed 0.0021 lb/MMBtu on a HHV basis (ARM 17.8.749).
- l. Emissions from the Small Crude Unit Heater (H-1) shall not exceed:
  - i. NO<sub>x</sub>: 0.030 lb/MMBtu on a higher heating value (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).
- m. Emissions from the Large Crude Unit Heater (H-24) shall not exceed:
  - i. NO<sub>x</sub>: 0.040 lb/MMBtu on a HHV, 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).
- n. Emissions from the Vacuum Furnace (H-17) shall not exceed:
  - i. NO<sub>x</sub>: 0.030 lb/MMBtu on HHV, 30-day rolling average basis, determined daily. (ARM 17.8.752)
- o. Emissions from the No. 1 H<sub>2</sub> Unit Reformer Heater (H-9401) shall not exceed:
  - i. NO<sub>x</sub>: 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).
- p. Emissions from the No. 5 HDS Charge Heater (H-9501) shall not exceed:
- i. NO<sub>x</sub>: 0.03 pounds per million British thermal units (lb/MMBtu) on a higher heating value (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).
- q. Emissions from the No. 5 HDS Stabilizer Reboiler Heater (H-9502) shall not exceed:
- i. NO<sub>x</sub>: 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).
- r. Emissions from the No. 3 H<sub>2</sub> Plant Reformer Heater H-8501 shall not exceed:
- i. NO<sub>x</sub>: 35 ppmvd, corrected to 0% O<sub>2</sub>, determined daily on a 30-day rolling average basis (ARM 17.8.752, ARM 17.8.819). Compliance shall be monitored via NO<sub>x</sub> 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).
- s. Emissions from the No. 2 H<sub>2</sub> Plant Reformer Heater (H-9701) shall not exceed:
- i. NO<sub>x</sub>: 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).
- t. Emissions from the No. 1 H<sub>2</sub> Plant Reformer Heater (H-9401) shall not exceed:
  - i. CO: 0.025 lb/MMBtu (ARM 17.8.752).
  - u. NO<sub>x</sub> emissions from the Coker Heater (H-3901) shall not exceed 0.04 lb/MMBtu on a HHV basis and 21.80 ton per year on a rolling 12-month total basis (ARM 17.8.749).
  - v. NO<sub>x</sub> 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) and 1.33 tons per year, on a rolling 12-month basis (ARM 17.8.749) .
  - w. NO<sub>x</sub> 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), and 3.91 tons per year on a rolling 12-month basis (ARM 17.8.749).
  - x. NO<sub>x</sub> emissions from the No. 1 H<sub>2</sub> Plant Reformer Heater (H-9401) shall not exceed 0.042 lb/MMBtu and 11.05 lb/hr(ARM 17.8.752, ARM 17.8.749).
  - y. PM<sub>10</sub> and PM<sub>2.5</sub> emissions from the No. 1 H<sub>2</sub> Plant Reformer Heater (H-9401) and No. 2 H<sub>2</sub> Plant Reformer Heater (H-9701) shall not exceed 0.0075 lb/MMBtu (ARM 17.8.752 and ARM 17.8.819).
- e. Main Boilerhouse Stack
  - i. SO<sub>2</sub> 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)
  - ii. SO<sub>2</sub> Emissions shall not exceed: 300 TPY from fuel oil combustion, based on a rolling 365-day average as determined by the existing SO<sub>2</sub> Continuous Emissions Monitoring System (CEMS) or replacement SO<sub>2</sub> CEMS subsequently installed and certified (ARM 17.8.749).
  - iii. H<sub>2</sub>S content of fuel gas burned shall not exceed 0.10 gr/dscf, rolling 3-hr average.
  - iv. H<sub>2</sub>S 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).
  - v. 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).

- vi. NO<sub>x</sub> 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<sub>x</sub> and O<sub>2</sub> CEMS subsequently installed and certified (ARM 17.8.752).
- vii. CO emissions from boilers #B-5 and #B-6 shall each not exceed 0.04 lb/MMBtu (ARM 17.8.752).
- viii. 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).

c. 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).

d. PMA Storage Tank Vent (T-3201)

Opacity shall not exceed 0%, except for one consecutive 15-minute period in any 24-hour period when the transfer lines are being blown clear (40 CFR 60.472(c)).

e. Total SO<sub>2</sub> emissions for refinery and sulfur recovery facilities

Total SO<sub>2</sub> 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).

- 2. 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).
- 3. 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<sub>x</sub> 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% CO<sub>2</sub> (ARM 17.8.749).

4. Refinery Main Plant Relief Flare Stack

- a. The Main Refinery Plant Flare shall not burn any fuel gas that contains H<sub>2</sub>S 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).

5. Jupiter Flare

- a. The Jupiter Flare shall not burn any fuel gas that contains H<sub>2</sub>S 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).

- 6. 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)

- 7. 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 (μS/cm) at 25 degrees Celcius (ARM 17.8.749).

- 8. Phillips 66 shall permanently remove from current service the Desalter Breaker Tanks (T-4510 and T-4511) (ARM 17.8.749).

9. 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).

10. 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 Backup Emergency Generator for the HDS Flare Drum Pump shall not have a capacity exceeding 300 hp and shall have an EPA certification of Tier 3 or higher (ARM 17.8.749).
- c. The Backup Emergency Generator for the HDS Flare Drum Pump shall not exceed 1,000 hours of operation in any 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 GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries.
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 EEEEE, NESHAPs for Organic Liquids Distribution (Non-Gasoline).

E. Emission Testing and Monitoring

1. Phillips 66 shall monitor the FCCU Catalyst Regenerator for compliance with PM<sub>10</sub> and PM<sub>2.5</sub> emissions limits (including condensables) set in MAQP #2619-39 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 PM<sub>10</sub> and PM<sub>2.5</sub> (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 the Department. 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 the Department. 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 PM<sub>10</sub> (including condensables) and PM<sub>2.5</sub> (including condensables) are reported.
  - iv. Compliance with the FCCU PM<sub>10</sub> and PM<sub>2.5</sub> 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 the Department.
  - 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 PM<sub>10</sub> and PM<sub>2.5</sub>. Phillips 66 may reattempt a Method 201a at any time.
2. Phillips 66 shall test boilers #B-5 and #B-6 for NO<sub>x</sub> and CO compliance, both pollutants concurrently, on an every 5-year basis or according to another testing/monitoring schedule as may be approved by the Department (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<sub>x</sub> RATA testing, perform CO testing on the No. 3 H<sub>2</sub> 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 H-3901 Coker Furnace for NO<sub>x</sub> and CO concurrently to determine emissions on a lb/MMBtu basis. Thereafter, the Coker Furnace shall be tested for NO<sub>x</sub> 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 the Department's determination, shall be made in writing. (ARM 17.8.749).

7. 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, PM<sub>10</sub> (including condensables), PM<sub>2.5</sub> (including condensables), NO<sub>x</sub>, 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).
8. 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. SO<sub>2</sub> (SO<sub>2</sub> Board Ordered Stipulations as submitted in the State Implementation Plan (STIP), 40 CFR 60 Subpart Ja, ARM 17.8.749)
    - ii. O<sub>2</sub> (40 CFR 60 Subpart Ja)
    - iii. Volumetric flow rate (SO<sub>2</sub> STIP)
  - b. FCCU Stack
    - i. SO<sub>2</sub> (40 CFR 60 Subpart J and ARM 17.8.749)
    - ii. Volumetric flow rate (SO<sub>2</sub> 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<sub>x</sub> (ARM 17.8.749)
    - vi. O<sub>2</sub> (ARM 17.8.749)
  - c. Main Boiler Stack
    - i. SO<sub>2</sub> (SO<sub>2</sub> STIP; ARM 17.8.749)
    - ii. Volumetric flow rate (SO<sub>2</sub> STIP)
  - d. Boilers #B-5 and #B-6
    - i. NO<sub>x</sub> (40 CFR 60 Subpart Db)
    - ii. O<sub>2</sub> (ARM 17.8.749)
  - e. No. 3 Hydrogen Plant Heater H-8501

- i. NO<sub>x</sub> for NSPS Ja and BACT limitations on a lb/MMBtu basis. Phillips 66 shall determine the F factor of the fuel gas stream no less frequently than once per day. F factor determination and 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 O<sub>2</sub> 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).
- f. Vacuum Furnace H-17 and Large Crude Unit Heater H-24
- i. NO<sub>x</sub> for NSPS Ja and BACT limitations on a lb/MMBtu basis. Phillips 66 shall determine the F factor of the fuel gas stream no less frequently than once per day. F factor determination and 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 O<sub>2</sub> 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).
- g. Refinery Main Plant Relief Flare:
- i. H<sub>2</sub>S 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 SO<sub>2</sub> 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)
- h. 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 SO<sub>2</sub> emissions which result from gases going 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)
9. Enforcement of requirements, where applicable, shall be determined by utilizing data taken from CEMS and other Department-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 the Department.
    - b. Other stack testing may include, but is not limited to, the following air pollutants: SO<sub>2</sub>; NO<sub>x</sub>; ammonia (NH<sub>3</sub>); CO; PM, PM<sub>10</sub>, PM<sub>2.5</sub>, including condensable emissions; and VOC.
    - c. Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by the Department.
    - d. SO<sub>2</sub> 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).
  10. Phillips 66 shall install, operate and maintain the applicable STIP/SO<sub>2</sub> Control Plan required CEMS on the Jupiter Main Stack 1 (SO<sub>2</sub>, O<sub>2</sub> and volumetric flowrate), the FCCU Stack (volumetric flow rate), and the Main Boiler Stack (SO<sub>2</sub> 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).
  11. Phillips 66 shall install, operate and maintain applicable CEMS as originally required by federal consent decree on the FCCU (SO<sub>2</sub>, opacity, CO, NO<sub>x</sub>, and O<sub>2</sub>). 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.
  12. Phillips 66 shall install, operate and maintain the applicable NO<sub>x</sub> and O<sub>2</sub> 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 the Department, as appropriate (ARM 17.8.749).

13. 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 Department shall approve such contingency plans (ARM 17.8.749).
14. Compliance testing and continuous monitor certification shall be as specified in 40 CFR 60, Appendices A and B. Test methods and procedures, where there is more than one option for any given pollutant, shall be worked out with the Department prior to commencement of testing (ARM 17.8.749).
15. 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).
16. 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).
17. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).
18. The Department 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 SO<sub>2</sub> 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 the Department 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 the Department 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 the Department.
  - 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 the Department 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<sub>2</sub>S and NH<sub>3</sub>), 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<sub>2</sub> Plant PSA Offgas Vent. By the 30<sup>th</sup> 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<sub>2</sub> 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<sub>2</sub> Plant PSA Offgas Vent. By the 30<sup>th</sup> 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<sub>2</sub> 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<sub>2</sub> Plant PSA Offgas Vent. By the 30<sup>th</sup> 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<sub>2</sub> 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<sub>x</sub> rolling 365-day average and the maximum NO<sub>x</sub> 7-day rolling average per quarter for the FCCU stack. These reports shall also include NO<sub>x</sub> CEMS quarterly performance (excess emissions and monitor downtime) and Appendix F (Quality Assurance and Quality Control) provisions. FCCU quarterly NO<sub>x</sub> reporting shall be submitted in conjunction with the SO<sub>2</sub> 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 25<sup>th</sup> day of each month, the monthly and rolling 12 month total of hours of operation of the Backup Emergency Generator for the HDS Flare Drum Pump 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 25<sup>th</sup> day of each month, the monthly and rolling 12-month total NO<sub>x</sub> emissions from the H-3901, H-8401, H-8402, and No. 3 H<sub>2</sub> Plant Heater H-8501. 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 25<sup>th</sup> day of each month, the monthly and rolling 12-month total combined SO<sub>2</sub> 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 25<sup>th</sup> day of each month, the NO<sub>x</sub>, SO<sub>2</sub>, total filterable particulate, PM<sub>10</sub> (including condensibles), and PM<sub>2.5</sub> (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) (ARM 17.8.749). Until emissions factors are developed based on source testing, emissions factors as presented in the application for MAQP #2619-39 shall be used.
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 the department, shall be utilized. 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 the Department 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 (ARM 17.8.749).
2. Phillips 66 shall provide copies to the Department, upon the Department'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 (ARM 17.8.749).
3. Phillips 66 shall keep records and furnish reports to the Department 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 the Department, upon the Department'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).
6. Phillips 66 shall supply the Department'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).

7. Phillips 66 shall keep all records and furnish all reports to the Department 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).
8. Phillips 66 shall keep all records and furnish all reports to the Department as required by 40 CFR 63 Subpart CC, NESHAPs for Petroleum Refineries (MACT I) (ARM 17.8.749).
9. Phillips 66 shall keep all records and furnish all reports to the Department 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).
10. Phillips 66 shall keep all records and furnish all reports to the Department 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 the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the most recent emission inventory report and sources identified in this permit.

Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information 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):

<b>Point Name</b>	<b>Segment</b>	<b>Throughput Variable</b>
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-2: HDS #1	Fuel Gas	MMBtu
H-3: FCCU - Peabody Heater	Fuel Gas	MMBtu
H-4: HDS #3	Fuel Gas	MMBtu
H-5: Reformer #1 - Naptha Feed Heater	Fuel Gas	MMBtu
H-10: HDS #2 Charge Heater	Fuel Gas	MMBtu
H-11: HDS #2 Debutanizer Reboiler	Fuel Gas	MMBtu

Point Name	Segment	Throughput Variable
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-15: Refomer #1 - Reactor Heater	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
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 <sub>2</sub> 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

<b>Point Name</b>	<b>Segment</b>	<b>Throughput Variable</b>
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)
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

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

I. Notification

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

1. Pretest information forms must be completed and received by the Department 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 Department 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 the Department 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 the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.
- B. Waiver - The permit and 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 the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.
- F. Permit Inspection - As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department at the location of the source.
- G. 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) #2619-39

I. Introduction/Process Description

A. Source Description – Phillips 66 Company

The Phillips 66 Company, Billings Refinery (Phillips 66) is located at 401 South 23<sup>rd</sup> Street, Billings, Montana, in the NW<sup>1</sup>/<sub>4</sub> 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 7<sup>th</sup> 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

(H<sub>2</sub>S) 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 (Department), 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 H<sub>2</sub>S 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 SO<sub>2</sub> from the incinerator is absorbed and converted to ammonium bisulfite (ABS). The ABS is then used to absorb and react with H<sub>2</sub>S 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 H<sub>2</sub>S in the acid gas feed and reacts with NH<sub>3</sub> 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, SO<sub>2</sub> 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 ( $\text{Al}_2\text{O}_3$ ) 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  $\sim 500$  parts per million by weight (ppmw) to  $\sim 1$  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 SO<sub>2</sub> 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 SO<sub>2</sub> 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" SO<sub>2</sub> permit emission limit of 30.0 tons per year (TPY) (164 lb/day) and a limitation of fuel gas H<sub>2</sub>S 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 SO<sub>2</sub> emission limit for the "bubbled" 19 heaters must be

increased. The (19) Refinery Fuel Gas Heaters/Furnaces lb/day SO<sub>2</sub> 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" SO<sub>2</sub> 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 SO<sub>2</sub> State Implementation Plan (SIP) modeling (111.7 TPY). The annual "bubble" SO<sub>2</sub> limit of 30.0 TPY was maintained.

The Department 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, the Department 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" SO<sub>2</sub> permit limit of 529.17 lb/day.

The change in air emissions of other criteria pollutants (carbon monoxide (CO), nitrogen oxide (NO<sub>x</sub>), 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 SO<sub>2</sub> limit, simultaneous maximum firing of these heaters can be accomplished if the fuel gas H<sub>2</sub>S content stays below 49.75 ppmv. Conoco's amine systems produce fuel gas averaging (on an annual basis) of about 25 ppmv H<sub>2</sub>S content or less (see 1993 and 1994 Refinery EIS's). Since the emissions of CO, NO<sub>x</sub>, and VOC produced are not a function of H<sub>2</sub>S content, and Conoco's current amine system can generate appropriate fuel gas to stay at or below the 164 lb/day SO<sub>2</sub> 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 H<sub>2</sub>S 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 H<sub>2</sub>S under 49.75 ppmv, rendering the refinery to operate at un-optimized rates. This was the reason for the request to raise the daily SO<sub>2</sub> emissions limit for the "19-Heater" source. Since the proposed change to the heaters' SO<sub>2</sub> emissions limit does not reflect an annual increase in PTE, the project is not subject to PSD permitting review (threshold for SO<sub>2</sub> is 40 TPY).

In light of the SO<sub>2</sub> problem in the Billings-Laurel air shed, any change resulting in an increase of SO<sub>2</sub> 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. SO<sub>2</sub> modeling was completed by the Department to develop a revised SO<sub>2</sub> SIP for the Billings-Laurel area (see the Billings/Laurel SO<sub>2</sub> SIP Compliance Demonstration Report dated November 15, 1994). The "19-Heater source" was modeled using an SO<sub>2</sub> emission rate equivalent to 111.7 TPY to determine its SO<sub>2</sub> impact on the Billings-Laurel air shed. The results of this modeling showed there were no exceedances of the

SO<sub>2</sub> 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 SO<sub>2</sub> did not result in any violations of SO<sub>2</sub> 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 H<sub>2</sub>S) 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 SO<sub>2</sub> 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 SO<sub>2</sub> permit limits for the Coker heater and GOHDS heaters, an overall SO<sub>2</sub> 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<sub>x</sub> emission limits for the Coker Heater, Recycle Hydrogen Heater, Fractionator Feed Heater, and Hydrogen Plant Heaters. The NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emission limit to prevent any significant impacts. This permit alteration does not allow an increase in the annual NO<sub>x</sub> 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<sub>x</sub> (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<sub>x</sub> 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 the Department

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 SO<sub>2</sub> from the sulfur containing compounds in the PB Merox Unit off-gas stream to be calculated and counted against the current SO<sub>2</sub> 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). SO<sub>2</sub> 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 SO<sub>2</sub>. After a year of sampling time and with the approval of the Department, 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, the Department 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 Department 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, the Department 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, the Department 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 Department accepted the comments and made the changes, accordingly, in the Department decision version of the permit.

On March 1, 2001, the Department 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, the Department 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, the Department 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 Department 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, the Department issued **MAQP #2619-15** to clarify language regarding the Appendix F Quality Assurance requirements for the fuel gas H<sub>2</sub>S measurement system and to include certain limits and standards associated with the Consent Decree lodged on December 20, 2001, respectively. In addition, the Department 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 Department 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 hydrodesulfurization (HDS) unit, GOHDS unit, and hydrogen (H<sub>2</sub>) 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 SO<sub>2</sub> 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 the Department regarding comments received within the Department and from EPA, Conoco requested an extension to delay issuance of the Department Decision to December 9, 2002. Following additional discussion, Conoco and the Department 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 the Department on December 10, 2002, notified the Department 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 the Department. MAQP #2619-17 replaced MAQP #2619-16.

On December 11, 2003, the Department 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<sub>x</sub> burners (LNB) and flue gas recirculation (FGR) commonly referred to as ultra-low NO<sub>x</sub> burners (ULNB), new B-5 and new B-6 (previously referred to as B-7 and B-8), to meet the NO<sub>x</sub> emission reduction requirements stipulated in the EPA Consent Decree. On December 23, 2003, the Department deemed the application complete. This permitting action contained NO<sub>x</sub> emissions that exceed PSD significance levels. The replacement of the boilers resulted in an actual NO<sub>x</sub> 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 the Department. **MAQP #2619-18** replaced MAQP #2619-17.

On February 3, 2004, the Department 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 H<sub>2</sub> Unit. On March 1, 2004, the Department 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 H<sub>2</sub> 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<sub>x</sub> 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, the Department 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 the Department. MAQP #2619-19 replaced MAQP #2619-18.

On June 15, 2004, the Department 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 H<sub>2</sub>S 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, the Department 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 H<sub>2</sub> 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 H<sub>2</sub> Unit is to be deleted.
2. No. 2 H<sub>2</sub> 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 (PM<sub>10</sub>) exhaust emission factors for the combustion of PSA vent gas in the No.1 H<sub>2</sub> Heater and the No.2 H<sub>2</sub> 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 H<sub>2</sub> 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<sub>x</sub> 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 SO<sub>2</sub> 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, the Department 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 SO<sub>2</sub> 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 SO<sub>2</sub> emission limit of 25 parts per million, on a volume, dry basis (ppmvd), corrected to 0% oxygen (O<sub>2</sub>), on a rolling 365-day basis, and subject to an SO<sub>2</sub> emission limit of 50 ppmvd, corrected to 0% O<sub>2</sub>, on a rolling 7-day basis, and clarify the 7-day SO<sub>2</sub> 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 the Department issues permits. **MAQP #2619-22** replaced MAQP #2619-21.

The Department 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 Department 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, the Department 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 H<sub>2</sub> 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 SO<sub>2</sub>, PM, and PM<sub>10</sub> have now been triggered in the Billings area as of August 21, 2008. The minor source baseline date for NO<sub>x</sub> was already established by Yellowstone Energy Limited Partnership (formerly Billings Generation Inc.) on November 8, 1991.

In addition, the Department 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, the Department 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 the Department. 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<sub>x</sub> emissions from the FCCU shall have a limit of 49.2 parts per million, volumetric dry (ppmvd), corrected to 0% O<sub>2</sub>, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O<sub>2</sub>, on a rolling 7-day average. Per Paragraph 27 of the above-referenced CD, the 7-day NO<sub>x</sub> 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, the Department 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, the Department withheld preparation and issuance of a revised MAQP; however, this action was assigned MAQP #2619-26.

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

NO<sub>x</sub> emissions shall not exceed 49.2 ppmvd corrected to 0% O<sub>2</sub>, on a rolling 365-day average and 69.5 ppmvd, corrected to 0% O<sub>2</sub>, on a rolling 7-day average. The 7-day NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub> emission limits required by the CD. The letter included EPA's expectations as to how these NO<sub>x</sub> 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, the Department 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, the Department 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, the Department 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 the Department. **MAQP #2619-30** replaced MAQP #2619-29.

On May 1, 2014, the Department 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 tabulated 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 <sub>2</sub>	CEMS	71	CD	17.8.749
II.C.1.d.ii	FCC	SO <sub>2</sub>	7-day & 365-day limits	40	CD	17.8.749
II.C.1.d.vi	FCC	NO <sub>x</sub>	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
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 <sub>2</sub>	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 <sub>x</sub>	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 <sub>2</sub>	CEMS	28, 37	CD	17.8.749
II.E.5.b.i	FCC	SO <sub>2</sub>	CEMS	37	CD	17.8.749

MAQP #2619-30 Condition	Source	Pollutant	Obligation	CD Paragraph	Prior Permit Reference	New Regulatory Reference
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 <sub>2</sub>	RCFAs & FGRS	162	CD	17.8.749
II.A.1.c.iii	Flare-Refinery	SO <sub>2</sub>	NSPS J and A applicability	161	CD	17.8.749
II.A.1.c.iv	Flare-Jupiter	SO <sub>2</sub>	NSPS J and A applicability	155	CD	17.8.749
II.A.1.c.i	Heaters/Boilers	SO <sub>2</sub>	NSPS J applicability	69	none	17.8.749
II.C.1.e.i	Heaters	SO <sub>2</sub>	No fuel oil burning	**	none	17.8.749
II.C.1.e.iii	Heaters	SO <sub>2</sub>	Limit of 0.10 gr/dscf H <sub>2</sub> S in fuel gas	69	none	17.8.749
II.C.1.f.iv	Boilers	SO <sub>2</sub>	Limit of 0.10 gr/dscf H <sub>2</sub> S in fuel gas	69	none	17.8.749
II.C.1.f.ii	Boilers	SO <sub>2</sub>	300 ton/365-day rolling avg.***	71	CD	17.8.749
absent	Flare-Jupiter	SO <sub>2</sub>	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 <sub>x</sub> Emission = 49.2 ppmvd @ 0% O <sub>2</sub>  7-Day Rolling Average NO <sub>x</sub> Emission = 69.5 ppmvd @ 0% O <sub>2</sub>  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 <sub>2</sub> Emission = 25 ppmvd @ 0% O <sub>2</sub>  7-Day Rolling Average SO <sub>2</sub> Emission = 50 ppmvd @ 0% O <sub>2</sub>  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 <sub>2</sub> (Startup, Shutdown, or Malfunctions not used in determining compliance with this limit. - 2nd Amendment)  365-Day Rolling Average CO Emission = 150 ppmvd @ 0% O <sub>2</sub>	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 <sub>2</sub>	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)
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	Sec. II.A.1.a (General Condition) Sec. II.A.1.c.v (General Condition) Sec.II.E.5.b.iv

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

<b>Summary of Project-Impacted Emissions Units</b>			
<b>Emissions Unit</b>	<b>Type of Unit (Existing/New)</b>	<b>Maximum Capacity</b>	<b>Project Impact</b>
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.
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.

Summary of Project-Impacted Emissions Units			
Emissions Unit	Type of Unit (Existing/New)	Maximum Capacity	Project Impact
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).
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).

Summary of Project-Impacted Emissions Units			
Emissions Unit	Type of Unit (Existing/New)	Maximum Capacity	Project Impact
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 <sub>2</sub> 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 <sub>2</sub> 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.
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.

Summary of Project-Impacted Emissions Units			
Emissions Unit	Type of Unit (Existing/New)	Maximum Capacity	Project Impact
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 <sub>2</sub> 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.
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.

Summary of Project-Impacted Emissions Units			
Emissions Unit	Type of Unit (Existing/New)	Maximum Capacity	Project Impact
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	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).  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).
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, the Department 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, the Department 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 the Department 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, the Department received from Phillips 66 an application to modify the oxides of nitrogen (NO<sub>x</sub>) emissions limitations associated with the No. 1 H<sub>2</sub> Plant Reformer Heater, H-9401. Based on source testing, the 0.030 pound per million british thermal units (lb/MMBtu) NO<sub>x</sub> 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<sub>x</sub> 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<sub>x</sub>.

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

This permit action modified NO<sub>x</sub> limits associated with this heater to 0.042 lb/MMBtu. **MAQP #2619-36** replaced MAQP #2619-35.

On December 20, 2018, the Department 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, the Department 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, the Department 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.

### C. Current Permit Action

On September 23, 2020, the Department 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<sub>x</sub>), particulate matter with an aerodynamic diameter of 2.5 microns and less (PM<sub>2.5</sub>), particulate matter with an aerodynamic diameter of 10 microns or less (PM<sub>10</sub>), and greenhouse gases (GHGs). The project also triggers PSD for ozone based on NO<sub>x</sub>.

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.

<b>Emissions Unit</b>	<b>Existing/ New Unit</b>	<b>Project Impact</b>
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.

Emissions Unit	Existing/ New Unit	Project Impact
No. 5 HDS Charge Heater (H-9501) (EPN 78)	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 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. 5 HDS Stabilizer Reboiler Heater (H-9502) (EPN 79)	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 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.
SRU I (EPN 83)	Existing	The site is considering making physical changes to the SRU to make it capable of using oxygen enrichment, which would be operated as needed.
SRU II (EPN 84)	Existing	The site is planning to make several changes to the SRU, including the following: installation of a quench tower and a second ABS absorption tower; replacement of Claus reactor furnace burner; and blower and piping changes. Also, the site is considering making physical changes to the SRU to make it capable of using oxygen enrichment, which would be operated as needed.
SRU III (EPN 85)	Existing	The site is considering making physical changes to the SRU to make it capable of using oxygen enrichment, which would be operated as needed.

Emissions Unit	Existing/ New Unit	Project Impact
FCCU Stack (EPN 86)	Existing	The site is planning to make physical changes to the FCCU regenerator air grid as part of the project. Also, the actual feed rate to the FCCU is anticipated to increase as a result of the project. However, the FCCU regenerator's annual actual coke burn rate is anticipated to decrease as a result of the project because the FCCU reactor feed temperature will increase due to greater FCCU Preheater (H-18) (EPN 69) firing rates and specific project changes that will improve the amount of heat recovery in the FCCU.
Wastewater Components (EPN 93)	Existing	Several wastewater drains and a junction box will be added at the site as part of the No. 3 H <sub>2</sub> Plant.
Piping Fugitive Components (EPNs 94-97, 99)	Existing	Piping fugitive components (e.g., pumps, compressors, pressure relief devices, open-ended valves or lines, valves, and flanges or other connectors) will be added at the site as part of the project.
Delayed Coking Unit - Vent, Coke Cutting, and Water Handling (EPN 141)	Existing	The Coker Unit's annual actual coke production rate is expected to increase as a result of the project. There will also be a decrease in coke drum cycle times in association with this annual coke production rate increase. Therefore, the annual number of coke drum opening and coke cutting events is expected to increase as a result of the project.
Coke Handling (EPN 141)	Existing	The Coker Unit's annual actual coke production rate is expected to increase as a result of the project. Phillips 66 estimated that the project may cause the annual actual coke handling rate to increase by an amount equal to approximately 10% of the annual potential to emit coke handling rate. This estimated increase in actual coke handling will make use of existing coke handling equipment capacity that is not currently being used.
Railcar Clarified Oil Loading (EPN 142)	Existing	The FCCU's annual actual clarified oil production rate is expected to increase as a result of the project. Therefore, the annual amount of clarified oil loaded into railcars at the site is expected to increase as a result of the project. This estimated increase in actual clarified oil railcar loading will make use of existing railcar loading capacity that is not currently being used.

<b>Emissions Unit</b>	<b>Existing/ New Unit</b>	<b>Project Impact</b>
Storage Tanks (Multiple EPNs)	Existing	Specific storage tanks at the site are anticipated to experience an increase in their annual actual throughput as a result of the project. This estimated increase in actual storage tank throughput will make use of existing storage tank capacity that is not currently being used.
No. 3 H <sub>2</sub> Plant Reformer Heater	New	The heater is proposed to be constructed as part of the No. 3 H <sub>2</sub> Plant.
No. 3 H <sub>2</sub> Plant PSA Off-Gas Vent	New	The vent is proposed to be constructed as part of the No. 3 H <sub>2</sub> Plant.
Jupiter Main Stack Nos. 1 and 2 Emissions Cap	Existing	The site is planning to make physical changes to the three SRUs covered by the emissions cap. Also, the combined actual sulfur processing rate of the site's three SRUs is anticipated to increase as a result of the project.
Jupiter Sulfur Storage Tanks – Insignificant Activity (IA)	Existing	The site's annual actual sulfur production rate is expected to increase as a result of the project. Therefore, the annual amount of sulfur stored at the site is expected to increase as a result of the project. This estimated increase in actual sulfur throughput will make use of existing sulfur storage capacity that is not currently being used.
Jupiter Railcar and Tank Truck Sulfur Loading – IA	Existing	The site's annual actual sulfur production rate is expected to increase as a result of the project. Therefore, the annual amount of sulfur loaded into railcars and tank trucks at the site is expected to increase as a result of the project. This estimated increase in actual sulfur railcar and tank truck loading will make use of existing railcar and tank truck loading capacity that is not currently being used.

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.

D. Response to Public Comments

<b>Person/Group Commenting</b>	<b>Draft Permit Reference</b>	<b>Summarized Comment</b>	<b>Department Response</b>
Steve Torpey, Phillips 66 Company	II.A.1.d.iv	The H-24 should be referenced to the Large Crude Unit Heater	The error has been corrected
Steve Torpey, Phillips 66 Company	II.A.1.i.vi and vi	These should be renumbered	The error has been corrected
Steve Torpey, Phillips 66 Company	II.A.1.j.xii	References to this unit being new can be removed	The permit was updated to remove reference to the unit being new as part of the

			vacuum improvement project. The Vacuum Improvement Project was permitted in MAQP #2619-32.
Steve Torpey, Phillips 66 Company	II.A.2.b	As worded, grandfathered status of some sewers is removed	The permit was updated to clarify that only new or recommissioned sewer drains meeting applicability based on dates as specified in the rule are noted as affected units.
Steve Torpey, Phillips 66 Company	II.A.3.d	Tanks 78 and 79 have been demolished and can be removed from the permit	The permit was updated to remove the no longer existing units.
Steve Torpey, Phillips 66 Company	II.B.3	Adjust the wording to require additives as needed	The permit was updated as requested. No change to allowable emissions results.
Steve Torpey, Phillips 66 Company	II.B.14	This condition can be removed because the associated units were demolished as part of the Vacuum Improvement Project	The condition was removed as requested.
Steve Torpey, Phillips 66 Company	II.B.15	This condition can be updated to remove references to the unit being new	The condition was updated as requested. The unit was installed as part of the project permitted in MAQP #2619-32.
Steve Torpey, Phillips 66 Company	II.B.18	This condition should be changes from “shall operate” to “when necessary”	The Department agrees. The condition was further modified to clarify the timeframe as 56 days per rolling 12-month period.
Steve Torpey, Phillips 66 Company	II.B.21	The statement that SRU #2 shall be considered subject to NSPS Ja seems duplicative	At this time, the condition is maintained to ensure clarity that SRU #2 is required to be considered subject to NSPS Ja.
Steve Torpey, Phillips 66 Company	II.B.24	Reference to the unit as new can be removed, and the unit can be named CWT5	The permit was updated as requested. The unit was permitted under MAQP #2619-32
Steve Torpey, Phillips 66 Company	II.C.1.a footnote 2	Please modify to state “the ATS plant is not operating and/or during abnormal process condition, process upsets, and/or malfunctions.”	The permit was updated as requested.
Steve Torpey, Phillips 66 Company	II.C.1.b	Suggest this condition become condition II.C.2	The permit was updated as requested.
Steve Torpey, Phillips 66 Company	II.C.3	Restate the first sentence to remove “installed with” as SRU #3 and the stack are now existing	This condition was updated in clarification that a new stack is not being built as part of the current permit action. Requirement for SRU #3 to have its own stack remains.

Steve Torpey, Phillips 66 Company	II.C.4.d, II.C.5.b, II.C.5.c, II.C.5.h, II.C.5.j, II.C.5.l	The emissions limits do not match the presentation in the application.	The Department has corrected rounding error related discrepancies resulting in 0.01 ton per year corrections to these limitations.
Steve Torpey, Phillips 66 Company	II.C.6.c	The new No. 3 H <sub>2</sub> unit plant heater could be correctly added to this condition	The condition was modified to include that the PSA off-gas to be burned in the No. 3 H <sub>2</sub> plant heater is inherently low sulfur fuel. Additionally, a condition was added that only natural gas and PSA off-gas be burned in this unit, both of which are inherently low sulfur gas.
Steve Torpey, Phillips 66 Company	II.C.6.d	This condition should apply to both the H-9401 and H-9701	The condition is updated as requested.
Steve Torpey, Phillips 66 Company	II.C.6.o.i	The definition for lb/MMbtu is first made here, and the term is used earlier in the permit	The Department moved the definition to earlier in the permit.
Steve Torpey, Phillips 66 Company	II.C.6.q.ii	This heater cannot operate at greater than 90% efficiency on natural gas along – PSA off-gas and natural gas burning in the heater is the assumption for the emissions considerations.  Additionally, the reference to requirements which come from MACT 5D can be removed.	PSA off-gas would be expected to have a smaller amount of CO emissions than natural gas. The condition was modified to require that the unit be tested under normal operating firing rate and normal operating fuel mix.  The MACT 5D conditions were removed as requested. The unit is subject to these requirements through the MACT itself and there is no regulatory need to restate within this condition.
Steve Torpey, Phillips 66 Company	II.C.6.s	It is recommended that this condition be combined with other conditions for H-9401	The request was incorporated.
Steve Torpey, Phillips 66 Company	II.C.6.u	3.21 tons per year of NO <sub>x</sub> emissions should be provided for H-8401	In review of NAAQS modeling assumptions, this is an appropriate limit to be provided.
Steve Torpey, Phillips 66 Company	II.C.6.v	3.34 tons per year of NO <sub>x</sub> emissions should be provided for H-8402	In review of NAAQS modeling assumptions, this is an appropriate limit to be provided.
Steve Torpey, Phillips 66 Company	II.C.6.w	This condition is incomplete	The condition was deleted

Steve Torpey, Phillips 66 Company	n/a	Conditions II.C.6.d.xiv and xx from MAQP #2619-38 do not appear in the current MAQP	Individual emissions limitations review eliminated the need for these emissions limits.
Steve Torpey, Phillips 66 Company	Page 18	The numbering starting with the Main Boiler Stack needs adjustment	The conditions were renumbered as necessary
Steve Torpey, Phillips 66 Company	II.C.7	The vacuum improvement project cooling tower can be provided the name CWT5. The new cooling tower at Jupiter Sulphur, associated with this permitting action, has not yet been named.	The update was made as requested.
Steve Torpey, Phillips 66 Company	II.C.8	The primary oil water separator T-163 and the CPIs T-169 and T-170 have been removed from the site.	The request was incorporated as requested.
Steve Torpey, Phillips 66 Company	II.E.1	After review by Phillips 66 and Bison Engineering, Inc, the source testing consultant utilized by Phillips 66, it is not believed that a Method 201a will be able to be completed within the requirements of the Method, due to the high stack stream velocity	An attempt to complete the test is required. Should the test not be able to be accomplished within the requirements of the Method, an alternative monitoring plan has been agreed on consisting of utilizing a Method 5 with Method 202 back-half, and a particle size distribution determination.
Steve Torpey, Phillips 66 Company	II.E.6	The testing requirement should become effective after Coker Unit changes	The condition was updated as requested.
Steve Torpey, Phillips 66 Company	II.E.6	The second sentence can be removed because H-3901 only operates on fuel gas	The condition was updated as requested.
Steve Torpey, Phillips 66 Company	II.E.6	Propose to add “for NO <sub>x</sub> and CO” to the third sentence	The condition was updated as requested.
Steve Torpey, Phillips 66 Company	II.E.6	Propose to make SRU testing separate from H-3901 testing	The conditions were updated as requested.
Steve Torpey, Phillips 66 Company	II.E.6	Phased construction of the SRUs will require modification of the requirements	The condition was updated to ensure that full capacity testing is required within 180 days of the completion of modification of each SRU. The original wording of this condition lead to confusion.  Further, the NO <sub>x</sub> emissions limitation was adjusted to clarify at what point the new emissions limitation was effective.
Steve Torpey, Phillips 66 Company	II.E.7	Phillips 66 does not intend to calculate a daily F-factor	In consultation with Phillips 66, the form of the limit on

			the H-8501 was changed from a lb/MMBtu limit, to a ppmv limit, to accommodate the comment.
Steve Torpey, Phillips 66 Company	E.7.f	This condition applies to H-17 and due to reconstruction of H-24 in 2017, Phillips believes this heater should have the same NSPS requirements	The condition was updated as requested.
Steve Torpey, Phillips 66 Company	F.14	A method other than Method 120, such as 2510B, should be allowable	The condition was updated to allow 'another method as approved in writing by the Department'.

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 the Department. Upon request, the Department 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 the Department, provide the facilities and necessary equipment, including instruments and sensing devices, and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department. 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 the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq.*, 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 the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.
5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means which, without resulting in reduction 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 PM<sub>10</sub>

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<sub>x</sub> standards under this subpart and the SO<sub>2</sub> 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). The modifications made under MAQP #2619-39 did not qualify as a “modification” or “reconstruction” of this unit, therefore, NSPS J continues to apply as originally set by consent decree and continually required by the

MAQP for CO, SO<sub>2</sub>, PM and opacity provisions (ARM 17.8.749);  
and

3. Any other affected equipment
- e. 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 H<sub>2</sub> 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 Relief Flare Header).
  8. Any other affected equipment.
- f. 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>
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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.*

- g. 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-36	(currently out of service)
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
T-3201*	(Currently out of service)

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

- h. Subpart UU - Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture, applies to, but is not limited to, asphalt storage tank T-3201, and any other applicable storage tanks that commenced construction or modification after May 26, 1981. The PMA unit will be operating at 400°F, well under the asphalt's smoking temperature of 450°F; therefore, the tank vent opacity is expected to always have 0% opacity. There are no record-keeping requirements under this subpart. However, any malfunction must be reported as required under ARM 17.8.110, Malfunctions.
- i. Subpart GGG - 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 January 4, 1983.

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.

- 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, 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 H<sub>2</sub> 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 H<sub>2</sub> Unit and the No.5 HDS Unit
  - 13) HPU
  - 14) FCCU
  - 15) PB Merox Unit
  - 16) No. 3 Hydrogen Plant
- k. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems applies to the coker unit drain system, desalter wastewater break tanks, CPI separators, 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 H<sub>2</sub> Unit, the individual drain system in the No 3 H<sub>2</sub> 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 1821-32 and the No.5 HDS Unit, Tank T-4523, and any other applicable equipment, for equipment not overridden by 40 CFR 63, Subpart CC.

- l. 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 Backup Emergency Generator for the HDS Flare Drum Pump and any other applicable engines
  - m. 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 H<sub>2</sub> 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 H<sub>2</sub> 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 #2619-38 and therefore will continue to be subject to the existing FCCU provisions.

SRU #2 will have modifications 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 EEEEE - National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline); applies to the Proto storage tanks and any other applicable equipment.
- f. 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 Backup Emergency Generator for the HDS Flare Drum Pump, the Boiler House Backup Air Compressor engine, and any other applicable engines.
- g. 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 H<sub>2</sub> 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 the Department. Phillips 66 paid the appropriate application fee.
  2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit, excluding an open burning permit, issued by the Department. 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 Department may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.
- 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, PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, CO, VOC, and SO<sub>2</sub>; 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 published public notice in *The Billings Gazette* on September 25, 2020.

Additionally, as required by projects triggering the prevention of significant deterioration permitting requirements of Subchapter 8, the Department published public notice regarding issuance of the preliminary determination, on November 6, 2020, in *The Billings Gazette*.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.
7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.
8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.
9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving 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 the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.
11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or modified source may contain a condition providing that the permit will expire unless construction is

commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).
13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with  
  
ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.
14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of intent to transfer, including the names of the transferor and the transferee, is sent to the Department.
15. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to the Department 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, PM<sub>10</sub>, PM<sub>2.5</sub>, SO<sub>2</sub>, NO<sub>x</sub>, CO, and VOCs).

The action reviewed in MAQP #2619-39 triggers PSD for PM<sub>10</sub>, PM<sub>2.5</sub>, NO<sub>x</sub>, and GHG, as well as ozone because of NO<sub>x</sub>. The project emissions increases are described below. The project emissions increases are determined based on the PTE of new and physically modified units, plus the future projected actual emissions of units which are not physically modified but experience an increase in actual emissions as a result of the project, minus the baseline actual emissions from the project affected existing units. Only increases in emissions are determined. The net emissions increases are determined based on the project emissions increases plus (or minus) non-project related contemporaneous and creditable emissions changes. The following tables demonstrate:

<b>Potential to Emit of Physically Modified and New Units</b>							
	NO <sub>x</sub>	CO	VOC	SO <sub>2</sub>	PM <sub>(fil)</sub>	PM <sub>10(fil+cond)</sub>	PM <sub>2.5(fil+cond)</sub>
New No. 3 H <sub>2</sub> Plant Reformer Heater H-8501	17.48	14.98	1.23	0.13	0.59	1.53	1.05
New No. 3 H <sub>2</sub> Plant PSA Off-Gas Vent	n/a	26.82	0	n/a	n/a	n/a	n/a
New No. 3 H <sub>2</sub> Plant Fugitive Components	n/a	n/a	8.67	n/a	n/a	n/a	n/a
New No. 3 H <sub>2</sub> Plant Wastewater Components	n/a	n/a	3.07	n/a	n/a	n/a	n/a
New Jupiter Cooling Tower	n/a	n/a	0	n/a	0.27	0.27	0.27
Physically Modified FCCU - Regenerator Stack Emissions	72.08	106.36	0.001	26.33	53.22	47.34	47.34
Physically Modified SRU No. 2	71.50	18.46	0	50.00	17.52	35.04	35.04
Physically Modified SRU No. 1							
Physically Modified SRU No. 3							

<b>Future Projected Actual Emissions of Non-Physically Modified Project-Affected Units</b>							
	NO <sub>x</sub>	CO	VOC	SO <sub>2</sub>	PM <sub>(fil)</sub>	PM <sub>10(fil+cond)</sub>	PM <sub>2.5(fil+cond)</sub>
FCCU Preheater (H-18) - Full Capacity (PTE @ 77 MMBtu/hr)	33.05	27.77	1.82	2.75	0.40	0.76	0.71
Coker Furnace (H-3901) - Full Capacity	21.80	44.89	2.94	4.44	0.64	1.18	1.15
No. 4 HDS Recycle Hydrogen Heater (H-8401)	1.33	4.11	0.27	0.19	0.06	0.15	0.11
No. 4 HDS Fractionator Heater (H-8402)	3.91	11.85	0.776	0.43	0.17	0.44	0.30
No. 5 HDS Charge Heater (H-9501)	1.27	5.03	0.3	0.18	0.07	0.17	0.12
No. 5 HDS Stabilizer Reboiler Heater (H-9502)	3.5	16.4	1.068	0.57	0.23	0.60	0.41
Catalytic Reforming Unit #2 Heater 1 (H-13)	14.04	11.79	0.775	0.39	0.17	0.43	0.30
Catalytic Reforming Unit #2 Heater 2 (H-14)	6.98	5.86	0.38	0.20	0.08	0.22	0.15
Saturated Gas Stabilizer Reboiler (H-16)	14.73	12.38	0.806	0.41	0.18	0.47	0.32
Catalytic Reforming Unit #2 (H-23)	13.66	11.48	0.756	0.38	0.17	0.43	0.29
Alkylation Heater (H-21)	24.39	20.49	1.34	0.82	0.29	0.76	0.52
Coke Handling	n/a	0	0	0	0.44	0.30	0.18
Delayed Coking Unit			5.68				
Railcar Clarified Oil Loading	n/a		5.44		n/a	n/a	n/a
Storage Tanks (incremental increase only)	n/a	n/a	5.36	n/a	n/a	n/a	n/a

<b>Baseline Actual Emissions of Modified and Nonmodified Project Affected Units (Average of CY 2018 and 2019)</b>							
	NO <sub>x</sub>	CO	VOC	SO <sub>2</sub>	PM <sub>(fil)</sub>	PM <sub>10(fil+cond)</sub>	PM <sub>2.5(fil+cond)</sub>
Physically Modified SRU No. 2	44.11	1.8	0	22.1	2.53	7.06	7.06
Physically Modified SRU No. 1							
Physically Modified SRU No. 3							
Physically Modified FCCU - Preheater H-18	28.4	23.86	1.56	0.75	0.34	0.61	0.61
Physically Modified FCCU - Regenerator Stack	68.68	84.93	0.001	23.37	49.71	43.57	43.57
Coker Furnace (H-3901)	20.55	42.32	2.77	1.31	0.6	1.08	1.08
No. 4 HDS Recycle Hydrogen Heater (H-8401)	1.09	3.27	0.21	0.11	0.047	0.12	0.084
No. 4 HDS Fractionator Heater (H-8402)	3.66	10.99	0.72	0.34	0.16	0.41	0.28
No. 5 HDS Charge Heater (H-9501)	1.11	4.16	0.27	0.13	0.059	0.15	0.11
No. 5 HDS Stabilizer Reboiler Heater (H-9502)	3.18	15.42	1.01	0.48	0.22	0.57	0.39
Catalytic Reforming Unit #2 Heater 1 (H-13)	13.58	11.4	0.75	0.35	0.16	0.42	0.29
Catalytic Reforming Unit #2 Heater 2 (H-14)	6.8	5.71	0.37	0.18	0.082	0.21	0.15
Saturated Gas Stabilizer Reboiler (H-16)	14.26	11.98	0.78	0.37	0.17	0.45	0.31
Catalytic Reforming Unit #2 (H-23)	13.19	11.08	0.73	0.34	0.16	0.41	0.28
Alkylation Heater (H-21)	21.12	17.74	1.16	0.55	0.25	0.66	0.45
Delayed Coking Unit			5.43				
Railcar Clarified Oil Loading			2.15				
Coke Handling	n/a	0	0	n/a	0.36	0.25	0.16

<b>Project Emissions Increase = PTE (New and Physically Modified Units) + Projected Future Actuals (Nonmodified Units) - Baseline Actuals</b>							
	NO <sub>x</sub>	CO	VOC	SO <sub>2</sub>	PM <sub>(fil)</sub>	PM <sub>10 (Fil + cond)</sub>	PM <sub>2.5(fil + cond)</sub>
Project Emissions Increase	59.99	94.01	22.77	36.82	19.64	34.11	33.44
PSD Significant Emissions Rate	40	100	40	40	25	15	10

### GHG Emissions

<b>Potential to Emit of New and Modified Units</b>			
	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
New No. 3 H2 Plant Reformer Heater H-8501	111,795	2.3	0.41
New No. 3 H2 Plant PSA Off-Gas Vent	160	16.64	
New No. 3 H2 Plant Fugitive Components			
New No. 3 H2 Plant Wastewater Components			
Physically Modified FCCU - Regenerator Stack Emissions	287,846	8.43	1.69
Physically Modified SRU No. 2	65,790	0.24	0.02
Physically Modified SRU No. 1			
Physically Modified SRU No. 3			

<b>Future Projected Actual Emissions of Non-Physically Modified Project-Affected Units</b>			
	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
FCCU Preheater (H-18) - Full Capacity (PTE @ 77 MMBtu/hr)	45,867	2.23	0.44
Coker Furnace (H-3901) - Full Capacity	74,127	3.61	0.72
No. 4 HDS Recycle Hydrogen Heater (H-8401)	6,217	0.33	0.06
No. 4 HDS Fractionator Heater (H-8402)	17,606	0.95	0.19
No. 5 HDS Charge Heater (H-9501)	6,867	0.37	0.08
No. 5 HDS Stabilizer Reboiler Heater (H-9502)	24,176	1.31	0.26
Catalytic Reforming Unit #2 Heater 1 (H-13)	17,435	0.95	0.19
Catalytic Reforming Unit #2 Heater 2 (H-14)	8,654	0.47	0.092
Saturated Gas Stabilizer Reboiler (H-16)	18,299	0.99	0.2
Catalytic Reforming Unit #2 (H-23)	16,973	0.92	0.19
Alkylation Heater (H-21)	30,678	1.65	0.33
Coke Handling			
Delayed Coking Unit		16.89	

<b>Baseline Actual Emissions (Average of CY 2018 and 2019)</b>			
	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
-			
Physically Modified SRU No. 2	48,627	0.1	0.01
Physically Modified SRU No. 1			
Physically Modified SRU No. 3			
Physically Modified FCCU - Preheater H-18	35,149	1.92	0.38
Physically Modified FCCU - Regenerator Stack	208,366	6.1	1.22
Coker Furnace (H-3901)	62,324	3.4	0.68
No. 4 HDS Recycle Hydrogen Heater (H-8401)	4,823	0.26	0.05
No. 4 HDS Fractionator Heater (H-8402)	16,190	0.88	0.18
No. 5 HDS Charge Heater (H-9501)	6,122	0.33	0.07
No. 5 HDS Stabilizer Reboiler Heater (H-9502)	22,717	1.24	0.25

Catalytic Reforming Unit #2 Heater 1 (H-13)	16,795	0.92	0.18
Catalytic Reforming Unit #2 Heater 2 (H-14)	8,408	0.46	0.09
Saturated Gas Stabilizer Reboiler (H-16)	17,644	0.96	0.19
Catalytic Reforming Unit #2 (H-23)	16,318	0.89	0.18
Alkylation Heater (H-21)	26,136	1.43	0.29
Delayed Coking Unit		16.15	

PTE + Future Actuals - Baseline Actuals				
	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O	CO <sub>2</sub> e*
Project Emissions Increases:	242,871	23.24	1.10	243,780
PSD Significant Emissions Rate:				75,000

\*Note: Methane (CH<sub>4</sub>) has a global warming potential of 25  
Nitrous oxide (N<sub>2</sub>O) has a global warming potential of 298

To arrive at the net emissions increases, where the project emissions increases are greater than significant emissions rates, contemporaneous and creditable emissions changes are added (or subtracted) from the project emissions increases. To be contemporaneous, the emissions change must have occurred within 5 years of the current project's emissions increase. An increase or decrease in actual emissions is creditable only if the Department has not relied on it in issuing a permit under subchapter 8, which permit is in effect when the increase in actual emissions from the particular change occurs. The following table as included in the application demonstrates. Because the Vacuum Improvement Project received PSD review for PM, PM<sub>10</sub>, and PM<sub>2.5</sub>, as well as GHGs, those emissions are not creditable. Where project emissions increases alone are less than significant emissions increases, no further netting is required. The current application triggers PSD program requirements for NO<sub>x</sub>, PM<sub>10</sub>, PM<sub>2.5</sub>, GHG's, and pursuant to ARM 17.8.801(28)(a), ozone, based on the significant increase in NO<sub>x</sub>.

Project	Startup Date	Type of Emissions Change	CO (tpy)	NO <sub>x</sub> (tpy)	PM (filter. only) (tpy)	PM <sub>10</sub> (tpy)	PM <sub>2.5</sub> (tpy)	SO <sub>2</sub> (tpy)	VOC (tpy)	H <sub>2</sub> S (tpy)	CO <sub>2</sub> e (tpy)
Boiler House Backup Air Compressor Engine and Coker Backup Air Compressor Engine Project <sup>2</sup>	5/1/2017	Increase	0.005	0.18	-	-	-	0.08	0.002	-	-
		Decrease	0	0	-	-	-	0	0	-	-
Vacuum Improvement Project <sup>3</sup>	5/31/2017	Increase	83.63	62.15	-	-	-	38.37	28.95	0.90	-
		Decrease	-24.40	-40.46	-	-	-	-0.28	-2.10	0	-
NaHS Project	5/14/2019	Increase	-	-	-	-	-	-	-	0.02	-
		Decrease	-	-	-	-	-	-	-	0	-
Flare Drum Backup Pump Engine Project <sup>4</sup>	8/31/2019	Increase	0.86	0.99	-	-	-	0.02	0.37	-	-
		Decrease	0	0	-	-	-	0	0	-	-
Billings Projects for 2022	Est. 7/2021 <sup>5</sup>	Increase	94.00	60.01	19.40	33.88	33.22	36.83	22.75	0.66	243,782
		Decrease	0	0	0	0	0	0	0	0	0
<b>Net Emissions Increase:</b>			N/A	<b>82.87</b>	N/A	<b>33.88</b>	<b>33.22</b>	N/A	N/A	N/A	<b>243,782</b>
<b>PSD Significant Threshold:</b>			100	40	25	15	10	40	40	10	75,000
<b>Subject to PSD Review? (Yes/No):</b>			No	<b>Yes</b>	No	<b>Yes</b>	<b>Yes</b>	No	No	No	<b>Yes</b>

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 the Department 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 SO<sub>2</sub> nonattainment area centered around the CHS refinery. The current project does not pose a significant emissions increase of SO<sub>2</sub>.

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 the Department may establish by rule; or
  - c. PTE > 70 TPY of PM<sub>10</sub> in a serious PM<sub>10</sub> 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 #2619-39 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 PM<sub>10</sub> 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, the Department determined that Phillips 66 is subject to the Title V operating permit program.

### III. BACT Determination

ARM 17.8. Subchapter 7 requires BACT determinations for each new or modified source. ARM 17.8 Subchapter 8 requires, in overlapping fashion, the same requirements for those pollutants which trigger Subchapter 8 review. Phillips 66 shall install on the new or modified source the maximum air pollution control capability that is technically practicable and economically feasible. The application presents BACT proposals in the standardized top-down format. A summary of the Department's BACT review and determinations as well as background information is presented below.

#### **No. 3 Hydrogen Plant Heater H-8501**

The No. 3 H<sub>2</sub> Plant Heater will combust pipeline quality natural gas and PSA off-gas. The PSA off-gas consists of methane, hydrogen, carbon monoxide, carbon dioxide, water, and nitrogen. The heater will be equipped with separate burner tips for each fuel. The heater will have the typical pollutants seen in a natural gas fired heater, with exception that VOC emissions would not be expected under PSA-off-gas operations.

Because pipeline quality natural gas is required to be inherently low in sulfur, sulfur dioxide (SO<sub>2</sub>) emissions would be nearly negligible, negating any feasibility for add-on SO<sub>2</sub> emissions controls or fuel treatment requirements. Additionally, the PSA off-gas is sulfur free.

While good combustion is inherent to the combustion of the small chain/low carbon hydrocarbons, imperfect combustion still produces small amounts of CO, as well as VOC, PM, and HAPs, which are products of incomplete combustion.

Add on controls that enhance combustion are available including catalytic and thermal oxidation. However, they are not appropriate in this case because adding such controls to units with lower exhaust temperatures would require the exhaust be brought to higher temperatures, requiring more fuel combustion. This poses technical and economic challenges, as well as unbalanced environmental impacts, which do not represent BACT in this case.

This heater will be subject to 40 CFR 63 Subpart DDDDD. The standard requires, in the case of this heater, annual tuning to maximize efficient combustion of the fuels. Although 40 CFR 63 Subpart DDDDD is aimed at minimizing HAP emissions, the standard utilizes CO as a surrogate in assessing incomplete combustion and requires measurement of CO as part of the tuning process. This practice minimizes not only organic HAPs, but all products of incomplete combustion, such as CO, VOC, and PM. It should be noted there may also be decreased GHG emissions as a result, due to checking for maximum combustion efficiency annually. The Department accepts the work practices required by 40 CFR 63 Subpart DDDDD as BACT for VOC and PM for this heater. Because of the inherently low emissions of VOC and PM, any add-on control technology would be infeasible.

Given the inverse relationship between NO<sub>x</sub> and CO, and the feasibility of testing each, a CO limitation is recommended for this heater. A limit of 0.03 lb/MMBtu (HHV) on a 1-hr basis, is prescribed as the minimum BACT for CO for this heater. This limitation is reflective of BACT under natural gas combustion operations.

Emissions of NO<sub>x</sub> would result from the combustion of each fuel. Ultra-low NO<sub>x</sub> burners (ULNBs), through any number of techniques, ultimately provide for less thermal NO<sub>x</sub> formation. It is well established that selective catalytic reduction, selective non-catalytic reduction, and nonselective catalytic reduction are not feasible for process heaters of this size and type. A New Source Performance Standard, NSPS Ja, applies to this heater, and requires a performance of 0.040 lb/MMBtu on a higher heating value, 30-day rolling average. P66 has proposed a BACT limitation of 0.035 lb/MMBtu on a higher heating value, 30-day rolling average basis, utilizing ULNBs. The Department will require a NO<sub>x</sub> CEMS to monitor compliance with the limit, which is also a requirement of the NSPS.

Regarding GHG emissions, an emissions limitation in the form of a lb of pollutant per MMBtu of fuel burned would not serve as a demonstration of thermal efficiency/GHG emissions minimization, rather, more of a demonstration of the characteristics of the fuel being burned. In addition, add-on controls to remove GHGs from exhaust streams are limited. Therefore, based on the amount of emissions inherent to clean burning lower carbon fuels such as natural gas and refinery fuel gas, combined with the size of the heaters and cost and availability/proximity of carbon sequestration, add on controls are not feasible. Thermal efficiency is currently an important design standard which minimizes GHG emissions in heaters and provides a design standard which maximizes the amount of usable heat per each Btu burned. The Department accepted an overall thermal efficiency of up to 83% as an acceptable design standard for purposes of BACT. This thermal efficiency exceeds the 80% efficiency seen in other boiler/process heater BACT determinations.

### **FCCU Catalyst Regenerator**

The purpose of the FCCU regenerator is to capture and treat the catalyst for re-use. The catalyst in the FCCU, due to coke layer build-up, requires thermal treatment to burn-off the coke layer, which is essential to maintaining catalyst activity. Operations of the FCCU regenerator result in emissions of NO<sub>x</sub>, SO<sub>2</sub>, GHGs, products of incomplete combustion (CO, PM/PM<sub>10</sub>/PM<sub>2.5</sub>) from the coke burn-off, and micro-fines (PM/PM<sub>10</sub>/PM<sub>2.5</sub>) from catalyst attrition.

Because of the unit's exhaust temperature, thermal or catalytic oxidation is not feasible to reduce products of incomplete combustion. A CO combustion promoter is available, and already utilized, in this unit. The CO combustion promoter increases the reaction rate constant for the CO-to-CO<sub>2</sub> oxidation, resulting in more complete combustion.

The unit is already subject to a CO limitation of 500 parts per million on a dry, rolling 365 day basis, corrected to 0% excess air. This limit originates from a consent decree, which required NSPS J performance from this unit, and has been demonstrated achievable. The use of the CO combustion promoter was essential in developing such standard. The Department set a CO limit of 500 ppmvd corrected to 0% excess air, on a 365 day rolling average basis, as BACT, reaffirming this limit will continue to apply under new operations. The CO emissions are required to be monitored using CEMS.

Filterable PM emissions are minimized by routing the FCCU regenerator flue gas through three stages of high efficiency cyclones, while a portion of the third stage cyclone is routed through a fourth stage high efficiency cyclone or filter. The unit is subject to a total filterable particulate matter emissions limit of 1 lb/1,000 lb of coke burned, which was imposed through a consent decree. The limit has been demonstrated achievable, and additional add-on controls would not be economically feasible. Routing the entirety of the third stage cyclone through a fourth stage would entail significant design changes which would not be economical given the additional control achieved. The current PM limit is in-line with other recent PSD BACT determinations for an FCCU of this age and is set as BACT for this unit.

Annualized allowable SO<sub>2</sub> emissions was reduced from 48.86 tons per year to 26.33 tpy by creating a BACT limit of 6.01 lb/thousand barrels of gas oil feed as determined monthly on a rolling 12-month basis. This is achievable in part because increases to the FCCU reactor feed temperature will allow for less total catalyst regeneration. The unit is already operated with SO<sub>2</sub> reducing catalyst additives. No controls beyond the SO<sub>2</sub> emissions reducing catalyst already in use are found feasible in this case.

VOC emissions are inherently low to the FCCU, making add-on controls infeasible. However, operating with good combustion efficiency as monitored via CO and O<sub>2</sub> CEMS and the CO emissions limits, ensures the low VOC emissions. No additional add-on controls or requirements were found needed or feasible in the case of VOC emissions from the FCCU catalyst regenerator stack, however, it should be noted that the CO BACT conditions are also BACT conditions for VOC. The same is true for GHG emissions, in that maximized combustion leads to minimization of wasted energy.

In addition to thermally formed NO<sub>x</sub>, the FCCU catalyst regeneration process emits NO<sub>x</sub> because a portion of the nitrogen contained in the coke converts to NO<sub>x</sub> during the combustion process, in the same manner fuel bound nitrogen leads to creation of “fuel NO<sub>x</sub>”. The application demonstrates that selective catalytic reduction and selective noncatalytic reduction would be economically infeasible. Further, in the case of selective noncatalytic reduction, ammonia slip adds an environmental impact to visibility and secondary particulate matter. The Department accepted a proposed limitation of 49.2 ppmvd at 0% oxygen on a 356-day rolling average basis as BACT. Given the changes occurring at the facility, maintaining this limitation provides potentially an increase in overall control requirements, as differing crude oil slates may bring increased nitrogen content. The facility will need to hydrotreat the FCCU feed which reduces nitrogen compounds present in the feed and continue to utilize catalyst additives, as well as process control, to meet the limit.

### **SRU No. 1, 2, and 3**

SRU No. 1 and No. 3 uses two parallel processes to convert sulfur bearing gasses from the refinery. One processes utilizes the Claus thermal reactor followed by a Claus catalytic reactor. The other uses an ammonium thiosulfate tower. The tail gas stream is combined and routed through a sulfur oxidizer, quench tower, two absorption towers (wet scrubbers), and three vent gas filter vessels.

SRU No. 2 uses the Claus thermal reactor followed by a Claus catalytic reactor. The tail gas is routed through a sulfur oxidizer, quench tower, two absorption towers (wet scrubbers),

and three vent gas filter vessels.

SRU No. 1 and No. 2 share the same emissions stack, Jupiter Main Stack No. 1. SRU No. 3 has its own stack, Jupiter Main Stack No. 2.

Changes taking place in this project is adding the capability for oxygen enrichment for SRU No. 1 and No. 3; and additionally for SRU No. 2, installation of a quench tower and second absorption tower, replacement of the Claus reactor furnace burner, and blower and piping changes. An overall increase in sulfur production capability is expected to occur.

The SRUs already incorporate a thermal oxidation process, the tail gas sulfur oxidizer. The low temperature of exhaust gases and presence of sulfur make follow-up catalytic oxidation technically infeasible. Therefore, for CO and VOC, good combustion practices provides for BACT.

Regarding PM/PM<sub>10</sub>/PM<sub>2.5</sub>, the unit is currently equipped with two wet gas scrubbers in series, followed by high efficiency vent gas filters. Electrostatic precipitators would be technically feasible, however, the currently installed control technologies provide nearly the same emissions reduction with no additional cost associated with retrofitting and replacing currently installed controls. Any increases in performance would come with very high costs from a cost envelope type of analysis, in this case. The Department agreed that removal of current controls and retrofitting an electrostatic precipitator would pose economic feasibility issues in this case. As a note, cyclones would not appropriately control the small partial particulate emitted from this unit and were eliminated from further consideration based on lack of performance in this application.

As previously noted, an increase in overall sulfur recovery capacity is expected as a result of this project. Therefore, maintaining the current limitations on the sulfur recovery units results in an increase in emissions performance in terms of particulate matter emitted per unit of sulfur recovered. Further, Phillips 66 recently underwent significant research and exploration of and implementation of modifications in order to achieve compliance with the current limitations. For more information, review the permitting action which took place in MAQP #2619-38. A limitation of 2.0 lb/hr of total filterable particulate on a 1-hr average basis, is prescribed as BACT. Meeting this limit required several process changes including adding a heat exchanger to SRU #2 tail gas, adding additional sodium hydrosulfide vents to SRU I and III, adding mist spray to top and bottom of gas filters, adding mist spray to the main stacks, adding additional filters to filter vessels, and repositioning and replacing spray nozzles in quench towers. A limit of 2.0 lb/hr remained.

The intent of the sulfur recovery facility is to recover sulfur for sale as various products. The process, by design, significantly reduces the SO<sub>2</sub> emissions of the refinery by recovering the sulfur. Although most of the sulfur-containing compounds present in the acid gas and sour water stripper gas streams that are fed to the SRUs are converted to elemental sulfur, CO<sub>2</sub>, water, and ammonium thiosulfate, a relatively small amount of the sulfur-containing compounds exit the SRU's parallel Claus and ATS processes in respective "tail gas" streams. These tail gas streams are combined and routed to the SRU's tail gas treatment process where they are first combusted in a sulfur oxidizer to convert most of the sulfur compounds to SO<sub>2</sub>. The exhaust gas from the sulfur oxidizer is then routed to a quench tower and then to two absorption towers in series where water and ammonia are used to absorb and react

with the SO<sub>2</sub> generated in the oxidizer to produce ammonium bisulfate. The SO<sub>2</sub> exiting the absorption towers and downstream gas filters is emitted to the atmosphere.

There is a currently applicable NSPS standard for the SRUs that requires SO<sub>2</sub> emissions not exceed 250 ppmvd at 0% excess oxygen, based on a rolling 12-hour average. The Department has previously set a limit of 167 ppmvd at 0% O<sub>2</sub>, or in the case of SRU No. 3, at 3% O<sub>2</sub>, based on a 12-hour rolling average. This limit is maintained in this action as BACT.

### **No. 3 H<sub>2</sub> Plant PSA Off-gas**

The No. 3 H<sub>2</sub> Plant PSA Off-Gas Vent will briefly vent during the startup of the No. 3 H<sub>2</sub> Plant. The No. 3 H<sub>2</sub> Plant's PSA off-gas will normally be routed to the No. 3 H<sub>2</sub> Plant Reformer Heater for combustion as a gaseous fuel. However, the PSA off-gas will not be a suitable source of fuel for the heater during the plant's startup process because it will not be reliably available or possess stable heating value characteristics since it cannot be generated in a steady-state manner until a base level of raw hydrogen is produced in order to begin filling and cycling the plant's PSA system. The No. 3 H<sub>2</sub> Plant PSA Off-Gas Vent will be comprised of methane, hydrogen, CO, CO<sub>2</sub>, water, and nitrogen. Note, no VOC species are present.

In reviewing the feasibility of a dedicated flare for the off-gas, it was noted that pilot gas and use of mixing steam when needed, may actually result in a net increase in emissions. Although venting would be infrequent, the high flow rate during the event would pose technical infeasibilities to using the current flare system, as it would unbalance the flare gas recovery system leading to SO<sub>2</sub> emissions issues.

Quite simply, minimization of PSA off-gasing is the best choice. Off-gasing will be allowed only during startup of the unit, which is to be minimized. Further, emissions of CO from the vent shall not exceed 26.82 tons per year, on a rolling 12-month basis. Every instance of PSA off-gasing will be required to be documented, emissions estimated, and explanation as to reason for the startup provided. CO is chosen as the pollutant of limitation because it is a criteria pollutant, however GHG emissions would also be required to be estimated and reported in accordance with GHG reporting rules, and the same requirements serve as BACT for GHGs.

### **No. 3 H<sub>2</sub> Plant Wastewater Components**

VOC emissions from uncontrolled wastewater drains and junction boxes occur when the VOCs evaporate or otherwise become vapor phased and separate from the wastewater stream. Due to the nature of junction boxes, the potential emissions from the junction boxes are higher than from drains themselves.

The wastewater drains and junction box will be subject to NSPS Subpart QQQ, NESHAP FF, and MACT CC. As explained in the application, the open drain risers will be equipped with a water seal, which will significantly reduce the ability of the VOC contained in the vapor space of the drain system to be emitted to the atmosphere from the drain riser. However, some VOC emissions will occur from the surface of the drain water seal or by diffusion through the water seal. The junction box, at a minimum, will be equipped with a tightly sealed cover fitted with a vent pipe possessing length and diameter parameters that

will lengthen the diffusion pathway and limit the area open to the atmosphere, respectively, thus reducing the ability of the VOC contained in the junction box vapor space to be emitted to the atmosphere. No further controls are necessary as BACT.

### **New Piping Fugitive Components**

VOC emissions occur from piping fugitive components through faulty installation and degradation or failure of seals/seal systems. New piping components installed will be subject to NSPS GGGa, and MACT CC, which require monitoring for any leaks. Such practice is referred to as “LDAR”, or leak detection, repair and replacement programs.

The applicable NSPS and MACT rules provide detailed LDAR requirements. No further requirements are deemed necessary as BACT.

### **New Cooling Tower**

Dissolved solids in cooling tower water can result in emissions of particulate matter due to the liquid entrainment in exhaust air from the cooling tower. There are two primary ways to minimize these emissions. One is to minimize the amount of splashing that occurs from the towers, via use of mist eliminators. Drift eliminators greatly reduce the amount of liquid droplets that remain entrained in exhaust air via physical contact with the entrained liquid. Another way to control the particulate matter emissions is via controlling dissolved solids.

P66 proposed drift eliminators with a design drift rate of 0.0010%. This matches the design drift rate of recently permitted cooling towers at this site, and represents a high performance drift eliminator. P66 also proposes to maintain conductivity in the cooling tower water to 3,130 microsiemens per centimeter, at 25 degrees celcius. Because total dissolved solids can be measured utilizing EPA water analysis methods via direct measurement of conductivity, such limitations provides for a practically enforceable limitation which can be measured to monitor compliance.

It should be noted that an air-cooled heat exchanger design was briefly explored. Such design would eliminate particulate matter related emissions from the heat exchanger. However, because the process fluid must be cooled to a temperature less than 25 degrees farhenheight above the ambient temperature, this type of heat exchanger sill not be technically feasible, as summer-time temperatures in the Billings area precludes this.

The Department accepts high efficiency drift eliminators with a design drift rate of 0.0010%, combined with dissolved solids control with a conductivity equivalent of 3,130 microseimens per centimeter at 25 degrees celcius, as BACT for this cooling tower.

## IV. Existing Air Quality

Phillips 66 is located at 401 South 23<sup>rd</sup> 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 in attainment of all National Ambient Air Quality Standards (NAAQS). The Laurel SO<sub>2</sub> nonattainment area is about 31.9 kilometers (19.8 miles) southwest from the center of the main operating facility.

## V. Air Quality Impacts Analyses

The current permit action triggers PSD review for NO<sub>x</sub>, PM<sub>10</sub> (filterable plus condensable), PM<sub>2.5</sub> (filterable plus condensable) and due to NO<sub>x</sub>, ozone. The PSD program, intended to keep areas which are currently in attainment of ambient air quality standards from quickly degrading (i.e. to prevent significant deterioration of ambient air quality), requires that the permitted project be shown to not only be protective of the ambient air quality standards, but also to not cause an exceedance of applicable increment, which is the maximum amount of degradation of ambient air allowed by projects required to demonstrate such.

Ambient air quality impacts are determined through use of complex modeling, which mathematically estimates maximum air quality impacts based on emissions rates, stack parameters, meteorology, and terrain. A summary of results is presented in the table below, followed by detailed explanation of inputs, analyses, and results:

Pollutant	Averaging Period	Class II Modeled Significant Impact (ug/m3)	Class II Significant Impact Level (ug/m3)	Class II Modeled Increment (ug/m3)	Class II Increment (ug/m3)	Class II Modeled NAAQS (ug/m3)	Class II NAAQS (ug/m3)	Class I Modeled Significant Impact (ug/m3)	Class I Significant Impact Level (ug/m3)	Class I Modeled Increment (ug/m3)	Class I Increment (ug/m3)
PM <sub>10</sub>	24-hour	3.4	5	NA	30	NA	150	0.1	0.3	NA	8
	Annual	0.3	1	NA	17	NA	-	0.004	0.2	NA	4
PM <sub>2.5</sub>	24-hour	2.8	1.2	4.6	9	16.4	35	0.09	0.27	NA	2
	Annual	0.3	0.2	0.5	4	6.9	12	0.004	0.05	NA	1
Ozone	8-hour	0.19	1.96	NA	-	NA	137	NA	-	NA	-
NO <sub>2</sub>	1-hour	86.8	7.5	NA	-	157.4	188	-	-	NA	-
	Annual	0.9	1	NA	25	NA	100	0.008	0.1	NA	2.5

Ramboll US Corporation (Ramboll) conducted air quality modeling for the proposed “Billings Projects for 2022” as part of the Phillips 66 air quality permit application. This ambient air impact analysis was conducted pursuant to the requirements of ARM 17.8.820 and ARM 17.8.822 to demonstrate that the proposed modification would not cause or contribute to a violation of any NAAQS, MAAQS or applicable PSD increment (PSD Class II Air Quality Analysis); pursuant to ARM 17.8.825; pursuant to ARM 17.8.1106 to show that the project does not cause or contribute to any adverse impact on visibility within any federal Class I areas (PSD Class I Air Quality Analysis and PSD Class I Area Impact Analysis); and pursuant to ARM 17.8.824 to show that the project does not cause or contribute to additional impacts to soils, vegetation, and growth (Additional Impact Analysis).

The “Billings Projects for 2022” emission increases are above the significant emission rates listed in ARM 17.8.801(28) for PM<sub>10</sub>, PM<sub>2.5</sub>, and NO<sub>x</sub> and warrant further analyses. Emission increases were first modeled to determine if any model receptors exceeded the Significant Impact Levels (SILs), presented in Table V-1. For those pollutant and averaging times that exceed the applicable SILs, Phillips 66 was required to demonstrate compliance with NAAQS, MAAQS, and PSD Increments, also presented in Table V-1. For this project, PM<sub>2.5</sub> annual, PM<sub>2.5</sub> 24-hour, and NO<sub>2</sub> 1-hour Class II SILs were exceeded, which then required NAAQS, MAAQS and Class II Increment analyses for applicable pollutants and respective averaging periods.

**Table V-1 Applicable standards**

Pollutant	Averaging Period	Class I SIL ( $\mu\text{g}/\text{m}^3$ )	Class II SIL ( $\mu\text{g}/\text{m}^3$ )	Primary NAAQS ( $\mu\text{g}/\text{m}^3$ )	MAAQS ( $\mu\text{g}/\text{m}^3$ )	Class I Increment ( $\mu\text{g}/\text{m}^3$ )	Class II Increment ( $\mu\text{g}/\text{m}^3$ )	SMC ( $\mu\text{g}/\text{m}^3$ )
PM <sub>10</sub>	24-hour	0.3	5	150	150	8	30	10
	Annual	0.2	1	-	50	4	17	-
PM <sub>2.5</sub>	24-hour	0.27	1.2	35	-	2	9	-
	Annual	0.051	0.2	12	-	1	4	-
NO <sub>2</sub>	1-hour	-	7.5	188	564	-	-	-
	Annual	0.1	1	100	94	2.5	25	14
O <sub>3</sub>	1-hour	-	-	-	196	-	-	-
	8-hour	-	1.96	137	-	-	-	-

The SIL, Increment, and MAAQS/NAAQS compliance demonstrations were conducted using the latest available version of EPA-approved American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) and associated preprocessors. Specifically:

- AERMOD version 19191: Air dispersion model.
- AERMET version 19191: processes NWS meteorological data for input to AERMOD.
- AERMINUTE version 15272: processes 1-minute NWS wind data to generate hourly average winds for input to AERMET.
- AERSURFACE version 13016: processes 1992 National Land Cover Data surface characteristics for input to AERMET.
- AERMAP version 18081: Processes National Elevation Data from the USGS to determine elevation of sources and receptors for input into AERMOD.
- BPIPFRM version 04274: characterizes building downwash for input to AERMOD.
- Lakes Environmental Software, Inc. AERMOD VEW version 9.9.0.

Regulatory default options were used for all model runs. Rural dispersion coefficients were applied, as all of Montana currently meets this criterion. All buildings at the site were evaluated for building downwash on each modeled point source, using BPIPFRM.

Five years of meteorological data (2015-2019) ready for use in AERMOD was constructed using representative surface and upper air data. Surface air data was obtained from the closest National Weather Service (NWS) station, which is located approximately 4 km to the north-northwest of the project site, at the Billings Logan International Airport (KBIL – WMO 726770, WBAN 24033). This NWS station also provided the automated surface observing system (ASOS) one-minute data used with AERMINUTE. The Great Falls Upper Air station (WMO 72776, WBAN 04102) was used for upper air data. The ADJ\_U\* option was employed in AERMET to account for stable, low wind speeds.

A series of three nested receptor grids were used in the model to calculate the ambient air impacts around the project location. Discrete receptors were placed at 100 m spacing along the site's fence line, 100 m spacing from the site's fence line to 1 km from the site, 250 m spacing from 1 km to 3 km from the site, and 500 m spacing from 3 km to 10 km from the site, totaling 8590 receptor locations. Only the significantly impacted receptors (receptors

with modeled concentrations equal to or greater than their respective SILs) were used for the NAAQS/MAAQs and applicable Increment analyses.

The source and building elevations at the site were based on the existing graded elevation. Receptor elevations and regional inventory source elevations were determined using the terrain preprocessor AERMAP and elevation data based on 1/3 arc-second (approximately 10 m resolution) National Elevation Dataset (NED) from the United States Geological Survey (USGS).

The following PM<sub>2.5</sub> and NO<sub>2</sub> monitoring sites were identified for use as background concentrations and to determine PM<sub>2.5</sub> SIL applicability. The PM<sub>2.5</sub> data was stitched together from two sites in Billings, the St. Lukes monitor (30-111-0085) from January 2017 through December 2017, and the Lockwood monitor (30-111-0087) from December 2017 through December 2019. The background concentrations were calculated both including and excluding exceptional events (wildfires, windblown dust, etc.), to illustrate the impacts of wildfires on the background levels, and are displayed in Table V-2.

As a conservative approach, for NO<sub>2</sub>, monitoring data from 2008 from the Shepherd site was used as a background concentration. This data is notably dated and was not collected over an entire three-year period; however, based on review of emissions inventory data, emissions from mobile and stationary sources were higher in 2008 than today. In addition to significant reductions in mobile source NO<sub>x</sub> emissions with time, significant reductions from stationary sources have also occurred, most notably, Corette, a power plant with over 1,700 tons of NO<sub>x</sub> emissions in 2008, no longer emits any NO<sub>x</sub> emissions. The 2008 National Emission Inventory (NEI) cites approximately 11,236 tons total NO<sub>x</sub> emissions in Yellowstone County while the 2017 NEI (latest available) cites approximately 8,750 tons. It should also be noted that although large reductions in stationary source emissions are present when comparing 2008 to today, the monitor was not sited directly in the typical path of the stationary source emissions which were reduced, based on airport wind patterns. Therefore, the monitor is believed to provide a conservative but reasonable background concentration to add to modeled impacts in assessing NAAQS/MAAQs compliance, providing a reasonable representation of background emissions in the Billings area for purposes of this permitting action. It should also be noted that review of Phillips 66's emissions confirms that emissions of NO<sub>x</sub> were higher during this period than the selected baseline emissions period of 2018 and 2019; therefore, the emissions increases modeled, when compared temporally to the 2008 background monitor data, are also conservative.

**Table V-2 PM<sub>2.5</sub> Background concentrations**

<b>Pollutant</b>	<b>Averaging Time</b>	<b>Background Conc. (µg/m<sup>3</sup>)<sup>(1)</sup></b>	<b>Background Conc. (µg/m<sup>3</sup>)<sup>(2)</sup></b>	<b>Basis</b>	<b>Site</b>
PM <sub>2.5</sub>	24-hour	22.9	14.7	Avg. 98% ile of yearly 24-hour values	Billings – St. Lukes (30-111- 0085) and Lockwood (30- 111-0087)
	Annual	7.4	6.4	3-year Annual avg.	
NO <sub>2</sub>	1-hour	-	54.6 (29 ppb)	Avg 98% of daily 1- hour max	Shepherd (30-111- 0086) (years: 2005- 2007)

	Annual	-	6.7 (3.6 ppb)	3-year Annual avg.
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<sup>(1)</sup>Data includes all exceptional event data in the calculations.

<sup>(2)</sup>Data excludes all exceptional event data in the calculations.

Data with exceptional events removed was used for all purposes in this analysis. The background concentrations are added to the modeled concentrations in the NAAQS analysis. The data, representative of the Billings metropolitan area fulfills the preconstruction and post-construction monitoring requirements of ARM 17.8.822. As presented further in the analysis, Ramboll demonstrated that PM<sub>10</sub> and NO<sub>2</sub> pre-construction and post-construction monitoring requirements of Subchapter 8 may be waived due to the modeled impacts from the PM<sub>10</sub> and NO<sub>2</sub> emissions increases being less than the significant monitoring concentration (SMCs), which are displayed in ARM 17.8.818(7)(a)(ii).

Secondary PM<sub>2.5</sub> impacts consisting primarily of NO<sub>x</sub> and SO<sub>2</sub> precursor emissions due to the project cannot be evaluated with the AERMOD dispersion model since it cannot take chemical transformations into account. Phillips 66 assessed secondary PM<sub>2.5</sub> formation using hypothetical source precursor pollutant (NO<sub>x</sub> and SO<sub>2</sub>) emission rate data and secondary PM<sub>2.5</sub> photochemical modeling results that were utilized by the EPA to develop Modeled Emission Rates for Precursors (MERPs) for NO<sub>x</sub> and SO<sub>2</sub>. Photochemical modeling results for the appropriate hypothetical source's three emission rates and a linear fit was used to determine the PM<sub>2.5</sub> impacts for both 24-hour and annual emission increases of NO<sub>x</sub> and SO<sub>2</sub>. These impacts were added to all PM<sub>2.5</sub> AERMOD modeling results, as displayed in the applicable tables below.

Ozone impacts due to NO<sub>x</sub> and VOC precursors emissions due to the project also cannot be evaluated with the AERMOD dispersion model since it cannot take chemical transformations into account. Phillips 66 assessed ozone formation using hypothetical source precursor pollutant (NO<sub>x</sub> and VOC) emission rate data and ozone photochemical modeling results that were utilized by the EPA to develop MERPs for NO<sub>x</sub> and VOC.

For the NO<sub>2</sub> modeling analyses, Tier 2 (Ambient Ratio Method, ARM2) was employed in AERMOD, with the EPA default minimum and maximum ambient ratios of 0.5 and 0.9, respectively (ratio of NO<sub>2</sub>/NO<sub>x</sub>).

Source parameters were provided by Phillips 66, all parameters were "point" sources in AERMOD and their descriptions are displayed in Table V-3. Three separate scenarios were run for Jupiter's two stacks, average elemental sulfur/average ATS production mode ("Average"), maximum elemental sulfur production mode ("Max S"), and maximum ATS production mode ("Max ATS"). The differences of these three modes are reflected in the stack velocity and temperature.

**Table V-3 Onsite Source Descriptions**

SrcID	Source Description	Source Category
P_3	Loading Rack VCU	Other Existing Source
P_51_54	Boiler House (B-1, B-2, B-5, & B-6) Stack	Other Existing Source
P_55	Temporary Boiler	Other Existing Source
P_56	Small Crude Unit Heater (H-1)	NO <sub>x</sub> Only Contemporaneous Source

P_61	No. 2 HDS Heater (H-10)	Other Existing Source
P_62	No. 2 HDS Debutanizer Reboiler (H-11)	Other Existing Source
P_63	No. 2 HDS Main Fractionator Reboiler (H-12)	Other Existing Source
P_64	Catalytic Reforming Unit #2 (H-13)	Project-Impacted Source
P_65	Catalytic Reforming Unit #2 (H-14)	Project-Impacted Source
P_67	Sat Gas Stabilizer Reboiler (H-16)	Project-Impacted Source
P_68OLD	Vacuum Furnace (H-17) - OLD	NO <sub>x</sub> Only Contemporaneous Source
P_68NEW	Vacuum Furnace (H-17) - NEW	NO <sub>x</sub> Only Contemporaneous Source
P_69	FCCU Preheater (H-18)	NO <sub>x</sub> : Project-Impacted Source and Contemporaneous Source; PM <sub>2.5</sub> : Project-Impacted Source
P_70	Butamer Heater (H-20)	Other Existing Source
P_71	Alky Heater (H-21)	Project-Impacted Source
P_72	Catalytic Reforming Unit #2 (H-23)	Project-Impacted Source
P_73	Large Crude Unit Heater (H-24)	NO <sub>x</sub> Only Contemporaneous Source
P_74	Coker Furnace (H-3901)	Project-Impacted Source
P_75	No. 4 HDS Recycle Hydrogen Heater (H-8401)	NO <sub>x</sub> : Project-Impacted Source and Contemporaneous Source; PM <sub>2.5</sub> : Project-Impacted Source
P_76	No. 4 HDS Fractionator Feed Heater (H-8402)	NO <sub>x</sub> : Project-Impacted Source and Contemporaneous Source; PM <sub>2.5</sub> : Project-Impacted Source
P_77	No. 1 H2 Plant Reformer Heater (H-9401)	NO <sub>x</sub> Only Contemporaneous Source
P_78	No. 5 HDS Charge Heater (H-9501)	NO <sub>x</sub> : Project-Impacted Source and Contemporaneous Source; PM <sub>2.5</sub> : Project-Impacted Source
P_79	No. 5 HDS Stabilizer Reboiler Heater (H-9502)	NO <sub>x</sub> : Project-Impacted Source and Contemporaneous Source; PM <sub>2.5</sub> : Project-Impacted Source

P_80	No. 2 H2 Plant Reformer Heater (H-9701)	NO <sub>x</sub> Only Contemporaneous Source
P_81	Flare	Other Existing Source
P_82	Jupiter Flare	Other Existing Source
P_83	Jupiter Main Stack No. 1	NO <sub>x</sub> : Modified Source and Contemporaneous Source; PM <sub>2.5</sub> : Modified Source
P_85	Jupiter Main Stack No. 2	NO <sub>x</sub> : Modified Source and Contemporaneous Source; PM <sub>2.5</sub> : Modified Source
P_86	FCCU Stack	NO <sub>x</sub> : Modified Source and Contemporaneous Source; PM <sub>2.5</sub> : Modified Source
P_87	Cooling Tower - Combination Unit	Other Existing Source
P_88	Cooling Tower - Condensate Unit	Other Existing Source
P_89	Cooling Tower (CWT-5)	Other Existing Source
P_90	Jupiter Cooling Tower (CT-615A/B/C)	Other Existing Source
P_91	Jupiter Cooling Tower (CT-120)	Other Existing Source
P_92	Jupiter Cooling Tower (CT-602)	Other Existing Source
P_141_1	Coke Handling	Project-Impacted Source
P_141_2	Delayed Coking Unit - Vent, Coke Cutting, and Water Handling	Project-Impacted Source
P_143_1	Backup Coke Crusher Diesel Engine	Other Existing Source
P_143_2	Boiler House Backup Air Compressor Engine	NO <sub>x</sub> Only Contemporaneous Source
P_143_3	Coker Backup Air Compressor Engine	NO <sub>x</sub> Only Contemporaneous Source
P_143_4	Flare Drum Backup Pump Engine	NO <sub>x</sub> Only Contemporaneous Source
P_143_5	P400 E Diesel Firewater Pump at Ponds	Other Existing Source
P_143_6	P491 Cooling Tower Water to Fire Water	Other Existing Source
P_143_7	P4701 W Diesel Firewater Pump at Ponds	Other Existing Source
P_143_8	Boilerhouse Emergency Diesel Generator	Other Existing Source
P_143_9	MCC7 Emergency Diesel Generator	Other Existing Source
P_143_10	P510 Storm Water Sump to Holding Pond	Other Existing Source
P_143_11	Blender Research Octane Knock Engine	Other Existing Source
P_143_12	Blender Motor Octane Knock Engine	Other Existing Source
P_143_13	Main Lab Research Octane Knock Engine	Other Existing Source
P_143_14	Main Lab Motor Octane Knock Engine	Other Existing Source
P_164	No. 3 H2 Plant Reformer Heater H-8501	New Source
P_165	New Jupiter Cooling Tower	New Source

PSD Class II Air Quality Analysis

In addition to use as background data, Phillips 66 justified the SILs use by demonstrating that the PM<sub>2.5</sub> SILs added to the background are less than the applicable NAAQS. PM<sub>10</sub> and PM<sub>2.5</sub> emissions increases at the project site were modeled and compared to applicable SILs. The annual, 24-hour, and 1-hour (as applicable) emissions increases are provided in Table V-4. New sources were given their potential to emit emission rate, modified sources were given actual-to-potential emission rates, shutdown sources negative emissions, project impacted sources and contemporaneous sources were given incremental emission rate increase or actual-to-potential emissions increases, as applicable. These model runs also determined which of the three operating scenarios for the Jupiter stacks created the highest impacts, and those scenarios were retained for further cumulative analyses, as applicable.

**Table V-4 SIL Modeled Emissions Increases**

SrcID	PM <sub>10</sub> 24-hour (lb/hr)	PM <sub>10</sub> Annual (tpy)	PM <sub>2.5</sub> 24-hour (lb/hr)	PM <sub>2.5</sub> Annual (tpy)	NO <sub>2</sub> 1-hour (lb/hr)	NO <sub>2</sub> Annual (tpy)
P_56	0.000	0.000	0.000	0.000	1.242	5.440
P_64	0.003	0.014	0.002	0.010	0.105	0.460
P_65	0.001	0.006	0.001	0.004	0.041	0.180
P_67	0.003	0.015	0.002	0.010	0.107	0.470
P_68OLD	0.000	0.000	0.000	0.000	-3.952	-17.310
P_68NEW	0.000	0.000	0.000	0.000	2.251	9.860
P_69	0.034	0.150	0.023	0.100	1.820	7.970
P_71	0.023	0.100	0.016	0.070	0.747	3.270
P_72	0.003	0.015	0.002	0.010	0.107	0.470
P_73	0.000	0.000	0.000	0.000	-3.505	-15.350
P_74	0.022	0.095	0.015	0.066	0.397	1.740
P_75	0.007	0.031	0.005	0.022	0.436	1.910
P_76	0.007	0.032	0.005	0.022	0.158	0.690
P_77	0.000	0.000	0.000	0.000	5.966	26.130
P_78	0.004	0.017	0.003	0.012	0.112	0.490
P_79	0.008	0.033	0.005	0.023	0.219	0.960
P_80	0.000	0.000	0.000	0.000	0.858	3.760
P_83 <sup>(1)</sup>	3.194	13.990	3.194	13.990	2.236	9.795
P_85 <sup>(1)</sup>	3.194	13.990	3.194	13.990	14.840	9.795
P_86	0.863	3.780	0.863	3.780	2.669	11.690
P_92	-0.008	-0.033	-0.008	-0.033	NA	NA
P_141_1	0.011	0.049	0.005	0.022	NA	NA
P_141_2	0.009	0.039	0.009	0.039	NA	NA
P_143_2	0.000	0.000	0.000	0.000	0.000	0.090
P_143_3	0.000	0.000	0.000	0.000	0.000	0.090
P_143_4	0.000	0.000	0.000	0.000	0.000	0.990
P_164	0.349	1.530	0.240	1.050	4.590	17.480

P_165	0.062	0.270	0.062	0.270	NA	NA
<b>Total:</b>		<b>34.122</b>		<b>33.457</b>		<b>81.070</b>

<sup>(1)</sup>For both PM pollutants, “Max ATS” scenario was determined to produce the highest impacts for the 24-hour averaging model run; “Ave” for the annual averaging model run. For NO<sub>2</sub>, “Max ATS” produced the highest impacts for both averaging periods.

Modeled PM<sub>10</sub>, PM<sub>2.5</sub>, and NO<sub>2</sub> Class II SIL results are presented in Table V-5. PM<sub>2.5</sub> impacts exceeded the 24-hour and Annual SILs, therefore a NAAQS and Class II Increment analyses were performed. NO<sub>2</sub> 1-hour SILs were exceeded, therefore NAAQS and MAAQS analyses were performed. For the pollutants exceeding the SIL, the significant impact area (SIA) was determined, which was the furthest distance of the modeled SIL-exceeded receptor from the source.

**Table V-5 Class II Significant Impact Analysis Results**

Pollutant	Avg. Period	Model Conc. (µg/m <sup>3</sup> )	Secondary Impact Conc. (µg/m <sup>3</sup> )	Total Conc. (µg/m <sup>3</sup> )	SIL (µg/m <sup>3</sup> )	SIA (km)
PM <sub>10</sub>	24-hour	3.4 <sup>(1)</sup>	-	3.4	5	-
	Annual	0.3 <sup>(2)</sup>	-	0.3	1	-
PM <sub>2.5</sub>	24-hour	2.72 <sup>(3)</sup>	0.035	2.8	1.2	1.78
	Annual	0.25 <sup>(4)</sup>	0.0007	0.3	0.2	1.79
NO <sub>2</sub>	1-hour	86.8 <sup>(5)</sup>	-	86.8	7.5	17.01
	Annual	0.9 <sup>(2)</sup>	-	0.9	1	-
O <sub>3</sub>	8-hour	0.19 <sup>(6)</sup>	-	0.19	1.96	-

<sup>(1)</sup>Modeled concentration is the maximum 24-hour concentration in a 5-year period.

<sup>(2)</sup>Modeled concentration is the maximum annual concentration in a 5-year period.

<sup>(3)</sup>Modeled concentration is the maximum 5-year average 24-hour concentration.

<sup>(4)</sup>Modeled concentration is the maximum 5-year average annual concentration.

<sup>(5)</sup>Modeled concentration is the maximum 5-year average of the maximum daily 1-hour concentration.

<sup>(6)</sup>Concentration estimated using EPA’s MERPs tool.

#### NAAQS/MAAQS Air Quality Analysis

For NAAQS and Increment analyses, offsite source emissions within the SIA were included. Additionally, sources located outside of the SIA were screened for potential exclusion based on the “20D” procedure. Sources outside the SIA were excluded if the facility-wide emissions (tons per year, 2018 and 2019 actual averages) are less than 20 times the distance (km) from the facility to the nearest edge of the SIA for annual averaging periods. For the shorter averaging periods, sources were excluded if the facility-wide emissions (tons per year) were less than 20 times the distance (km) from the source to the site. Ramboll performed this analysis with emissions data provided by MT DEQ, which resulted in the inclusion of several sources. Many of the provided sources were included for NO<sub>2</sub>, which had a 17 km SIA. For PM<sub>2.5</sub>, it was determined that the inclusion of the relatively fewer offsite source emissions was sufficient (1.2 km SIA for 24-hour period), as the location of the Lockwood PM<sub>2.5</sub> background monitor captures influences from any excluded sources, due to the dominant wind direction from the southwest. The offsite source descriptions are shown in Table V-6.

**Table V-6 Offsite Source Descriptions**

SrcID	Source Description
OFFSTE1	EXXONMOBIL BILLINGS REFINERY - COKER/CO BOILER
OFFSTE2	EXXONMOBIL BILLINGS REFINERY - F-10 COKER FEED
OFFSTE3	EXXONMOBIL BILLINGS REFINERY - F-1201 CATALYTIC HYDROFINING UNIT
OFFSTE4	EXXONMOBIL BILLINGS REFINERY - F-2 CRUDE/VAC UNIT
OFFSTE5	EXXONMOBIL BILLINGS REFINERY - F-201 HYDROFINER
OFFSTE6	EXXONMOBIL BILLINGS REFINERY - F-3 CRUDE UNIT
OFFSTE7	EXXONMOBIL BILLINGS REFINERY - F-3X HYDROFINER
OFFSTE8	EXXONMOBIL BILLINGS REFINERY - F-402 ALKYLATION UNIT
OFFSTE9	EXXONMOBIL BILLINGS REFINERY - F-5 HYDROFINER
OFFSTE10	EXXONMOBIL BILLINGS REFINERY - F-551 HYDROGEN PLANT
OFFSTE11	EXXONMOBIL BILLINGS REFINERY - F-651 HYDROCRACKER
OFFSTE12	EXXONMOBIL BILLINGS REFINERY - F-700 POWERFORMER
OFFSTE13	EXXONMOBIL BILLINGS REFINERY - FCC/CO BOILER
OFFSTE14	EXXONMOBIL BILLINGS REFINERY - FLARE
OFFSTE15	EXXONMOBIL BILLINGS REFINERY - FUGITIVE VOC EMISSIONS
OFFSTE16	EXXONMOBIL BILLINGS REFINERY - INSIGNIFICANT SOURCES
OFFSTE17	EXXONMOBIL BILLINGS REFINERY - SE14: 600HP DIESEL BACKUP ENGINE
OFFSTE18	EXXONMOBIL BILLINGS REFINERY - STANDBY BOILER HOUSE
OFFSTE19	MONTANA SULPHUR & CHEMICAL - 17MM BTU/HR BOILER
OFFSTE20	MONTANA SULPHUR & CHEMICAL - CLAUS PLANTS
OFFSTE21	MONTANA SULPHUR & CHEMICAL - CLEAVER BROOKS BOILER
OFFSTE22	YELLOWSTONE POWER PLANT - CFB BOILERS
OFFSTE27	BILLINGS BAKERY - BOILER #1 - NAT GAS FIRED CLEAVER BROOKS BOILER CB-200-150
OFFSTE28	BILLINGS BAKERY - BOILER #2 - NAT GAS FIRED CLEAVER BROOKS BOILER CB-200-150
OFFSTE29	BILLINGS BAKERY - BREAD OVEN BURNER - NATURAL GAS FIRED
OFFSTE30	BILLINGS BAKERY - ROLL OVEN BURNER - NATURAL GAS FIRED
OFFSTE31	CREMATION & FUNERAL GALLERY - B AND L CREMATION - 1996
OFFSTE32	CITY OF BILLINGS ANIMAL SHELTER - CREMATORIUM
OFFSTE33	A TREASURED FRIEND CREMATORY AND MONUMENT COMPANY - CREMATORIUM
OFFSTE34	WASTEWATER PLANT - AMERICAN STANDARD
OFFSTE35	WASTEWATER PLANT - BURNHAM BOILER
OFFSTE36	WASTEWATER PLANT - CLEAVER BROOKS
OFFSTE37	WASTEWATER PLANT - CUMMINS GENERATOR
OFFSTE38	WASTEWATER PLANT - EMERGENCY BACK-UP GENERATOR
OFFSTE39	WASTEWATER PLANT - FLARE
OFFSTE41	DAHL FUNERAL CHAPEL BILLINGS INC - CREMATORIUM
OFFSTE42	YELLOWSTONE VALLEY VETERINARY INC - ANIMAL CREMATORY #1

OFFSTE43	BILLINGS LANDFILL GAS PRODUCTION FACILITY - FLARE
OFFSTE44	BILLINGS LANDFILL GAS PRODUCTION FACILITY - LANDFILL GAS ENGINE #1
OFFSTE45	BILLINGS LANDFILL GAS PRODUCTION FACILITY - TO FLARE
OFFSTE46	HEIGHTS FAMILY FUNERAL HOME AND CREMATORY - CREMATORIUM
OFFSTE47	BEST FRIENDS ANIMAL HOSPITAL - CREMATORIIUMS - ANIMAL AND/OR HUMAN
OFFSTE23	WESTERN SUGAR COOPERATIVE - BOILER #1 (ERIE CITY)
OFFSTE24	WESTERN SUGAR COOPERATIVE - BOILER #2, 3, 4 (RILEY COAL)
OFFSTE25	WESTERN SUGAR COOPERATIVE - EAST PULP DRYER
OFFSTE26	WESTERN SUGAR COOPERATIVE - WEST PULP DRYER
WSC_B5	WESTERN SUGAR COOPERATIVE - BOILER #5 - NATRL GAS
WSC_PC	WESTERN SUGAR COOPERATIVE - PELLETIZER-COOLER
WSC_BF	WESTERN SUGAR COOPERATIVE - BEET UNLOAD/HANDLE FUGTVS
WSC_CLF	WESTERN SUGAR COOPERATIVE - COAL UNLOAD/HANDLE FUGTVS
WSC_WE	WESTERN SUGAR COOPERATIVE - EXPOSED AREA - WIND EROSN
WSC_KC	WESTERN SUGAR COOPERATIVE - KILN LIMESTONE/COKE TRANSFER
WSC_LF	WESTERN SUGAR COOPERATIVE - LIMESTONE UNLOAD/HNDL FUG

New, modified, project-impacted, and contemporaneous sources used potential to emit emission rates; other existing sources (including offsite) were given actual emissions appropriate to each averaging period, averaged over 2018 and 2019. These emissions rates are displayed in Table V-7.

**Table V-7 Modeled Emissions for NAAQS Analysis**

SrcID	PM <sub>2.5</sub> 24-hour (lb/hr)	PM <sub>2.5</sub> Annual (tpy)	NO <sub>2</sub> 1-hour (lb/hr)
P_3	0.000	0.000	0.147
P_51_54	1.767	7.740	31.320
P_55	0.000	0.000	0.000
P_56	0.071	0.310	1.680
P_61	0.043	0.190	2.000
P_62	0.080	0.350	3.750
P_63	0.158	0.690	7.270
P_64	0.091	0.400	4.210
P_65	0.034	0.150	1.620
P_67	0.094	0.410	4.310
P_68NEW	0.126	0.550	2.250
P_69	0.162	0.710	7.550
P_70	0.005	0.020	0.220
P_71	0.128	0.560	5.980

P_72	0.094	0.410	4.310
P_73	0.206	0.900	4.330
P_74	0.263	1.150	4.980
P_75	0.066	0.290	0.730
P_76	0.066	0.290	0.760
P_77	0.543	2.380	10.750
P_78	0.053	0.230	0.750
P_79	0.103	0.450	1.470
P_80	0.331	1.450	5.730
P_81	0.000	0.001	0.330
P_82	0.000	0.001	0.003
P_83 <sup>(1)</sup>	4.000	17.520	14.840
P_85 <sup>(1)</sup>	4.000	17.520	14.840
P_86	10.811	47.350	25.230
P_87	1.571	6.880	0.000
P_88	1.089	4.770	0.000
P_89	0.089	0.390	0.000
P_90	0.094	0.410	0.000
P_91	0.139	0.610	0.000
P_92	0.000	0.000	0.000
P_141_1	0.050	0.220	0.000
P_141_2	0.027	0.120	0.000
P_143_1	0.002	0.010	0.004
P_143_2	0.000	0.002	0.000
P_143_3	0.000	0.002	0.000
P_143_4	0.011	0.050	0.000
P_143_5	0.001	0.004	0.000
P_143_6	0.003	0.015	0.000
P_143_7	0.001	0.003	0.000
P_143_8	0.001	0.005	0.000
P_143_9	0.000	0.001	0.000
P_143_10	0.001	0.002	0.008
P_143_11	0.005	0.020	0.066
P_143_12	0.005	0.020	0.066
P_143_13	0.005	0.020	0.066
P_143_14	0.005	0.020	0.066
P_164	0.240	1.050	4.590
P_165	0.062	0.270	NA
OFFSTE1	NA	NA	41.768
OFFSTE2	NA	NA	0.000
OFFSTE3	NA	NA	2.335
OFFSTE4	NA	NA	22.177
OFFSTE5	NA	NA	2.110

OFFSTE6	NA	NA	2.979
OFFSTE7	NA	NA	3.309
OFFSTE8	NA	NA	2.819
OFFSTE9	NA	NA	2.387
OFFSTE10	NA	NA	14.024
OFFSTE11	NA	NA	5.335
OFFSTE12	NA	NA	2.213
OFFSTE13	NA	NA	10.715
OFFSTE14	NA	NA	3.143
OFFSTE15	NA	NA	14.467
OFFSTE16	NA	NA	0.011
OFFSTE17	NA	NA	0.022
OFFSTE18	NA	NA	0.918
OFFSTE19	NA	NA	0.240
OFFSTE20	NA	NA	0.759
OFFSTE21	NA	NA	0.388
OFFSTE22	NA	NA	298.791
OFFSTE27	NA	NA	0.097
OFFSTE28	NA	NA	0.074
OFFSTE29	NA	NA	0.097
OFFSTE30	NA	NA	0.074
OFFSTE31	NA	NA	0.023
OFFSTE32	NA	NA	0.003
OFFSTE33	NA	NA	0.000
OFFSTE34	NA	NA	0.110
OFFSTE35	NA	NA	0.095
OFFSTE36	NA	NA	0.004
OFFSTE37	NA	NA	0.069
OFFSTE38	NA	NA	0.006
OFFSTE39	NA	NA	0.066
OFFSTE41	NA	NA	0.007
OFFSTE42	NA	NA	0.005
OFFSTE43	NA	NA	0.330
OFFSTE44	NA	NA	1.857
OFFSTE45	NA	NA	0.531
OFFSTE46	NA	NA	0.008
OFFSTE47	NA	NA	0.005
OFFSTE23	0.130	0.570	4.795
OFFSTE24	1.462	6.404	44.590
OFFSTE25	0.237	1.040	0.537
OFFSTE26	0.054	0.238	0.080
WSC_PC	0.040	0.174	NA
WSC_BF	0.219	0.958	NA

WSC_CLF	0.000	0.000	NA
WSC_WE	0.228	1.000	NA
WSC_KC	0.131	0.575	NA
WSC_LF	0.143	0.628	NA

<sup>(1)</sup>For PM<sub>2.5</sub>, “Max ATS” scenario was determined to produce the highest impacts for the 24-hour averaging model run; “Ave” for the annual averaging model run. For NO<sub>2</sub> 1-hour “Max ATS” produced the highest impacts.

The results of the NAAQS analysis are shown in Table V-8, which show that the modeled emissions comply with both PM<sub>2.5</sub> and NO<sub>2</sub> 1-hour NAAQS standards.

**Table V-8 NAAQS Analysis Results**

Pollutant	Avg. Period	Model Design Value (µg/m <sup>3</sup> )	Secondary Impact Conc. (µg/m <sup>3</sup> )	Monitor Design Value (µg/m <sup>3</sup> )	Total Conc. (µg/m <sup>3</sup> )	Primary NAAQS (µg/m <sup>3</sup> )	% of NAAQS
PM <sub>2.5</sub>	24-hour	1.65 <sup>(1)</sup>	0.035	14.7	16.4	35	47%
	Annual	0.54 <sup>(2)</sup>	0.0007	6.4	6.9	12	58%
NO <sub>2</sub>	1-hour	102.8 <sup>(3)</sup>	-	54.6	157.4	188	84%

<sup>(1)</sup>The receptor that had the 8th-highest 24-hr value per year, averaged over 5 years.

<sup>(2)</sup>The receptor that had the maximum annual value averaged across 5 years.

<sup>(3)</sup>The receptor that had the 8th-highest daily 1-hr max value averaged over 5 years.

A demonstration of compliance with applicable MAAQS (ARM 17.8 Subchapter 2), displayed in Table V1-1, was performed for the 1-hour NO<sub>2</sub> standard, due to the modeled exceedance of the 1-hour NO<sub>2</sub> SIL. Since the form of the standard is not to be exceeded more than once per year, it was conservatively assessed as the highest-first-high from the 1-hour NO<sub>2</sub> NAAQS to demonstrate that the project will not cause or contribute to an exceedance of the 1-hour NO<sub>2</sub> MAAQS. The results are displayed in Table V-9.

**Table V-9 NO<sub>2</sub> MAAQS Analysis Results**

Pollutant	Avg. Period	Model Design Value (µg/m <sup>3</sup> )	Secondary Impact Conc. (µg/m <sup>3</sup> )	Monitor Design Value (µg/m <sup>3</sup> )	Total Conc. (µg/m <sup>3</sup> )	Primary MAAQS (µg/m <sup>3</sup> )	% of NAAQS
NO <sub>2</sub>	1-hour	166.3 <sup>(1)</sup>	-	54.6	220.9	564	39%

<sup>(1)</sup>The receptor that had the maximum 5-year average of the highest daily maximum 1-hour concentration.

#### PSD Class II Increment Air Quality Analysis

A PSD increment analysis was conducted to demonstrate compliance with the PM<sub>2.5</sub> PSD Class II increments, as specified in ARM 17.8.804. The major source baseline date for PM<sub>2.5</sub>, as specified in ARM 17.8.801(21), is October 20, 2010. The minor source baseline date is the earliest date after the trigger date (October 20, 2011) on which a major stationary source submits a complete PSD application; in this case September 16, 2015.

New, modified, project-impacted, and contemporaneous sources’ emissions and selected offsite emissions were modeled. Most offsite source emissions were calculated by

subtracting an average of its 2013 and 2014 annual emission rates from an emission rate equal to an average of its 2018 and 2019 emission rates. These emission rates are displayed in Table V-10.

**Table V-10 Modeled PM<sub>2.5</sub> Emissions for Class II Increment Analysis**

SrcID	24-hour emissions (lb/hr)	Annual emissions (tpy)
P_51_54	0.621	2.720
P_55	0.000	0.000
P_56	-0.002	-0.010
P_61	-0.002	-0.010
P_62	-0.011	-0.050
P_63	0.023	0.100
P_64	0.091	0.400
P_65	0.034	0.150
P_67	0.094	0.410
P_68OLD	-0.290	-1.270
P_68NEW	0.126	0.550
P_69	0.162	0.710
P_70	0.000	0.002
P_71	0.128	0.560
P_72	0.094	0.410
P_73	0.037	0.160
P_74	0.263	1.150
P_75	0.066	0.290
P_76	0.066	0.290
P_77	0.142	0.620
P_78	0.053	0.230
P_79	0.103	0.450
P_80	0.005	0.020
P_81	0.000	0.000
P_82	0.000	0.000
P_83 <sup>(c)</sup>	4.000	17.520
P_85 <sup>(c)</sup>	4.000	17.520
P_86	10.811	47.350
P_87	1.571	6.880
P_88	1.089	4.770
P_89	0.089	0.390
P_90	0.094	0.410
P_91	0.139	0.610
P_92	0.000	0.000
P_141_1	0.050	0.220
P_141_2	0.027	0.120
P_143_1	-0.003	-0.011

P_143_2	0.000	0.002
P_143_3	0.000	0.002
P_143_4	0.011	0.050
P_143_5	-0.003	-0.011
P_143_6	-0.003	-0.011
P_143_7	-0.003	-0.011
P_143_8	-0.003	-0.011
P_143_9	-0.003	-0.011
P_143_10	-0.003	-0.011
P_143_11	0.000	-0.002
P_143_12	0.000	-0.002
P_143_13	0.000	-0.002
P_143_14	0.000	-0.002
P_164	0.240	1.050
P_165	0.062	0.270
OFFSTE23	0.128	0.561
OFFSTE24	-1.193	-5.226
OFFSTE25	0.033	0.145
OFFSTE26	-0.670	-2.933
WSC_B5	-0.001	-0.004
WSC_PC	-0.055	-0.240
WSC_BF	-0.001	-0.007
WSC_CLF	0.000	0.000
WSC_WE	0.000	0.000
WSC_KC	0.003	0.012
WSC_LF	0.004	0.018

<sup>(1)</sup>“Max ATS” scenario was determined to produce the highest impacts for the 24-hour averaging model run; “Ave” for the annual averaging model run.

The results of the Class II Increment analysis are displayed in Table V-11, and show compliance with both averaging periods.

**Table V-11 PM<sub>2.5</sub> Class II Increment Analysis Results**

<b>Averaging Period</b>	<b>Model Conc. (µg/m<sup>3</sup>)</b>	<b>Secondary Impact Conc. (µg/m<sup>3</sup>)</b>	<b>Total Conc. (µg/m<sup>3</sup>)</b>	<b>Class II Increment (µg/m<sup>3</sup>)</b>	<b>% of Increment</b>
24-hour	4.54 <sup>(1)</sup>	0.035	4.6	9	51%
Annual	0.45 <sup>(2)</sup>	0.0007	0.5	4	13%

<sup>(1)</sup>The receptor that had the maximum second highest 24-hour concentration in any of the 5 year period.

<sup>(2)</sup>The receptor that had the maximum annual concentration in any of the 5 years.

PSD Class I Air Quality Analysis

A significant impact analysis was performed to evaluate whether the project’s net emissions increases of PM<sub>10</sub>, PM<sub>2.5</sub>, and NO<sub>2</sub> would indicate a modeled impact in the area near the site that would exceed applicable PSD Class I SILs. Receptors were placed in a circle at 50 km from the project site, and the maximum modeled impact at this 50 km arc was compared to the applicable Class I SIL. All nearby Class I areas are located greater than 100 km from the site. Modeled emissions increases were the same as those shown in Table V-4. The “Max ATS” scenario produced the highest 24-hour and annual results for both PM<sub>10</sub> and PM<sub>2.5</sub>. The results of this analysis are presented in Table V-12.

**Table V-12 PM<sub>10</sub>, PM<sub>2.5</sub>, and NO<sub>2</sub> Class I Significant Impact Analysis Results**

Pollutant	Avg. Period	Model Conc. (µg/m <sup>3</sup> )	Secondary Impact Conc. (µg/m <sup>3</sup> )	Total Conc. (µg/m <sup>3</sup> )	SIL (µg/m <sup>3</sup> )
PM <sub>10</sub>	24-hour	0.1 <sup>(1)</sup>	-	0.1	0.3
	Annual	0.004 <sup>(2)</sup>	-	0.004	0.2
PM <sub>2.5</sub>	24-hour	0.055 <sup>(3)</sup>	0.035	0.09	0.27
	Annual	0.0037 <sup>(4)</sup>	0.007	0.004	0.05
NO <sub>2</sub>	Annual	0.008 <sup>(2)</sup>	-	0.008	0.1

<sup>(1)</sup>Modeled concentration is the maximum 24-hour concentration in the 5-year period.

<sup>(2)</sup>Modeled concentration is the maximum annual concentration in the 5-year period.

<sup>(3)</sup>Modeled concentration is the maximum 5-year average 24-hour concentration.

<sup>(4)</sup>Modeled concentration is the maximum 5-year average annual concentration.

PSD Class I Area Impact Analysis

In accordance with the provisions of ARM 17.8.825 and ARM 17.8.1106 (visibility only), Phillips 66 evaluated the potential for the “Billings Projects for 2022” to impact the air quality related values (AQRVs) of nearby Class I areas.

A “Q/d” screening analysis was performed by summing together the net emissions increases of NO<sub>x</sub>, PM<sub>10</sub>, SO<sub>2</sub>, and H<sub>2</sub>SO<sub>4</sub> (Q) and dividing that by the distance to the Class I area (d). The results are shown in Table V-13. Because each Q/d result is considerably less than 10, the “Billings Projects for 2022” is not expected to negatively impact the AQRVs of the areas.

**Table V-13 Class I “Q/d” results**

Class I Area	Q (tpy)	d (km)	“Q/d”
North Absaroka Wilderness Area	153.81	138	1.11
Yellowstone National Park	153.81	145	1.06
Northern Cheyenne Reservation	153.81	147	1.05
Washakie Wilderness Area	153.81	171	0.90
UL Bend Wilderness Area	153.81	193	0.80

Teton Wilderness Area	153.81	200	0.77
Grand Teton National Park	153.81	259	0.59
Fitzpatrick Wilderness Area	153.81	271	0.57
Gates of the Mountains Wilderness Area	153.81	276	0.56
Red Rock Lakes Wilderness Area	153.81	277	0.56
Bridger Wilderness Area	153.81	285	0.54

In addition, Phillips 66 performed the analysis presented in ARM 17.8.1110(5) and determined the federal Class I areas visibility monitoring requirements of ARM 17.8.1110 be waived for the “Billings Projects for 2022”, because “V” is less than 0.5. The results of this analysis are in Table V-14.

**Table V-14 Federal Class I Area ARM 17.8.1110(5) Results**

<b>Class I Area</b>	<b>NO<sub>x</sub> Emissions (tpy)</b>	<b>d (km)</b>	<b>“V”</b>
North Absaroka Wilderness Area	82.87	138	0.07
Yellowstone National Park	82.87	145	0.06
Washakie Wilderness Area	82.87	171	0.05
UL Bend Wilderness Area	82.87	193	0.05
Teton Wilderness Area	82.87	200	0.05
Grand Teton National Park	82.87	259	0.04
Fitzpatrick Wilderness Area	82.87	271	0.03
Gates of the Mountains Wilderness Area	82.87	276	0.03
Red Rock Lakes Wilderness Area	82.87	277	0.03
Bridger Wilderness Area	82.87	285	0.03

Additional Impact Analysis

No associated permanent industrial growth was noted to occur due to the “Billings Projects for 2022” project due to i) the site is an established facility that has consistently operated for decades and ii) the project did not increase the site’s crude processing capacity. The project

did not require any municipal infrastructure construction activities that would have impacted the Billings area air quality.

Level I and Level II Visibility Analyses were performed by Phillips 66 using VISCREEN, and the results show that the “Billings Projects for 2022” would not impair local visibility. Phillips 66 provided a soils and vegetation analysis that demonstrates that emissions increases are not expected to have a harmful impact on soils and vegetation in the area of the site.

The Department determined that the project-related PM<sub>10</sub>, PM<sub>2.5</sub>, and NO<sub>2</sub> increases (with offsite facility PM<sub>2.5</sub> and NO<sub>2</sub> source emissions, and secondary PM<sub>2.5</sub> impacts) will not cause or contribute to a federal or state ambient air quality standard, will not exceed a PSD Class I or II increment, will protect Class I AQRVs including visibility, and will not impair the surrounding environment such as community/industrial growth, soils, crops, and vegetation. This decision was based on the air dispersion modeling with qualitative/quantitative analyses. The full modeling analysis submitted with the MAQP application is on file with the Department.

#### VI. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

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

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

VII. Environmental Assessment

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

**DEPARTMENT OF ENVIRONMENTAL QUALITY**  
**Air, Energy & Mining Division**  
**Air Quality Bureau**  
**1520 East Sixth Avenue**  
**P.O. Box 200901, Helena, Montana 59620-0901**  
**(406) 444-3490**

**ENVIRONMENTAL ASSESSMENT (EA)**

*Issued For:* Phillips 66 Company  
PO Box 30198  
Billings, MT 59107-0198

*Montana Air Quality Permit (MAQP) Number:* 2619-39

*EA Draft:* November 9, 2020

*EA Final:* December 21, 2020

*Permit Final:* January 6, 2021

1. *Legal Description of Site:* 401 South 23<sup>rd</sup> Street, Billings, Montana, in the NW<sup>1</sup>/<sub>4</sub> of Section 2, Township 1 South, Range 26 East, in Yellowstone County, Montana.
2. *Description of Project:* The purpose of the project is to authorize 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.
3. *Objectives of Project:* Adjust refinery operations and design to accommodate a wider range of crude oil slates.
4. *Alternatives Considered:* In addition to the proposed action, the Department also considered the “no-action” alternative. The “no-action” alternative would deny issuance of the MAQP to the proposed facility. However, the Department does not consider the “no-action” alternative to be appropriate because Phillips 66 demonstrated compliance with all applicable rules and regulations as required for permit issuance. Therefore, the “no-action” alternative was eliminated from further consideration.
5. *A listing of mitigation, stipulations and other controls:* A list of enforceable permit conditions and a complete permit analysis, including Best Achievable Control Technology determinations, would be contained in MAQP #2619-39.
6. *Regulatory effects on private property:* The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined that the permit conditions are reasonably necessary to ensure compliance with applicable requirements and to demonstrate compliance with those requirements and do not unduly

restrict private property rights.

SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS:  
The following comments have been prepared by the Department in reviewing potential effects within the borders of the State of Montana.

A. *Terrestrial and Aquatic Life and Habitats*

This permit action would allow for increases in allowable emissions from an existing source of these emissions. As required by the clean air act in order to receive the required permit, all emissions increases were demonstrated to not exceed ambient air quality standards and ambient increments, and not pose significant impacts to soils and vegetation. The project would occur within the footprint of the existing refinery. Wastewater related permitting would be required as described in the next section. Therefore, no significant impacts to terrestrial and aquatic life and habitats would be expected. The overall area, in general, has experienced significant decreases in emissions with time.

B. *Water Quality, Quantity, and Distribution*

Montana Pollutant Discharge Elimination System (MPDES) Permit No. MT0000256 and the site's City of Billings Significant Industrial User Permit would be required to be modified as necessary. Such programs are designed to protect water quality. Significant increases in water demand is not expected.

C. *Geology and Soil Quality, Stability, and Moisture*

This permitting action would not be expected to change the soil stability or geologic substructure or result in any increased disruption, displacement, erosion, compaction, or moisture loss, which would reduce productivity or fertility outside the boundaries of the facility. No unique geologic or physical features would be physically disturbed. Therefore, no significant impacts to geology and soil quality, stability, and moisture would be expected.

D. *Vegetation Cover, Quantity, and Quality*

The project would physically occur within the footprint of the already existing refinery. Emissions are not expected to significantly impact vegetation cover, quantity, or quality.

E. *Aesthetics*

The project would occur within the boundaries of an already existing and operating refinery, within a relatively industrial area. The surrounding area includes a stockyard (livestock), a sugar beet processing plant, warehouses, plumbing and HVAC shops, auto repair shops, and a petroleum bulk plant. Temporary construction activities would be expected, with resulting impacts short lived. No significant increases in noise levels would be expected as a result of the operations after construction/installation.

F. *Air Quality*

Impacts from allowable emissions are demonstrated to be less than applicable ambient air increment and less than the ambient air quality standards. The project would be required to apply Best Available Control Technology to all new or physically modified units. The application demonstrates acceptable impacts with respect to the requirements of the Administrative Rules of Montana 17.8 subchapter 8.

G. *Unique Endangered, Fragile, or Limited Environmental Resources*

The project would occur within the footprint of the existing refinery. As previously described, impacts to water quality, air quality, soils, and vegetation as a result of the emissions permitted in MAQP #2619-38 would not be expected to be significant. As such, no significant impact to endangered, fragile, or limited environmental resources would be expected.

H. *Demands on Environmental Resource of Water, Air, and Energy*

As discussed in Section B and Section F, impacts to water and air would not be expected to be significant. An increase in energy demand would be expected as a result of the installation of a new Hydrogen plant. The demand is not expected to have significant impacts on such resources.

I. *Historical and Archaeological Sites*

The project would occur within the boundaries of the existing refinery. Impacts to any historical and archaeological sites would be expected to be minor, if any at all. The Department would not consider impacts to the refinery itself as significant.

J. *Cumulative and Secondary Impacts*

Impacts to the individual physical and biological considerations above are considered to be minor. Cumulatively, these impacts are expected to be minor. Further, secondary impacts would be expected to be minor. The issuance of MAQP #2619-39 would be based on an application demonstrating compliance with all applicable clean air act requirements.

SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS: The following comments have been prepared by the Department:

A. *Social Structures and Mores*

The permitting action would not be expected to cause a disruption to any native or traditional lifestyles or communities (social structures or mores) in the area because the nature of the site would not be changed, and additional employment is not expected. Any impacts to social structures and mores would be expected to be minor, if any at all.

B. *Cultural Uniqueness and Diversity*

The permitting action would not cause a change in the cultural uniqueness and diversity of the area because the land is currently used as a petroleum refinery; therefore, the land use would not be changing. The nature of the site would not be changed, and additional employment is not expected. Any impacts to cultural uniqueness and diversity would be expected to be minor, if any at all.

C. *Local and State Tax Base and Tax Revenue*

No new employees would be needed for this project. No significant impacts to the local and state tax base and tax revenue would be expected.

D. *Agricultural or Industrial Production*

The permitting action would not result in a reduction of available acreage or productivity of any agricultural land. No significant impacts to land would be expected. Any impacts to agricultural production would be expected to be minor, if any discernable amount at all. Any impacts to industrial production would be expected to be minor, if any at all. No increase in the overall crude refining rate is expected, and no more than minor impacts to soils and vegetation expected.

E. *Human Health*

As described in Section 7.F and 7.H of this environmental assessment, impacts on air quality, water quality, and energy demands are expected to be within those allowable by rule. No more than minor impacts to human health would be expected as a result of this permitting action.

F. *Access to and Quality of Recreational and Wilderness Activities*

This permitting action would not be expected to have an impact on recreational or wilderness activities because the site is far removed from recreational and wilderness areas or access routes. The action would not result in any changes in access to and quality of recreational and wilderness activities, and would not result in the need for construction outside the boundaries of the existing refinery. Any impacts to recreational and wilderness activities would be expected to be minor.

G. *Quantity and Distribution of Employment*

No change in the number of employees currently onsite would be anticipated as a result of this permitting action. Therefore, any impacts to the quantity and distribution of employment at the facility would be expected to be minor, if any at all.

H. *Distribution of Population*

This permitting action does not involve any physical change that would affect the location, distribution, density, or growth rate of the human population. The distribution of population would not be expected to change as a result of this action. No new employment at the refinery is expected. Any impacts would be expected to

be minor, if any at all.

I. *Demands of Government Services*

The demands on government services would experience a minor impact. The primary demand on government services would be the acquisition of the appropriate permits by the facility and compliance verification with those permits.

J. *Industrial and Commercial Activity*

No significant impacts to industrial and commercial activity would be expected. Temporary construction activities would be expected. No increase in overall crude refining rate is expected as a result of the project. An increase in sulfur product production at the Jupiter Sulphur plant is expected. .

K. *Locally Adopted Environmental Plans and Goals*

The Department is not aware of any locally adopted environmental plans or goals that the issuance of MAQP 2619-39 would effect.

L. *Cumulative and Secondary Impacts*

No significant impacts to the individual social and economic considerations above would be expected. From a cumulative viewpoint, and in consideration of secondary impacts, impacts would be expected to be minor. The issuance of MAQP #2619-39 would be based on an application demonstrating compliance with all applicable clean air act requirements.

Recommendation: An Environmental Impact Statement (EIS) is not required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: No significant effects resulting from this permitting action would be expected; therefore, an EIS is not required. In addition, the source would be applying BACT and the analysis indicates compliance with all applicable air quality rules and regulations.

Other groups or agencies contacted or which may have overlapping jurisdiction: None.

Individuals or groups contributing to this EA: Department of Environmental Quality - Air Quality Bureau

EA Prepared By: Shawn Juers

Date: October 20, 2020