Montana Department of Environmental Quality

Air, Energy & Mining Division

March 28, 2025

Jeff Dusch, VP, Refinery Manager
Par Montana, LLC.
Billing Refinery
700 Montana Par Road
Billings, MT 59701

Sent via email: jdusch@parpacific.com

RE: Final Permit Issuance for MAQP #1564-38

Dear Mr. Dusch:

Montana Air Quality Permit (MAQP) #1564-38 is deemed final as of March 22, 2025, by DEQ. This permit is for Par Montana, LLC. – Billings Refinery. All conditions of the Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

For DEQ,

Eric Merchant
Permitting Services Section Supervisor
Air Quality Bureau
(406) 444-0286

for Paul Proulx

John P. Proulx
Air Quality Engineer
Air Quality Bureau
(406) 444-5391

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

Montana Air Quality Permit #1564-38

Par Montana, LLC.
Billing Refinery
700 Montana Par Road
Billings, MT 59701

March 22, 2025

MONTANA AIR QUALITY PERMIT

Issued to:	Par Montana, LLC. Billings Refinery P.O. Box 1163 Billings, MT 59106	MAQP: #1546-38 Application Complete: 12/20/2024 Preliminary Determination Issued: 01/29/2025 Department Decision Issued: 03/06/2025 Permit Final: 03/22/2025

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

Section I: Permitted Facilities

A. Plant Location

The Par Montana, LLC. – Billings Refinery is located at 700 Montana Par Road in Billings, Montana. The Yellowstone River forms the northern and northeastern boundaries, and Interstate 90 lies along the southern border. Refinery units and storage tanks lie in the southern half of Section 24 and the northern half of Section 25, Township 1 North, Range 26 East, in Yellowstone County, Montana. The active refinery occupies approximately 380 acres on a level plot.

B. Permitted Facility

This permit covers all existing sources of air contaminants at the above-described petroleum facility. A list of permitted equipment can be found in the permit analysis section of this permit. The refinery also includes the bulk marketing distribution terminal, which stores and transfers petroleum products (gasoline and distillate) received from the refinery and distributes them to regional markets via tank truck. The terminal is located adjacent to and south of the refinery and operates under MAQP #2967; however, because Par is a major source of emissions pursuant to ARM, Title 17, Chapter 8, Subchapter(s) 8, 9, and 10 the terminal and refinery are considered one facility for the purposes of permitting evaluations.

C. Current Permit Action

On December 20, 2024, the Montana Department of Environmental Quality – Air Quality Bureau (DEQ) received an application for permit modification from Par Montana, LLC, to address proposed changes to the Crude Furnace (F-1) to improve efficiency primarily through updating tube design within the furnace building. The improved design would provide for reduced tube fouling and provide the means for mechanical cleaning thereby resulting in less downtime associated with maintenance.

Section II. Limitations and Conditions

A. General Facility Conditions

1. Par shall, any time the Yellowstone Energy Limited Partnership (YELP) facility is operating, send all of its coker process gas to either one or both of YELP's boilers. During startup and shutdown conditions at YELP, Par shall supply the maximum amount of coker process gas that YELP can accept.

2. A refinery-wide block hourly limit of 0.96 pounds (lb) of sulfur in fuel per million British thermal units (MMBtu) fired shall be adhered to at all times. In the event Par fails to meet the hourly limit of 0.96 lb of sulfur per MMBtu fired, Par shall immediately notify YELP of this occurrence. After such an occurrence, Par shall also provide subsequent notification to YELP when it has met the hourly sulfur-in-fuel limitation for three-consecutive hourly periods.

3. Any time Par diverts process coker gases from YELP, Par shall report said diversion to DEQ within 24 hours or during the next working day. This information shall also be included in the quarterly continuous emission monitors (CEMS) sulfur-in-fuel report and include period(s) of diversion, quantity of sulfur oxide emissions, reason(s) for diversion(s), and corrective measures taken to prevent recurrence.

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

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

6. Par shall comply with all the applicable standards and limitations, and the monitoring, recordkeeping, and reporting requirements contained in 40 CFR 60, Subpart A and Subpart J – Standards of Performance for Petroleum Refineries (ARM 17.8.340 and 40 CFR 60 Subpart J).

7. The requirements of 40 CFR 60, Subpart J shall apply to the refinery as follows (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart J, unless otherwise noted):

    a. The FCC Unit catalyst regenerator is an affected facility under 40 CFR 60, Subpart J and shall comply with the emission limitations of 40 CFR 60, Subpart J for Particulate Matter (PM), carbon monoxide (CO), and opacity (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart J).

Par shall ensure the each FCCU catalyst regenerator complies with the applicable emissions limitations imposed by NSPS J except during periods of startup, shutdown, or Malfunction as defined by 40 CFR 60.2. At all times, including startup, shutdown, and Malfunctions, Par shall, to the extent practicable, maintain and operate each FCCU catalyst regenerator and any associated air pollution control equipment in a manner consistent with good air pollution control practice and minimize emissions. (ARM 17.8.749);

b. Par shall meet 40 CFR 60, Subpart J requirements for the Sour Water Stripping Unit (SWS) T-23 Overhead Gas by rerouting or treating SWS feed with hydrogen peroxide;

c. All heaters and boilers listed in the table below (*with the exception of B-8*) are affected facilities under 40 CFR 60, Subpart J for Fuel Gas Combustion Devices and shall comply with all applicable requirements of 40 CFR 60, Subpart J – Standards of Performance for Petroleum refineries, as it applies to fuel gas combustion devices.

Emitting Unit	Name
EU01a	F-2 (F-1 & F-401)
EU01b	F-3 Heater
EU02a	F-3x Heater
EU02b	F-5 Heater
EU03a	KCOB
EU03b	F-202 Heater
EU04a	F-700 Heater
EU05a	F-402 Heater
EU07a	F-201 Heater
EU09a	CCOB
EU11a	F-651 Heater
EU12a	F-551 Heater
EU13	B-8 Boiler (B-8)
EU14b	F-10 Heater
EU16a	F-1201 Heater

Par shall not burn in any fuel gas combustion device any fuel gas that contains hydrogen sulfide (H_2S) in excess of 230 milligrams per dry standard cubic meter (mg/dscm) (0.10 grains per dry standard cubic foot (gr/dscf) or 162 parts per million volume dry basis (ppmvd)) per rolling 3-hour period (ARM 17.8.749, A RM 17.8.340, and 40 CFR 60 Subpart J);

d. The main and turnaround flares shall meet the requirements of 40 CFR 60, Subparts A and Ja for flares;

e. Par shall install and operate a continuous monitor pursuant to 40 CFR 60.105(a)(4) or with a parametric monitoring system approved by EPA as an alternative monitoring system under 40 CFR 60.13(i).
CEMS shall be installed, calibrated, and certified in accordance with 40 CFR 60.13 and 40 CFR 60, Appendices A and F, and the applicable performance specification test of 40 CFR 60, Appendix B (ARM 17.8.340, ARM 17.8.749, and 40 CFR 60, Subpart Ja).

8. Par shall comply with all applicable requirements of 40 CFR 60, Subpart Ja, including as applicable to the main and turnaround flares, and Boiler B-8 if connection to refinery fuel gas is made for this boiler (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

9. Par shall comply with all the applicable requirements of 40 CFR 60, Subpart GGG – Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced after January 4, 1983, and on or before November 7, 2006, as it applies to this refinery (ARM 17.8.340 and 40 CFR 60, Subpart GGG).

10. Par shall comply with all applicable requirements of 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, as it applies to this refinery (ARM 17.8.340 and 40 CFR 60, Subpart GGGa).

11. Par shall comply with all applicable requirements of 40 CFR 63, Subpart CC – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as it applies to this refinery. This requirement includes the vapor control equipment installed on Tank #309 (ARM 17.8.342 and 40 CFR 63, Subpart CC).

12. Par shall comply with all applicable requirements of 40 CFR 63, Subpart UUU – National Emission Standards for Hazardous Air Pollutants from Petroleum Refineries, as it applies to this refinery (ARM 17.8.342 and 40 CFR 63, Subpart UUU).

13. Par shall comply with all applicable requirements of 40 CFR 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (ARM 17.8.342 and 40 CFR 63, Subpart DDDDD).

14. Par shall comply with all applicable requirements of 40 CFR 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (ARM 17.8.340 and 40 CFR 60, Subpart Kb).

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

16. Par shall comply with all applicable requirements of 40 CFR 63, Subpart ZZZZ – National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (ARM 17.8.342 and 40 CFR 63, Subpart ZZZZ).

17. Par shall comply with all applicable requirements of 40 CFR 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (ARM 17.8.340 and 40 CFR 60, Subpart IIII).

18. Par shall comply with all applicable requirements of 40 CFR 60, Subpart Dc – Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units, including as applicable to the B-8 boiler (ARM 17.8.340 and 40 CFR 60, Subpart Dc).

B. Polymer Modified Asphalt (PMA) Unit

1. Par shall maintain the operating temperature of the wetting/mixing tank below the smoking point of asphalt. Par shall not cause or authorize emissions to be discharged into the outdoor atmosphere, from the wetting/mixing tank, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304 and 17.8.752).

2. All valves used shall be high quality valves containing high quality packing (ARM 17.8.752).

3. All open-ended valves shall be of the same quality as the valves described above, and they shall have plugs or caps installed on the open end (ARM 17.8.752).

4. All pumps and mills used in the PMA unit shall be equipped with standard high-quality single seals (ARM 17.8.752).

5. Flanges shall be equipped with process-compatible gasket material (ARM 17.8.749).

6. All applicable requirements of ARM 17.8.340, which reference 40 CFR Part 60, Standards of Performance for New Stationary Sources and Subpart GGG – Equipment Leaks of VOC in Petroleum Refineries, shall apply to the PMA process unit and any other equipment, as appropriate. A monitoring and maintenance program, as described under New Source Performance Standards (40 CFR Part 60, Subpart VV), shall be instituted (ARM 17.8.340 and 40 CFR 60, Subpart GGG).

7. The PMA unit may process either non-polymerized or polymer modified asphalt (ARM 17.8.749).

8. Once the PMA unit is modified, the PMA tanks (Tanks #72, #73, #76, & #77) combined shall not exceed 28.3 tons of VOC emissions per 12-month rolling period (ARM 17.8.749).

9. Once the PMA unit is modified, the PMA loading operations shall not exceed 22.7 tons of VOC emissions per 12-month rolling period (ARM 17.8.749).

10. Once the PMA unit is modified, the PMA Tanks and the PMA loading operations shall be limited to a combined total of 46.6 tons of VOC emissions per 12-month rolling period (ARM 17.8.749).

C. D-4 Drum Atmospheric Vent Stack

1. Par shall not cause or authorize emissions to be discharged into the outdoor atmosphere from the D-4 drum atmospheric vent stack that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

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

D. FCC Unit and CO Boiler Stack

1. Par shall not cause or authorize emissions to be discharged into the outdoor atmosphere, from the FCC CO Boiler stack, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes, except as allowed under the rule (ARM 17.8.304).

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

3. Par shall install and operate a third-stage cyclone on the FCC Unit, and take any additional steps necessary, in order to comply with a PM emission limit of 1.0 lb of PM per 1,000 lb of coke burned (ARM 17.8.749; ARM 17.8.340 and 40 CFR 60, Subpart J).

PM emissions (i) caused by or attributed to the startup and shutdown of the FCCU and/or (ii) during periods of Malfunction of the FCCU or Malfunction of third-stage cyclone will not be used in determining compliance with the PM emission limit provided that during such periods Par implements good air pollution control practices to minimize PM emissions (ARM 17.8.749).

4. Par shall comply with 500 parts per million, volumetric dry (ppmvd) CO corrected to 0% oxygen (O_2) on a 1-hour average basis on the FCC Unit (ARM 17.8.749, ARM 17.8.340 and 40 CFR 60, Subpart J).

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

5. Par shall comply with the following SO_2 emission limits on the FCCU (ARM 17.8.749):

   a. 177.3 ppm_{vd} at 0% O_2 on a 365-day rolling average basis, applicable at all times (including during startup, shutdown, and malfunction) that the FCCU is operating. For days in which the FCCU is not operating, no SO_2 values shall be used in the averages, and those periods shall be skipped in determining the 365-day averages (ARM 17.8.749); and

   b. 300.0 ppm_{vd} at 0% O_2 on a 7-day rolling average basis. SO_2 emissions (i) caused by or attributed to the startup, shutdown, or malfunction of the FCCU and/or (ii) during periods of malfunction of the SO_2 reducing catalyst additive system will not be used in determining compliance with the short-term (7-day) SO_2 emission limit provided that during such periods Par implements good air pollution control practices to minimize SO_2 emissions (ARM 17.8.749).

6. Par shall comply with the following nitrogen oxides (NO_X) emission limits on the FCC Unit (ARM 17.8.749):

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

   b. 80 ppmvd at 0% O_2 on a 7-day rolling average basis, other than FCC Unit NO_x emissions during a period of natural gas curtailment when fuel oil is burned. During such period of natural gas curtailment, Par shall comply with an alternate short-term NO_x limit of 120 ppmvd at 0% O_2 on a 24-hour rolling average basis.

NO_X emissions (i) caused by or attributed to the startup, shutdown, or malfunction of the FCC Unit and/or (ii) during periods of malfunction of the selective catalytic reduction unit (SCR) will not be used in determining compliance with the short-term (7-day) NOx emission limit provided that during such periods Par implements good air pollution control practices to minimize NO_X emissions (ARM 17.8.749).

E. F-2 Crude/Vacuum Heater Stack

Par shall not cause or authorize emissions to be discharged into the outdoor atmosphere from the F-2 Crude/Vacuum Heater stack that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes, except as allowed under the rule (ARM 17.8.304).

F. Furnace F-1201

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

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

3. Par shall not cause or authorize to be discharged into the atmosphere from furnace F-1201, any visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

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

G. Process Heater F-201 and Process Heater F-5

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

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

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

H. Furnace F-551

1. The NO_x emissions from F-551 shall not exceed 23.35 lb/hr (ARM 17.8.749).

2. Par shall not cause or authorize to be discharged into the atmosphere from F-551, any visible emissions that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

3. The NO_X emissions from F-551 shall not exceed 75.55 tons per rolling 12-month period (ARM 17.8.752).

I. RFG Combustion Sources

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

   a. Combined 3-hour emissions of SO_2 from the RFG combustion units shall not exceed 92.4 lb per 3-hour period, and
   b. Combined daily emissions of SO_2 from the RFG combustion units shall not exceed 739.2 lb per calendar day.

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

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

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

J. Tanks

1. Par shall maintain onsite and available upon request, a site diagram identifying each tank. (ARM 17.8.749).

2. Par shall maintain onsite and available upon request, records of Tank service and annualized throughput (ARM 17.8.749).

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

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

   Where:

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

4. Par shall comply with all applicable tank requirements of 40 CFR 63 Subpart CC (ARM 17.8.342, ARM 17.8.302, and 40 CFR 63 Subpart CC).

5. Par shall comply with all applicable requirements of 40 CFR 60 Subpart Kb (ARM 17.8.340, ARM 17.8.302, and 40 CFR 60 Subpart Kb).

K. Emergency Portable and Stationary Engines

1. The emergency engines are limited to the hours of operation on a rolling 12-month time period, maximum horsepower rating, and minimum Tier Rating listed below:

ID No.	Emitting Unit ID	Description	Limited Hours	Rule Reference
SE1	HC/M601	Hydrocracker Backup Power Generator –Diesel	1,800 hr/yr	ARM 17.8.752
SE2	UT/P917B	Cooling Water Return to Alkylation Unit Water Screen (Fire Water) – Diesel	1,000 hr/yr	ARM 17.8.752
SE3	UT/P917A	Cooling Water Return to Alkylation Unit Water Screen (Fire Water) – Diesel	1,000 hr/yr	ARM 17.8.752
SE4	UT/P916	Pond 6 Water to Fire Mains – Diesel	1,000 hr/yr	ARM 17.8.752
SE5	CR/M201	Crude/Coker Backup Power Generator - Diesel	2,000 hr/yr	ARM 17.8.752
SE6	UT/C4	Boiler House Air Compressor – Diesel, minimum EPA Tier II rating, not to exceed 475-hp	2,000 hr/yr	ARM 17.8.749
SE7	UT/Port1	Boiler House Backup Air Compressor, Portable, Diesel-fired, not to exceed 600-hp	1,500 hr/yr	ARM 17.8.749
SE8	UT/Port2	Boiler House Backup Air Compressor, Portable, Diesel-fired, not to exceed 600-hp	1,500 hr/yr	ARM 17.8.749
SE9	EMES/Eng01	Site Remediation, Diesel-fired, not to exceed 250-hp	No limit on hours	ARM 17.8.749
SE10	EMES/Eng02	Site Remediation, Diesel-fired, not to exceed 250-hp	No limit on hours	ARM 17.8.749
SE11	EMES/Eng03	Site Remediation, Diesel-fired, not to exceed 250-hp	No limit on hours	ARM 17.8.749
SE12*	EMES/Eng04	Miscellaneous use, Diesel-fired, not to exceed 500-hp each	2,100,000 hp-hrs**	ARM 17.8.749
SE13	EMES/Eng05	Emergency and Site Remediation, Diesel-fired, not to exceed 100-hp	No limit on hours	ARM 17.8.749
SE14	UT/Port3	SLEB Backup Portable Engine, diesel fired, not to exceed 600 hp, minimum EPA Tier III rating	3,000 hr/yr	ARM 17.8.749
IEU06a	UT/P1A	Fire Water Pump at River Water Pump House -Gasoline	2,000 hr/yr	ARM 17.8.752
IEU06b	UT/P1B	Fire Water Pump at River Water Pump House -Gasoline	2,000 hr/yr	ARM 17.8.752

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

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

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

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

4. Par shall use only low-sulfur diesel fuel with a sulfur content less than or equal to 0.05% in SE1 through SE6 (ARM 17.8.752).

5. Par shall use only ultra-low sulfur diesel fuel with a sulfur content less than or equal to 0.0015% in SE7 through SE14 (ARM 17.8.752).

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

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

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

9. Par shall comply with all applicable requirements of 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (ARM 17.8.340 and 40 CFR 60 Subpart IIII).

L. Boiler B-8 (Standby Boiler House)

1. Par shall provide written notification to DEQ as follows (ARM 17.8.749):

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

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

2. If Boiler B-8 is modified to combust refinery fuel gas, Par shall not burn fuel gas that contains H_2S in excess of 162 ppmvd determined hourly on a 3-hour rolling average basis and H_2S in excess of 60 ppmvd determined daily on a 365-successive calendar day rolling average basis, as measured in accord with

40 CFR 60 Subpart Ja (ARM 17.8.752, ARM 17.8.340, and 40 CFR 60 Subpart Ja).

3. SO_2 emissions from B-8 shall not exceed:

   a. 3.40 tons per rolling 12-month period (ARM 17.8.749)

   b. 0.78 lb/hr (ARM 17.8.749)

4. The NO_X emissions from B-8 shall not exceed:

   a. 0.04 lb/MMBtu based on a one-hour average and corrected to 3% excess O_2, on a dry basis, not applicable during start-up[1] and shutdown[1]. At all times, including periods of startup, shutdown, and malfunction, Par shall, to the extent practicable, maintain and operate Boiler B-8 in a manner consistent with good air pollution control practice for minimizing emissions. (ARM 17.8.749 and ARM 17.8.752)

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

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

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

   a. 0.04 lb/MMBtu based on a one-hour average and corrected to 3% excess O_2, on a dry basis, not applicable during start-up[1] and shutdown[1]. At all times, including periods of startup, shutdown, and malfunction, Par shall, to the extent practicable, maintain and operate Boiler B-8 in a manner consistent with good air pollution control practice for minimizing emissions. (ARM 17.8.749 and ARM 17.8.752)

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

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

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

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

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

[1] Start-up for B-8 is defined as the duration of time from the initial start of the unit to the point in time at which the firing rate exceeds 25% of the unit's maximum capacity rating. Shutdown for B-8 is defined as the duration of time from the point at which the firing rate drops below 25% of the unit's maximum capacity rating to the point in time that fuel is no longer being combusted within the unit. For purposes of PTE calculations on an annual basis, use of 0.04 lb/MMBtu is appropriate.

M. FCCU Wet Gas Compressor (C-310)

All applicable requirements 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, shall apply to the C-310 compressor and any other equipment, as appropriate.
A monitoring and maintenance program, as described under 40 CFR Part 60, Subpart VVa, shall be instituted (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart GGGa).

N. Crude Furnace (F-1)

1. NO_X emissions from the crude furnace (F-1) shall not exceed 58.0 pounds per hour. This limit does not include when sour water stripper overhead is being routed to F-1 (ARM 17.8.752).

2. CO emissions from F-1 shall not exceed 23.7 pounds per hour. This limit does not include when sour water stripper overhead is being routed to F-1 (ARM 17.8.752).

3. Par shall use good combustion practices for NO_X and CO minimization (ARM 17.8.752).

4. Par shall burn only natural gas for the pilot light and refinery fuel gas for the main burners in F-1 (ARM 17.8.749, 17.8.752).

O. Monitoring

1. Par shall install and operate the following CEMS/Continuous Opacity Monitoring System (COMS)/Continuous Emission Rate Monitor System (CERMS) at the FCC Unit CO Boiler Stack. CEMS shall be installed, certified, calibrated, maintained, and operated in accordance with 40 CFR 60.13 and 40 CFR 60, Appendices A and F, and the applicable performance specification test of 40 CFR 60, Appendix B.

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

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

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

   d. NO_X (ARM 17.8.749);

   e. O_2 (ARM 17.8.749, ARM 17.8.340, and 40 CFR 60 Subpart J); and

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

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

3. Compliance and enforcement of the requirements on SO2 emission rates andH2S concentrations in Sections II.I.1 and II.I.2 shall be determined by utilizing data taken from CEMS and other DEQ-approved sampling methods (ARM 17.8.749, Billings/Laurel SO2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

4. In the event the primary SO2 or H2S CEMS are unable to meet minimum availability requirements, Par shall provide a back-up or alternative monitoring system and plan such that continuous compliance can be demonstrated. DEQ shall approve such contingency plans.

   SO_2 and H_2S CEMS shall be required to be maintained such that they are available and operating at least 90% of the source operating time during any reporting period (quarterly) (ARM 17.8.749 and Billings/Laurel SO_2 Control Plan, approved into the SIP by EPA on May 2, 2002, and May 22, 2003).

5. All gaseous CEMS shall be required to comply with quality assurance/quality control procedures in 40 CFR 60, Appendix F (ARM 17.8.749).

6. Par shall install, operate and maintain the applicable CEMS or develop an AMP as required by 40 CFR 60, Subparts A and J. Emission monitoring shall comply with all applicable provisions of 40 CFR 60.7 through 60.13; 40 CFR 60, Appendix A; Appendix B (Performance Specifications 1, 2, 3, 4, 6 and 7); and Appendix F (Quality Assurance/Quality Control) provisions (ARM 17.8.749).

7. Emissions (i) caused by or attributable to the startup, shutdown, or malfunction of an FCC Unit and/or (ii) during periods of malfunction of the relevant FCC Unit's Control System(s) will not be used in determining compliance with the PM limit or short-term (7-day for NOx, 7-day for SO2, or 1-hour for CO) limits, provided that during such periods Par implements good air pollution control practices to minimize said emissions. NOx, SO2, and CO emissions during any such period of startup, shutdown, or malfunction shall either be: (i) monitored with CEMS; or (ii) monitored in accordance with an alternative monitoring plan approved by the Environmental Protection Agency (EPA) if it is necessary to bypass the FCC Unit's main stack during the particular period of startup, shutdown, or malfunction (ARM 17.8.749).

8. Par shall comply with the applicable monitoring requirements contained in 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

9. Par shall continuously monitor the heat input rate into B-8 and provide averages on a rolling 24-hour basis. This information shall be used to verify compliance with the rolling 24-hour average limitation in Section II.L.7 (ARM 17.8.749).

P. Testing Requirements

1. Par shall test furnace F-1201 on an every 5-year basis after the initial source test, or according to another testing/monitoring schedule as may be approved by DEQ, to demonstrate compliance with the NO_x limitations for furnace F-1201 found in Section II.F.1 (ARM 17.8.106 and 17.8.749).

2. Par shall test furnace F-551 on an every 5-year basis after the initial source test, or according to another testing/monitoring schedule as may be approved by DEQ, to demonstrate compliance with the NO_x limitation for furnace F-551 found in Section II.H.1 (ARM 17.8.106 and 17.8.749).

3. Par shall perform a Method 5F test on the FCC Unit annually or according to another schedule as may be approved by the Administrator, to monitor compliance with the PM limitation found in Section II.D.3 (ARM 17.8.749, ARM 17.8.105, ARM 17.8.340 and 40 CFR 60, Subpart J).

4. Par shall test the PMA Process Unit for Equipment leaks in accordance with 40 CFR 60, Subpart GGG (ARM 17.8.340 and 40 CFR 60, Subpart GGG).

5. In addition to the opacity CEMS required for the FCC Unit stack, opacity compliance may also be determined via EPA Reference Method 9 by a certified observer.

6. Compliance testing and continuous monitor certification shall be as specified in 40 CFR 60, Appendices A and B. Test methods and procedures, where there is more than one option for any given pollutant, shall be worked out with DEQ prior to commencement of testing.

7. Par shall conduct compliance testing and continuous monitor certification as specified in 40 CFR 60, Appendices A and B, within 180 days of initial startup of the affected facility.

8. Any stack testing that may be required shall be conducted according to 40 CFR 60, Appendix A and ARM 17.8.105, Testing Requirements provisions.

9. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

10. Prior to any refinery fuel gas connection to Boiler B-8, this boiler shall be tested on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by DEQ, for NO_x and CO, concurrently, and the results submitted to DEQ. After connection of refinery fuel gas to Boiler B-8, this boiler shall be tested within 180 days for NO_X and CO

concurrently. Thereafter, Boiler B-8 shall be tested biennially for NO_X and CO concurrently. (ARM 17.8.749, ARM 17.8.105)

11. Par shall test the C-310 compressor for equipment leaks in accordance with 40 CFR 60, Subpart GGGa (ARM 17.8.340 and 40 CFR 60, Subpart GGGa).

12. Par shall test the Crude Furnace (F-1) for NO_X within 180 days of startup following the completion of the F-1 tube upgrades, and every 5 years thereafter. An alternative testing/monitoring schedule may be approved by DEQ to demonstrate compliance with NO_X limitations located in Section II.N.1(ARM 17.8.105 and ARM 17.8.749).

13. DEQ may require further testing (ARM 17.8.105).

Q. Operational Reporting Requirements

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

   Production information shall be gathered on a calendar-year basis and submitted to DEQ by the date required in the emission inventory request. Information shall be in the units required by DEQ.
   This information may be used for calculating operating fees, based on the actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. Par shall notify DEQ of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include the addition of a new emissions unit, 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.

   The notice must be submitted to DEQ, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

3. All records compiled in accordance with this permit must be maintained by Par as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by DEQ, and must be submitted to DEQ upon request (ARM 17.8.749).

4. Par shall document, by month, the total amount of RFG/natural gas consumed by furnace F-1201. By the 25th day of each month Par shall calculate the total amount of RFG/natural gas consumed by furnace F-1201

during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.F.4. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.P.1 (ARM 17.8.749).

5. Par shall document by month, the average monthly percent of maximum firing rate, the monthly gas consumption (MMscf per month), the input fuel heat content (MMBtu/MMscf), and the monthly hours of operation of F-201 and F-5 for use in the following equations:

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

Where:

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

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

NO_X lb/hr = {(Y) * (gas consumption (MMscf/month)) * (fuel heat content (MMBtu/MMscf))} / (hours of operation per month (hr/month))
NO_X tons per month = {NO_X (lb/hr) * (hr/month)} / 2000 lb/ton

6. Par shall document, by month, the amount of total NO_x emissions from F-201 and F-5. By the 25th day of each month Par shall calculate the total amount of NO_X emissions from F-201 and F-5 during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.G.3. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.P.1 (ARM 17.8.749).

7. Par shall document, by month, the amount of total SO_2, NO_X, and CO emissions from the B-8 boiler. By the 25th of each month, Par shall calculate and record the total amount of SO_2 emissions from the B-8 boiler during the previous month and calculate and record the rolling 12-month sum. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.P.1. (ARM 17.8.749).

8. Par shall document, by month, the total fugitive VOC emissions from Tank 26. By the 25th day of each month Par shall total the fugitive VOC emissions from Tank 26 during the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.J. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.P.1 (ARM 17.8.749).

9. Par shall document, by month, the total VOC emissions from the PMA tanks (#72, #73, #76 & #77). By the 25th day of each month Par shall calculate the total VOC emissions from these tanks during the previous month. Par shall measure actual tank data (throughput and temperature) and use this data to calculate VOC emissions using AP-42 calculation methods. The monthly information shall be used to verify compliance with the rolling 12-month limitations in Section II.B.8 and II.B.10. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.P.1 (ARM 17.8.749).

10. Par shall document, by month, the total VOC emissions from the PMA loading operation. By the 25th day of each month Par shall calculate the total VOC emissions from this operation during the previous month. Par shall measure the actual monthly PMA throughput and monthly average temperature, and use this data in the petroleum liquid loading equation:

    $L_L = 12.46$ SPM/T *(AP-42 Chapter 5.2)*
    L_L = loading loss (lbs/1000 gallons of PMA loaded)
    S = saturation factor (1.45)
    P = true vapor pressure
    M = molecular weight of vapors (105 lbs/lb-mole)
    T = temperature of bulk liquids loading (deg R)

    The monthly information shall be used to verify compliance with the rolling 12-month limitations in Section II.B.9 and II.B.10. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.P.1 (ARM 17.8.749).

11. Par shall sum the monthly VOC emissions from the PMA tanks and the PMA loading. The monthly information shall be used to verify compliance with the rolling 12-month limitation in Section II.B.10. The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.P.1 (ARM 17.8.749).

12. Par shall document by the 25^{th} day of each month the number of operational hours since the previous month's documentation event for each of the engines listed in Section II.K.1. The monthly information shall be used to verify compliance with the rolling 12-month limitations in Section II.K.1.

    The information for each of the previous months shall be submitted along with the annual emission inventory required by Section II.P.1 (ARM 17.8.749).

13. Par shall document, annually, the maximum sulfur content of the diesel and gasoline fuel used by the engines for the previous calendar year. Vendor specifications or certification that the fuels met the maximum sulfur content allowed by the current motor fuel regulations (40 CFR Part 80) will satisfy

this requirement. The annual information shall be used to verify compliance with the limitations in Section II.K.3, 4, and 5. The information shall be submitted along with the annual emission inventory required by Section II.P.1 (ARM 17.8.749 and ARM 17.8.752).

14. Par shall provide quarterly emission reports from said emission rate monitors. Emission reporting for SO_2 from all point source locations shall consist of 24-hour calendar-day totals per quarter. The quarterly report shall also include the following:

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

    b. Monitoring downtime that occurred during the reporting period.

    c. A summary of excess H_2S concentrations and/or SO_2 emissions and averaging period, for each new unit, as identified in Section II.I.

    d. Reasons for any emissions in excess of those specifically allowed in Section II.I, with mitigative measures utilized and corrective actions taken to prevent a recurrence of the upset situation.

    Par shall submit quarterly emission reports within 30 days of the end of each calendar quarter.

15. Par shall keep DEQ apprised of the status of construction of the new and modified units, dates of performance tests, and continuous compliance status for each emission point and pollutant. Specifically, the following report and recordkeeping shall be required in writing:

    a. Notification of initial emission tests and monitor certification tests.

    b. Submittal for review by DEQ of the emission testing plan, results of initial compliance tests, continuous emission monitor certification tests, continuous emission monitoring and continuous emission monitoring quality assurance/quality control plans, and excess emissions report format within the 180-day shakedown period.

    c. Copies of quarterly emission reports, H_2S and SO_2 monitoring data, excess emissions, and all other such items mentioned in Section II.Q.16.a and b, above, shall be submitted to both the Billings regional office and the Helena office of DEQ.

    d. Monitoring data shall be maintained for a minimum of 5 years at the Billings Par Refinery.

    e. All data and records that are required to be maintained must be made available, upon request, to representatives of DEQ and the U.S. Environmental Protection Agency.

16. Par shall comply with the recordkeeping and reporting requirements contained in 40 CFR 60, Subpart GGG (ARM 17.8.340 and 40 CFR 60, Subpart GGG).

17. Based on the monitoring required in Section II.O.10, Par shall document any exceedance of the rolling 24-hour average limitation specified in Section II.L.6. Any exceedance shall be reported and submitted with the quarterly emission report required in Section II.P.15 (ARM 17.8.749).

18. Par shall comply with the recordkeeping and reporting requirements contained in 40 CFR 60, Subpart GGGa (ARM 17.8.340 and 40 CFR 60, Subpart GGGa).

19. Par shall comply with the recordkeeping and reporting requirements contained in 40 CFR 60, Subpart Ja (ARM 17.8.340 and 40 CFR 60, Subpart Ja).

20. Reporting requirements shall be consistent with 40 CFR Part 60, or as specified by DEQ (ARM 17.8.340 and ARM 17.8.749).

Section III. General Conditions

A. Inspection – Par shall allow DEQ's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (continuous emissions monitoring system (CEMS) or continuous emissions rate monitoring system (CERMS)) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if Par fails to appeal as indicated below.

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving Par 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 action as specified in Section 75-2-401, *et seq*., MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by DEQ's decision may request, within 15 days after DEQ renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay DEQ's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the

Board postpones the effective date of DEQ's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, DEQ's decision on the application is final 16 days after DEQ's decision is made.

F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by DEQ at the location of the source.

G. Permit Fee – Pursuant to Section 75-2-220, MCA, failure to pay the annual operation fee by Par may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

H. 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).

Montana Air Quality Permit (MAQP) Analysis
Par Montana LLC – Billings Refinery
MAQP #1564-38

I. Introduction/Process Description

A. Site Location

Par Montana LLC – Billings Refinery (Par) is located in the S½ of Section 24 and the N½ of Section 25, Township 1 North, Range 26 East, Yellowstone County, Montana.

B. Existing Source Description

In addition to regulating Par petroleum refining and storage processes, this permit provides external emission offsets from the Par refinery for the issuance of a permit for an adjacent facility owned and operated by Yellowstone Energy Limited Partnership (YELP), MAQP #2650-01, dated February 14, 1992, and subsequent permits). These offsets are provided by the following requirements contained in this permit: required delivery of all coker process gas stream to YELP any time YELP is operating (Section II, Part A); an hourly limitation on sulfur-in-fuel burned at the refinery (Section II, Part B); and a daily limit on the number of barrels of fuel oil that may be burned at the refinery (Section II, Part C). In addition, to ensure these offsets are enforceable and to protect the integrity of the National Ambient Air Quality Standards (NAAQS) for sulfur dioxide (SO_2), Par is required to provide notice to YELP in the event that it fails to comply with the requirements contained herein concerning either the hourly sulfur-in-fuel limitation (Section II, Part B) or the daily fuel oil firing limit (Section II, Part C). These requirements do not apply when YELP is not operating its facility, since emission offsets are not required (MAQP #1564-03).

This permit includes, but is not limited to, the following equipment:

1. One coke producing coker facility with an associated carbon monoxide (CO) boiler capable of producing steam for use in the general facility.

2. One CO boiler (Coker CO Boiler).

3. All refinery fuel oil and fuel gas-consuming combustion units (i.e., boilers, furnaces, etc.).

4. An 800-ton per day Polymer Modified Asphalt (PMA) unit (928-ton per day including asphalt storage), which includes the following equipment (MAQP #1564-04, modified to improve efficiency in MAQP #1564-17):

   a. Four PMA storage tanks, with external heat exchangers installed to replace internal steam coils (MAQP #1564-17):

      - Tanks #72 & #73 – 973,000 gallons each (approx. 23,000 barrels)

- Tanks #76 & #77 – 207,000 gallons each (approx. 5,000 barrels)

b. One 1966 circulation pump (P-58)

c. One fixed roof wetting/mixing tank (Tank # 960, approx. 265 gallons)

d. One high sheer mill feed pump (ratio pump)

e. One high sheer mill (centrifugal pump) (MAQP #1564-17)

f. Additive injection equipment

g. One sales dispensing pump (P-1A)

h. One PMA service pump

i. One 1948 truck loadout (west rack)

j. Railcar loading for PMA (spots #1, #3 & #5)

k. Various valves and flanges

5. One D-4 drum atmospheric vent stack extension, from 40.8 to 70.1 meters, with added steam injection capability to raise the equivalent height of the stack to 79.2 meters (MAQP #1564-05).

6. One Fluidized Catalytic Cracker (FCC)/CO Boiler stack extension.

7. Tank 26 (Change in the method of operation as part of MAQP #1564-09).

8. Furnace F-1201 (Installed under MAQP #1564-09).

9. Hydrofiner #1 (Modified to produce and segregate Ultralow Sulfur Diesel (ULSD) Products in MAQP #1564-14 and 15).

10. Hydrofiner #3 (Modified to produce and segregate ULSD Products in MAQP #1564-14 and 15).

11. Furnace F-551 (Modified to increase capacity in MAQP #1564-16).

12. Boiler B-8 (Installed under MAQP #1564-26, preconstruction approval for modification for refinery fuel gas reinstated in MAQP #1564-34).

13. Emergency Stationary Engines (Permitted under MAQP #1564-18):

ID No.	Emitting Unit ID	Description	Year in Service	Fuel	Max Horsepower (hp)
SE1	HC/M601	Hydrocracker Backup Power Generator	1986	Diesel	210
SE2	UT/P917B	Cooling Water Return to Alkylation Unit Water Screen (Fire Water)	1998	Diesel	370
SE3	UT/P917A	Cooling Water Return to Alkylation Unit Water Screen (Fire Water)	1998	Diesel	370
SE4	UT/P916	Pond 6 Water to Fire Mains	1991	Diesel	370
SE5	CR/M201	Crude/Coker Backup Power Generator	2002	Diesel	66
SE6	UT/C4	Boiler House Air Compressor	2006	Diesel	475
IEU06	UT/P1A	Fire Water Pump at River Water Pump House	1950	Gasoli ne	230
IEU06	UT/P1B	Fire Water Pump at River Water Pump House	1950	Gasoli ne	230

14. Portable Emergency, Remediation, and Miscellaneous Activity Engines which shall have an Environmental Protection Agency (EPA) certification of Tier 3 or higher (Permitted under MAQP #1564-24, MAQP #1564-27, and MAQP #1564-30):

ID No.	Emitting Unit ID	Description	Original Year in Service	Fuel	Max Horsepower (hp)
SE7	UT/Port1	Boiler House Backup Air Compressor	2011 (may be swapped out)	Diesel	600
SE8	UT/Port2	Boiler House Backup Air Compressor	2011 (may be swapped out)	Diesel	600
SE9	EMES/Eng01	Site Remediation	2011	Diesel	250
SE10	EMES/Eng02	Site Remediation	2011	Diesel	250
SE11	EMES/Eng03	Site Remediation	2011	Diesel	250
SE12*	EMES/Eng04	Miscellaneous Activities	2011	Diesel	500-hp each and 2,100,000 hp-hrs total**
SE13	EMES/Eng05	Emergency and site remediation	2013	Diesel	100
SE14	UT/Port3	SLEB Backup Portable Engine, diesel fired, not to exceed 600 hp	3,000 hr/yr	ARM 17.8.749	SE14

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

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

15. Natural gas-fired residential furnace rated at 10 standard cubic feet per minute used to heat the Operator's Shelter (MAQP #1564-20).

C. Process Description

The Par refinery converts crude oil into various refined products including refinery fuel gas (RFG), liquefied petroleum gas (LPG), aviation fuels, unleaded gasoline, jet fuels, kerosene, diesels, heavy fuel oil, asphalts, and fluid petroleum coke. The following is a brief summary of the petroleum refining process at the Par facility.

Crude oil is generally a mixture of paraffinic, naphtheic, and aromatic hydrocarbons with some impurities including sulfur, nitrogen, oxygen, and metals. Refining at Par begins by physically separating the crude oil constituents into common-boiling-point fractions using three separation processes: atmospheric distillation, vacuum distillation, and light ends recovery. Through various means, residual oils, fuel oils and light ends are converted to gasolines, jet fuels, and diesel fuels; heavier ends are converted to asphalt and coke.

Cracking and coking split large petroleum molecules into smaller ones. The alkylation processes use a catalyst to react small petroleum molecules together to make larger ones. The reforming process rearranges the structure of petroleum molecules to produce higher-octane value molecules of a similar molecule size. Using this conversion process, low-octane naphtha can be converted into high-octane gasoline.

Fuel gas streams containing hydrogen sulfide (H_2S) are typically sent to Montana Sulphur and Chemical Company (MSCC), where they are treated in an amine treatment unit that separates the H_2S from the cleaned fuel gas. The clean fuel is returned to the refinery where it is used in the refinery process heaters and boilers.

D. Permit History

The Billings Exxon Refinery requested a modification to **MAQP #1564A2** to support the YELP permit. The permit modification was given **MAQP #1564-03**. That request was addressed under the provisions of Subchapter 7, Administrative Rules of Montana (ARM) 17.8.733(l)(b).
Exxon proposed to do the following in conjunction with the YELP permit: (1) send all coker process gases to YELP for treatment; (2) change the manner in which the refinery-wide sulfur-in-fuel emission limitation is calculated (daily to hourly) for all fuel-burning units; (3) change the 1.1 pounds per million British thermal units (lb/MMBtu) sulfur limit to 0.96 lb/MMBtu in order to provide sufficient offsets for the YELP facility; (4) cap the refinery fuel oil burning at 720 barrels per day any time YELP is operating both of its boilers; (5) provide additional verification of SO_2 emission reduction by the addition of recording devices on the Coker CO Boiler (KCOB) fuel oil-firing unit and storage fuel oil system, and by utilizing the present emission calculation/accounting procedures at the refinery.

The projected operational changes in Exxon's general Operating MAQP (#1564A) would reduce SO_2 emissions into the Billings airshed. This reduction takes place as a result of the coker process gas emissions, which include SO_2, CO, coke fines, reduced sulfur compounds and nitrogen oxides (NO_X) being sent to YELP for treatment. This is discussed further in the YELP Permit Analysis.

In addition, Exxon proposed no fuel oil burning in the KCOB any time YELP is operating two boilers, plus a commitment to adhere to an hourly sulfur-in-fuel limitation on a refinery-wide basis when YELP is operating both of their boilers.

Adherence to an hourly sulfur-in-fuel limitation was changed from 1.1 to 0.96 lb of sulfur in fuel per million Btu fired. This change was equated to a 100-ton per year offset based on actual SO_2 emissions for the past 2 years. In addition, Exxon committed to a daily refinery fuel oil consumption cap of 720 barrels any time YELP is operating two boilers. This condition was insisted upon by the U.S. EPA because of the difficulty in meeting the federal definition of federally enforceable emission limits. Logic suggested that if the YELP facility was to operate as expected and provided the anticipated steam load to Exxon, a larger reduction in SO_2 emissions would actually be realized because of reduced fuel oil firing at the refinery.

It would be critical for both parties, YELP and Exxon, to coordinate their activities closely once operation of YELP had commenced. The Exxon proposal was based on the attached information and more fully explained the 100-ton per year figure and also the rationale for the block hourly 0.96 lb of sulfur-in-fuel figure calculated on a refinery-wide basis.

Exxon had requested that the Montana Department of Environmental Quality (Department) consider revision of their permit when the new 213-foot stack at MSCC was constructed and made federally enforceable. This increase in stack height lessened MSCC's impact and could have decreased the required offset at Exxon for YELP. DEQ agreed to provide the opportunity for such a revision. However, before Exxon's sulfur-in-fuel limit could be increased, the new 213-foot stack had to be made federally enforceable through a modification of MSCC's Air Quality Permit. Further, DEQ believed the increased stack height may have been necessary to address concerns with the current State Implementation Plan (SIP) and, therefore, may not have been available to reduce the required emission offset at Exxon.

On November 12, 1994, Exxon was issued **MAQP #1564-04** to construct and operate an 800-ton per day PMA unit. The PMA unit would allow Exxon to produce polymerized asphalt.

Conventional asphalt base stock is mixed with solid polymer pellets in a wetting/mixing tank, ground with a sheer mill, and returned to the PMA storage tank. The PMA is then loaded out through existing stubs at the west rack.
No additional steam demand or fuel consumption was necessary for the PMA project. Volatile Organic Compound (VOC) emissions were the primary pollutants of concern; however, all VOC emissions from equipment and tanks in asphalt service were assumed to be negligible since asphalt has negligible vapor pressure at the working temperature seen in the unit.

This alteration also addressed Exxon's August 9, 1994, modification request to replace the strip recorder of the tank gauging device on the fuel oil storage system with a data transmission system inputting to a data acquisition system (DAS). This modification would allow Exxon to use the computer system to collect and archive the fuel data to meet permit conditions.

On August 25, 1995, Exxon was issued **MAQP #1564-05** for a stack extension to the D-4 drum atmospheric vent stack constructed in July 1993. The stack extension raised the height of the D-4 drum atmospheric vent stack from 40.8 meters (134 feet) to 70.1 meters (230 feet). In addition, steam injection capability was added to raise the effective height of the stack to 79.2 meters. The stack extension was designed to eliminate refinery worker exposure impacts during emergencies.

The D-4 atmospheric vent drum was a safety device used to control and manage both routine and abnormal releases from process units. A limited number of safety valves and intermittent blowdowns from the crude, Hydrofiner and coker units were vented to this drum. Inside the drum, a continuous flow of water cooled any safety valve releases or blowdowns to condense vapors for subsequent treatment in the wastewater treatment plant. Any vapors not condensed exited through the D-4 drum atmospheric vent stack.

On January 14, 1996, Exxon was issued **MAQP #1564-06** to construct the FCC/CO Boiler stack extension from 63.4 to 76.7 meters and the F-2 Crude/Vacuum Heater stack from 63.6 to 65 meters. As part of the 1995 proposed Billings/Laurel SO_2 SIP, Exxon and DEQ stipulated that Exxon shall extend the heights of the F-2 Crude/Vacuum Heater and FCC/CO Boiler stacks to at least 65 meters. Exxon was allowed to raise these stacks to above 65 meters but received a Good Engineering Practices (GEP) credit for modeling purposes of 65 meters. Exxon would be entitled to a greater GEP credit for either stack if a physical demonstration (fluid model or field study) was conducted and justified a taller GEP stack height.

On June 17, 1996, DEQ issued **MAQP #1564-07** to modify the opacity limitations for the wetting/mixing tank exhaust vent in the PMA unit. The requirements of 40 CFR 60, Standards of Performance for New Stationary Sources (NSPS), Subpart UU – Standards of Performance for Asphalt processing and Asphalt Roofing Manufacture, were reviewed during the initial permit review and it was determined that this subpart was not applicable to the wetting/mixing tank because the tank was used for mixing only and did not store asphalt; therefore, it did not meet the definition of a storage tank. The opacity limit set in the original permit, however, was representative of an asphalt tank that was used for storage of asphalt as defined under NSPS, Subpart UU. The permitted opacity limit did not recognize the fact that mixing asphalt is occurring in the mixing tank. Due to mixing, there may have been a noticeable opacity at the wetting/mixing tank top, even when mixing temperatures were well below 400^{o} F.

A 20% opacity limit was set to reflect the effects of minor mixing in the wetting/mixing tank, which was consistent with ARM 17.8.304 (2). This rule required 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.

Exxon would still need to maintain the operating temperature of the wetting/mixing tank below the smoking point of asphalt in order to comply with the 20% opacity limit. The wetting/mixing tank only operates intermittently during the summer asphalt season. Any opacity is localized inside the refinery and does not create a public nuisance.

On April 9, 1999, DEQ received a request to modify Exxon's MAQP #1564-07 to bring the permit closer to the requirements of the June 12, 1998, stipulation between Exxon, DEQ, and the Board of Environmental Review (Board). The changes reduced the reporting and recordkeeping burden for both Exxon and DEQ, updated the permit with current rule references, and consolidated all the previously issued permits to Exxon in **MAQP #1564-08**.

Exxon also holds a permit for the bulk marketing distribution terminal located adjacent to the refinery. Although the refinery and bulk terminal hold separate preconstruction permits, for any Prevention of Significant Deterioration (PSD) permitting action, the refinery and bulk terminal are considered one facility and must be evaluated as such for any emission increases or decreases.

MAQP #1564-08 replaced MAQP #1564-07 and all permits identified in Table I.2 of MAQP #1564-08.

On July 1, 1997, Exxon applied via MAQP Application #1564-08a to construct a sulfur processing facility to be located at the Billings refinery. Exxon was the applicant, with TRC Consultants performing the Best Available Control Technology (BACT)/regulatory analysis and the modeling impact analysis. DEQ requested additional permitting information and clarification on July 31, 1997. Formal responses to the original deficiencies were received on September 4, 1997, and a confidential package, protected under court order, was received on October 2, 1997. Exxon transfers via pipeline, sour fuel gas and acid gas (H_2S) to the MSCC facility located adjacent to the refinery. The proposed sulfur processing facility would have eliminated the need to send the gases off site and would have enabled Exxon to treat the sour fuel gas and acid gas streams and produce sulfur as a marketable product.

On October 7, 1997, DEQ was informed that Exxon had signed a multi-year contract with MSCC and the project was on hold. On October 16, 1997, Exxon requested a meeting with DEQ to formally withdraw the permit application and request that all materials submitted in support of the application be returned to Exxon. The material was to include all volumes of the application submittals and the package of confidential business information submitted on October 2, 1997. On October 22, 1997, DEQ sent a letter to acknowledge the official withdrawal of Application #1564-08a and to inform Exxon that the materials submitted in support of the application would not be returned to Exxon. DEQ's legal staff had confirmed that the public record must be preserved, and the materials could not be returned to the applicant.

On August 21, 2000, Exxon submitted a permit application to DEQ, with additional submittals on November 13, 2000, and November 22, 2000. The submittals requested the following changes to MAQP #1564-08:

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

2. Allowance for the modification of furnace F-700 to increase its firing capability from 105.6 MMBtu/hr to 122 MMBtu/hr; and

3. Modification to the method of operation of Tank 26 to reduce volatilization of the stored petroleum product;

4. A name change, from Exxon Company U.S.A. to ExxonMobil Corporation (received January 7, 2000);

5. Clarification of new operating temperature used in Section II.E.1. The description of the operating temperature was changed from "minimum operating temperature" to "operating temperature of the wetting/mixing tank below the smoking point of asphalt";

6. Attachment of the letter dated September 25, 1989, which specifies the monitoring procedures (Appendix A) to be used for the permit (the above letter was previously referenced for monitoring procedures).

The requirements contained in Section II, Parts B and C, concerning an hourly limitation on sulfur in fuel and a daily limitation on fuel oil firing, respectively, apply on a refinery-wide basis to all fuel-burning units at the refinery, consistent with the 1977 Stipulation. **MAQP #1564-09** reflected all of the above changes and replaced MAQP #1564-08.

MAQP #1564-10 was not issued. Two applications were received within the same time period to alter MAQP #1564-09 and were not issued in the order in which they were received. To avoid confusion in referencing these permit applications and actions, MAQP #1564-10 was removed from use.

On March 3, 2001, DEQ issued a permit for the installation and operation of two temporary aero-derivative jet engine electricity generators (Model LM1500), each capable of generating approximately 10 megawatts of power, and an accompanying diesel storage tank. These generators were necessary because of the high cost of electricity. The operation of the generators would not occur beyond 2 years and was not expected to last for an extended period of time, but rather only for the length of time necessary for ExxonMobil to acquire a more economical supply of power.

Because these generators would only be used when commercial power was too expensive to obtain, the amount of emissions expected during the actual operation of these generators was minor. In addition, the installation of these generators qualified as a "temporary source" under the PSD permitting program because the permit limited the operation of these generators to a time period of less than 2 years. Therefore, ExxonMobil was not required to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators were considered temporary, DEQ required compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 was ensured. In addition, ExxonMobil was responsible for complying with all applicable air quality standards. **MAQP #1564-11** replaced MAQP #1564-09.

On May 16, 2001, DEQ issued a permit for the installation and operation of a temporary aero-derivative jet engine electricity generator (Model LM1500), capable of generating approximately 10 megawatts of power. This generator would be used in addition to the two similar generators permitted in #1564-11 and would be considered a part of the same project with respect to time constraints. This generator and the two generators previously permitted are necessary because of the high cost of electricity. The operation of the generators will not occur beyond 2 years and is not expected to last for an extended period of time, but rather only for the length of time necessary for ExxonMobil to acquire a more economical supply of power.

As previously mentioned, because the generators will only be used when commercial power is too expensive to obtain, the amount of emissions expected during the actual operation of the generators is minor. In addition, the installation of the generators qualifies as a "temporary source" under the PSD permitting program because the permit will limit the operation of the generators to a time period of less than 2 years. Therefore, ExxonMobil will not need to comply with ARM 17.8.804, 17.8.820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, DEQ requires compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 will be ensured. In addition, ExxonMobil is responsible for complying with all applicable air quality standards. **MAQP #1564-12** replaced MAQP #1564-11.

On February 13, 2002, DEQ received a permit application to address emission increases associated with the modifications that allowed approximately 500 barrels per day more fresh feed to be processed through the Fluid Coker unit (Coker). Other units/processes that were affected by the proposed modifications included the fluidized catalytic cracking unit (FCCU), the motor gasoline (mogas) storage tank throughputs, and the refinery fuel gas system throughput.
Included in this permitting action was a limit on refinery-wide fuel oil combustion used to keep the overall SO_2 emissions increase from the project below PSD SO_2 significance levels. In addition, a contemporaneous decrease in VOC emissions on Tank #309 offset the increase in VOC emissions from the project, to keep the project below PSD VOC significance levels.

The project involved the following activities (not all of them requiring permitting, but all included in the application as they relate to the overall project):

1. Replace the existing product coke line with a larger diameter pipe and remove a number of bends and turns to decrease piping pressure drop. Line size increased from 6 inch to 8 inch in diameter and allowed for a product coke capacity of approximately 550 tons per day. This line connects from the Coker unit to the BGI coke silo (capacity related);

2. Upgraded the gearbox of the Coker light ends compressor to facilitate compressing the increased volume of light ends from the higher throughput at the Coker. This compressor (C-311) is located in the refinery Gas

Compressor Building near the north end of the FCCU facility (capacity related);

3. Installed new steam aeration nozzles and replaced appropriate sections of the scouring coke line from the Coker burner to the reactor. This allowed improved coke circulation and allowed ExxonMobil to avoid excessive coke buildup at the Coker area (maintenance related);

4. Installed a multi-hole orifice chamber in the Coker Process Gas line that goes to either BGI or the Coker CO Boiler. This device stabilized the back-pressure that the slide valves, located on the top of the Coker burner vessel, have to control. This device allowed smoother transition in unit operations whenever the Coker Process Gas must be diverted away from BGI and back to the Coker CO Boiler (maintenance and capacity related);

5. Modified the cyclone outlet from the Coker reactor to the scrubber section to a newer design, which has a custom designed elbow and larger horn (outlet), decreasing the velocity and pressure drop through the cycle to accommodate an increased vapor rate. The cyclone is located at the top of the Coker reactor outlet and carries reactor hydrocarbon vapors into the scrubber section of the vessel (capacity related);

6. Modified the internals of the D-202 Coker Fractionator Overhead receiver drum to improve liquid/vapor separation. This drum is located at the Coker unit (capacity related);

7. Modified the Coker reactor feed pumps and drivers to increase capacity to match the 500 barrel per day unit increase and higher discharge pressure requirements. The reactor feed pumps take oil from the scrubber and recycle this liquid back to the feed surge drum and supply the reactor feed nozzles. By increasing the speed of the pump impellers, both pressure and increased capacity requirements are satisfied without having to replace the pumps. The bearing housings would be upgraded, if necessary, to safely achieve these higher speeds (capacity related);

8. Modified the reactor feed nozzle system with an improved design. The intent of these changes was to optimize the Coker unit feed nozzle system operation (capacity related); and

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

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

On October 22, 2003, DEQ received a MAQP Application from ExxonMobil to modify MAQP #1564-13 to meet the EPA 15 parts per million (ppm) sulfur standard for highway diesel fuel. On December 4, 2003, DEQ deemed the application complete. Units/processes that were affected by the proposed modifications included the Kerosene Hydrofiner (Hydrofiner No. 3), Diesel Hydrofiner (Hydrofiner No. 1), new facilities to segregate Hydrocracker diesel from Hydrofiner No. 1 diesel, and modifications and additions to facilities to segregate highway and off-road No. 2 diesel fuels. The modifications resulted in an increase in throughput through the FCCU and an increase on motor gas (mogas) production. This permitting action resulted in a limit on refinery-wide fuel oil combustion so that the overall SO_2 emissions increase from the project would stay below the PSD SO_2 significance levels. The permit action took out all references to the temporary generators that were previously permitted and were removed from the facility. The equation for Tank 26 was updated to more accurately account for temperature and pressure in the calculation of VOC emissions for Tank 26. **MAQP #1564-14** replaced MAQP #1564-13.

On April 9, 2004, DEQ received a MAQP Application from ExxonMobil to modify MAQP #1564-14 for changes in how ExxonMobil planned to meet the EPA's 15 ppm sulfur standard for highway diesel fuel. Units/processes affected by the proposed modifications included the addition of a lubricity facility and the addition of minor piping. ExxonMobil no longer planned to segregate Hydrocracker diesel from Hydrofiner No. 1 diesel, or to segregate highway and off-road No. 2 diesel fuels. The current modification resulted in an increase in throughput through the FCCU, an increase in mogas production, an increase at the Hydrogen Unit, and an increase in throughput at the marketing terminal.
The permitting action resulted in a limit on refinery-wide fuel oil combustion so that the overall SO_2 and particulate matter (PM) emissions increase from the project would stay below the PSD SO_2 and PM significance levels. **MAQP #1564-15** replaced MAQP #1564-14.

On February 9, 2005, DEQ received a complete MAQP Application from ExxonMobil to modify MAQP #1564-15. The purpose of the application was to address the replacement of six existing convection section tubes with six new finned convection section tubes in the Steam Reforming Furnace (F-551) located in the Hydrogen Plant. Replacing and finning the upper tube row in the secondary preheat coil of F-551 allowed for improved heat absorption from the process stream which in turn results in improved Hydrogen Plant production. The modifications directly affected F-551 and, potentially, indirectly increased throughput to the FCCU, Alkylation Unit, Powerformer Unit, and Hydrocracker Unit. Crude oil throughput did not increase as a result of the modification. The permitting action resulted in lowering the existing limit on refinery-wide fuel oil combustion so that the overall SO_2 and PM emissions increase from the project was below the PSD SO_2 and PM significance levels. Section II.F.2 of the Permit Analysis (MAQP #1564-16) included a discussion of the netting analysis conducted for the permit action. **MAQP #1564-16** replaced MAQP #1564-15.

On September 22, 2005, DEQ received a complete MAQP Application from ExxonMobil to modify MAQP #1564-16. Further information was received in a letter from ExxonMobil dated October 20, 2005. The purpose of this application was to address several projects impacting the PMA unit. ExxonMobil proposed modifications to the PMA process unit and addition of a new PMA railcar loading in order to create more PMA from a historical production rate of 300 – 600 barrels/day, to 5000 barrels/day PMA, and to allow PMA loading of railcars. In addition, on October 19, 2005, DEQ received a request for an Administrative Amendment to allow the use of Method ASTM D1298 for determining the API gravity of fuel oil. These permit actions were combined. **MAQP #1564-17** replaced MAQP #1564-16.

On October 5, 2005, DEQ received a MAQP Application from ExxonMobil to incorporate the following emergency stationary engines into MAQP #1564-17: five existing diesel-fired engines; one new diesel-fired engine; and two existing gasoline-fired engines. After receiving additional submittals from ExxonMobil, DEQ determined that the application was complete on February 17, 2006. **MAQP #1564-18** replaced MAQP #1564-17.

DEQ received the following two de minimis notifications and two administrative amendment requests from ExxonMobil:

- 12/22/05 – CHUB-Amine and Fluidized Catalytic Cracking (FCC) Unit de minimis notification (no permit changes required).

- 1/11/06 – Administrative Amendment request to eliminate fuel oil monitoring requirements, based on elimination of fuel oil firing at the refinery;
- 4/5/06 – Administrative Amendment request to incorporate Consent Decree requirements; and

- 2/9/07 – De minimis notification for addition of Selective Catalytic Reduction (SCR) to FCC Unit Carbon Monoxide (CO) boiler and treat Sour Water Stripper (SWS) overhead to meet Consent Decree requirements (no permit changes required).

In addition to modifying the permit as necessary per the aforementioned de minimis notifications and administrative amendment requests, Section II of the permit was also reorganized, and extraneous permit conditions were eliminated. **MAQP #1564-19** replaced MAQP #1564-18.

On February 28, 2008, a de minimis notification was received proposing process modifications in order to achieve emission reductions mandated by the US EPA Consent Decree (CD). The notification proposed the following process modifications:

1. Nitrogen Oxide (NO_x) control – proposal to install a third catalyst bed to the Selective Catalytic Reduction (SCR) unit on the FCCU Carbon Monoxide Boiler (COB) in order to meet the requirements of ExxonMobil's CD, Paragraph 17a. This proposal supersedes the May 8, 2006, notification for installation of a Thermal $DeNO_x$ system and Ultralow NO_x Burners, and is a modification and update of the February 9, 2007, notification for the installation of the SCR on the FCCU and FCCU COB.

2. Proposal to remove the five existing soot blowers and replace with 17 new soot blowers to assist with boiler tube fouling and increased temperatures in the boiler.

3. Proposal to replace air blowers for FCCU COB to help maintain current boiler capabilities at increased operating pressure.

4. SO_2 control – proposal to treat the Sour Water Stripper (T-23) overhead gas (SWS Overhead Project) with hydrogen peroxide treatment, in order to meet Subpart A and J requirements as mandated by the CD paragraph 59. This supersedes the February 9, 2007, proposal to treat the SWS overhead gas with caustic wash treatment.

On April 15, 2008, a de minimis notification was received proposing the following process modifications mandated by the US EPA CD that requires ExxonMobil to comply with the NSPS, 40 CFR 60, Subparts A and J for the main flare and turnaround flare:

1. Flare Gas Recovery (FGR) Unit – modifications to existing FGR unit, including a proposal to install a two-stage dry helical screw compressor to pressurize the flare gas and to allow gas to be sent to MSCC.

2. Sweet Fuel Gas Letdown Facilities – proposal to add a sweet fuel gas letdown line with associated knock out (KO) drum to allow flaring of the sweet fuel gas in the event that MSCC is shut down.

3. Connection between J-901 and C-311 – proposal to use the J-901 Flare Gas Eductor to recover flare gas into C-310 FCC Wet Gas Compressor in the event that the FGR unit is shut down. In addition, ExxonMobil proposed to add new piping to recover flare gas from J-901 into C-311 Coker Gas Compressor if both the FGR unit and the FCCU are shutdown.

4. H_2S continuous emission monitoring system (CEMS) – proposal to add a CEMS to the flare header to monitor H_2S concentration of the gas sent to either the turnaround flare or the main flare.

5. Unsaturated Light Ends (ULEB) Unit – modification to ULEB unit to mitigate potential flaring events, including: replacement of safety valves on the Unsaturated Caustic Prewash Drum D-326 and Unsaturated Caustic Settling Drum D-327; addition of a sleeve/dipleg added to D-327, and the addition of high pressure alarms on the two DEA regenerator towers (T-305 and T-607).

6. Modification to D-942 Seal Drum – modify or replace the existing sparger in the D-942 Seal drum to increase the existing 12-inch glycol seal to between 18 and 24 inches.

On June 19, 2008, a de minimis notification was received for operation of a natural gas furnace in a new Operation and Control Center Building. The natural gas fired residential furnace is rated at 10 standard cubic feet per minute (scfm) resulting in potential emissions significantly less than 15 tons per year (TPY).

On November 24, 2008, an Administrative Amendment request was received proposing inclusion of language in the permit signifying modified or the potential to modify CD deadlines as negotiated by ExxonMobil. **MAQP #1564-20** replaced MAQP #1564-19.

On July 6, 2009, (with additional information received on August 11, 2009), DEQ received a request from ExxonMobil to modify MAQP #1564-20 to reflect decommissioning of the existing B-8 boiler, construction and operation of a temporary natural gas-fired boiler for a period of up to twelve months, and construction of a new permanent B-8 natural gas and/or refinery fuel gas-fired boiler.

The decommissioning of the existing B-8 boiler is part of a NO_x reduction strategy as required by the US EPA Consent Decree (United States et al. v. ExxonMobil Corporation et al., dated December 13, 2005).

In addition to making the requested change, DEQ deleted all references to 40 CFR 63, Subpart DDDDD: NESHAP for Industrial, Commercial, and Institutional Boilers and Process Heaters, as it was removed from the ARM in October 2008 following a federal court vacature. **MAQP #1564-21** replaced MAQP #1564-20.

On December 18, 2009, DEQ received a request from ExxonMobil to administratively amend their current permit to clarify permit conditions contained in MAQP #1564-21, specifically pertaining to a temporary B-8 boiler (B-8 Temp). Inadvertently, a portion of the conditions identified in MAQP #1564-21 for B-8 Temp were incorrectly stated. Specifically, these conditions pertain to operational time frames of B-8 Temp and also the existing B-8 boiler. The changes were incorporated into MAQP #1564-22.

On December 24, 2009, DEQ received an Application for an Air Quality Permit Modification from ExxonMobil to incorporate modifications to MAQP #1564-21. The requested changes included the addition of new fugitive volatile organic compound (VOC) components and a modification to compressor C-310. Because of the uncertainty associated with the current Montana de minimis rule (ARM 17.8.745) with respect to the rule having not yet been approved by EPA into Montana's State Implementation Plan (SIP) and the need to comply with internal company policy, ExxonMobil chose to group future VOC fugitive component additions and apply for a permit modification on that basis instead of using ARM 17.8.745 when such components were added in smaller increments and associated with separate projects.

In order to meet requirements outlined within the EPA Consent Decree (CD) (United States et al. v. ExxonMobil Corporation *et al.*, dated December 13, 2005), ExxonMobil intends to install a larger second eductor (J-902) for flare gas management. The gas to operate J-902 will come from C-310. The increase of flare gas recovery associated with J-902 will result in a decrease of C-310 gas compression from the fluidized catalytic cracking unit (FCCU), which in turn will decrease FCCU capacity. In order to recover this lost FCCU capacity, the proposed project was to install a new, larger C-310. In April 2009, a de minimis request was approved for a modification to this unit. ExxonMobil had changed the scope of the project to install a new unit. **MAQP #1564-22** replaced MAQP #1564-21.

On May 17, 2010, DEQ received a request from ExxonMobil to administratively amend their current permit to include applicable requirements contained in paragraphs 70, 71, and 73 of the EPA Consent Decree (CD) (United States et al. v. ExxonMobil Corporation et al., dated December 13, 2005) and the amendments to the CD filed on January 26, 2009. Paragraph 145 of the CD requires permit limits outlined within paragraphs 70, 71, and 73 to survive the termination of the CD. This permit action incorporated these specific limits. **MAQP #1564-23** replaced MAQP #1564-22.

On April 29, 2011, DEQ received an Application for an Air Quality Permit Modification from ExxonMobil to incorporate a number of different portable diesel engines certified to EPA Tier 3 emission standards into the MAQP.
The application included proposed limits on annual hours of operation for some of the proposed engines in order to keep the combined emissions from the permitting action below any New Source Review (NSR)/Prevention of Significant Deterioration (PSD) major source modification significant emission rate (SER) thresholds. DEQ replied with an incompleteness letter on June 7, 2011, indicating that the engine emissions needed to be based on the most conservative Tier 3 standards based on the proposed permit conditions. ExxonMobil responded with a letter received June 29, 2011, that addressed the issues presented in the Incompleteness Letter. The proposed engines and operating conditions were as follows:

- Project #1: Add two portable emergency backup diesel engines not to exceed 500-hp each and limited to 1,500 hours per year each that are certified to EPA Tier 3 emission standards or better. These engines are likely to drive either air compressors or electric generators and would be used as emergency backup engines to existing electrical equipment.

- Project #2: Add three portable remediation activity diesel engines not to exceed 250-hp each with no limits on annual hours of operation that are certified to EPA Tier 3 emission standards or better. These engines would likely drive either air compressors or other equipment used for remediation projects.

- Project #3: Add miscellaneous portable diesel engines not to exceed 500-hp each and limited to a combined 2,100,000-brake horsepower-hours (hp-hrs) per year that are certified to EPA Tier 3 emission standards or better. In order to maximize operational flexibility, ExxonMobil proposed a limit on total hp-hrs rather than annual hour limits for each engine. Hp-hrs is equal to the engine's maximum rated hp multiplied by the actual hours of operation. The sum of the hp-hrs from each engine in Project #3 would be limited to 2,100,000-hp-hrs.

These portable limited-use engines would likely drive either air compressors or electrical generators on an as-needed basis.

This permit action incorporated these engines and conditions. **MAQP #1564-24** replaced MAQP #1564-23.

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

To provide background information, on December 24, 2009, DEQ received an application for an Air Quality Permit Modification from ExxonMobil to incorporate modifications to MAQP #1564-21. The requested changes included the addition of new VOC components. Because of the uncertainty associated with the current Montana de minimis rule (ARM 17.8.745) with respect to the rule having not yet been approved by EPA into Montana's SIP and the need to comply with internal company policy, ExxonMobil chose to group future VOC fugitive component additions and apply for a permit modification on that basis instead of using ARM 17.8.745 when such components were added in smaller increments and associated with separate projects.

On February 13, 2012, the EPA took final action to approve the de minimis rule into the SIP (FR Vol. 77, No. 29, pg. 7531-7534). As a result, ExxonMobil has requested DEQ to remove permit conditions associated with installation, monitoring, and reporting of new fugitive VOC components. The permit action removed these permit conditions. **MAQP #1564-25** replaced MAQP #1564-24.

On August 6, 2012, DEQ received correspondence from ExxonMobil requesting that DEQ amend the MAQP to change the emitting unit ID and description of the portable diesel-fired air compressor engine SE8 from "SLEB Backup Air Compressor (SL/Port2)" to "Boiler House Backup Air Compressor (UT/Port2)". The compressor was originally located at the SLEB unit but will now be located at the boiler house. This permit action changes the emitting unit ID and description for SE8. **MAQP #1564-26** replaced MAQP #1564-25.

On January 28, 2013, DEQ received a request to amend MAQP #1564-26. The permitting action added a portable, 100-brake horsepower, Tier 3, diesel-fired engine to be used for emergency backup and to assist with on-going remediation efforts. This action added the emitting unit ID (SE13) with a description of the portable diesel-fired engine, and updated permit language. **MAQP #1564-27** replaced MAQP #1564-26.

On November 27, 2013, DEQ received a request to modify MAQP #1564-27. The current action permits an increase in maximum allowable horsepower of two diesel-fired engines utilized for air compression from 500 brake horsepower to 600 brake horsepower. These engines are emergency backup units to existing equipment. These engines are intended to be permitted in a flexible manner to allow for any engine meeting the designated emissions standards, up to the maximum rated horsepower assigned, to be utilized. This was to include swapping out of engines as necessary.

The engines are known as the SE7 and SE8 engines. **MAQP #1564-28** replaced MAQP #1564-27.

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

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

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

MAQP #1564-29 replaced MAQP #1564-28

On February 4, 2015, DEQ received from ExxonMobil an application for modification of the MAQP in regard to the B-8 Boiler, and for addition of a new 600 horsepower portable diesel fired engine.

The B-8 Boiler was originally permitted in October 2009 under MAQP #1564-21 to combust refinery fuel gas as well as natural gas, and was installed as part of NO_X reductions required by consent decree. ExxonMobil originally requested permitting this boiler with flexibility to burn natural gas or refinery fuel gas. Because ExxonMobil never installed capability to burn refinery fuel gas, preconstruction permit timeframes allowing for this construction passed. At ExxonMobil's request, preconstruction approval was renewed to allow ExxonMobil to burn refinery fuel gas in the boiler.

Although specification sheets for the boiler indicate the boiler is physically designed for a maximum firing rate of less than 99 million British thermal units per hour (MMBtu/hr), ExxonMobil has requested, and DEQ has provided, limitation on the maximum MMBtu/hr rate which can be fired in the B-8 Boiler, at 99 MMBtu/hr. The heat input at 100% firing rate is presented in the application via specification sheet as 91 MMBtu/hr and 88.8 MMBtu/hr for natural gas and refinery fuel gas, respectively.

ExxonMobil also requested the addition of a portable diesel engine, referred to as SE14. The engine would be a rental and would provide backup power for air compression for supplying the refinery with instrument quality compressed air.

ExxonMobil proposed the engine not exceed a maximum rated horsepower of 600, an operational limitation on operation of 3,000 hours per year, and that the engine meet a minimum EPA Tier 3 certification. The engine is expected to be used as an emergency backup engine. **MAQP #1564-30** replaced MAQP #1564-29.

On April 28, 2015, DEQ received from ExxonMobil an administrative amendment request. Section II.A.7.b originates from consent decree language and did not fully capture the entire language provided in the consent decree. Specifically, ExxonMobil requested that the option to re-route sour water stripping unit overhead gas be reinstated in this permit condition. The action incorporated ExxonMobil's request. **MAQP #1564-31** replaced MAQP #1564-30.

On March 8, 2018, DEQ received from ExxonMobil an application to re-instate preconstruction authority for Boiler B-8 (Standby Boiler-House) to fire refinery fuel gas in addition to purchased natural gas. This boiler had previously been permitted in April 2015 to combust refinery fuel gas, however, construction of piping infrastructure to include refinery fuel gas did not commence within three years of that preconstruction authorization.

Therefore, ExxonMobil submitted application to re-instate the preconstruction authorization. A full Best Available Control Technology review as well as review for any updates on applicable requirements was made. This permitting action authorized combustion of refinery fuel gas in Boiler B-8, with **MAQP #1564-32** replacing MAQP #1564-31.

On April 14, 2020, DEQ received from ExxonMobil an application to modify the MAQP to ensure coverage of repair to twelve existing storage tanks which may exceed the routine maintenance, repair, or replacement exemption under ARM 17.8.744. ARM 17.8.740 defines routine maintenance, repair, or replacement as excluding activities with fixed capital cost exceeding 50% of the fixed capital cost necessary to construct a comparable, entirely new emitting unit; that change the design of the emitting unit; or that increase the potential to emit of the emitting unit. New conditions were located in Section II.J. **MAQP #1564-33** replaced MAQP #1564-32.

On March 31, 2021, DEQ received from ExxonMobil an application to re-instate preconstruction authority for Boiler B-8 (Standby Boiler-House) to fire refinery fuel gas in addition to purchased natural gas.

This boiler had previously been permitted in May of 2018 to combust refinery fuel gas, however, construction of piping infrastructure to include refinery fuel gas did not commence within three years of that preconstruction authorization. Therefore, ExxonMobil submitted an application to re-instate the preconstruction authorization. A full Best Available Control Technology review is conducted as well as review for any updates on applicable requirements. **MAQP #1564-34** replaced MAQP #1564-33.

On August 20, 2021, DEQ received a request from ExxonMobil to incorporate emissions limits on the Fluid Catalytic Cracking Unit. The limits reflected an

Environmental Protection Agency (EPA) determination of a final SO_2 limit as required by a consent decree. **MAQP#1564-35** replaced MAQP #1564-34.

On June 23, 2022, DEQ received an administrative amendment request from ExxonMobil for the removal of reference to United States, et al. v. Exxon Mobil Corporation, et. Al, Consent Decree requirements withing the MAQP. **MAQP #1564-36** replaced MAQP #1564-35.

On March 3, 2023, the Montana Department of Environmental Quality – Air Quality Bureau (DEQ) received an Intent to Transfer Ownership notification from Par Montana, LLC., to transfer ownership of the Billings Refinery from ExxonMobil Fuels and Lubricants Company to Par Montana, LLC. The transfer ownership was dated June 1, 2023. Along with the transfer of ownership, DEQ updated references throughout the permit. **MAQP #1564-37** replaced MAQP #1564-36.

E. Current Permit Action

On December 20, 2024, DEQ received an application for permit modification from Tetra Tech, Inc., on behalf of Par to address changes to the Crude Furnace (F-1) to improve efficiency primarily through updating tube design within the furnace building. The changes to F-1 include refractory repair or replacement if needed, burner replacement with "in-kind" modern models, and replacement of tubing within the F-1 house with homogenous pipelines fitted with "finned tubes" to improve thermal efficiency.

The 2-year baseline emissions data from September 2019 through August 2021, which is more representative of normal operations throughout the facility was used for determining PSD applicability. DEQ has reviewed the proposed baseline and determined it is an appropriate two-year period for a baseline.

The increase in emissions from the proposed updates does not trigger a PSD action based on the limited amounts of emissions generated from the increase in operating hours and fuel usage. DEQ updated the Refineries physical address. **MAQP #1564-38** replaces MAQP #1564-37.

F. Response to Public Comment

Person/Group Commenting	Permit Reference	Comment	DEQ Response
Tetra Tech on behalf of Par Montana	MAQP - Section 1.A	Par requests both "Issued to" address and Section I.A – Plant Location be updated to read: 700 Par Montana Road, Billings, MT 59101.	Thank you for your comment. DEQ made the requested change.
	MAQP - Section II.A.7a	Par requests an update to this table to include E01a – F-2 (F-1 & F-401) on the table of affected facilities under the 40 CFR 60, Subpart J – Fuel Gas Combustion Devices table.	Thank you for your comment. DEQ made the requested change.

	MAQP - Section II.N.4	Clarify that the natural gas is burned only in the burner pilots for F-1, refinery fuel gas is the main fuel. Suggested language: "Par shall burn only natural gas or refinery fuel gas in F-1 (natural gas is used only in the burner pilots, RFG is the main burner fuel) (ARM 17.8.749, 17.8.752)."	Thank you for your comment. DEQ made the requested change to read, "Par shall burn only natural gas for the pilot light and refinery fuel gas for the main burners in F-1".
	MAQP - Section II.P.12	Correct the NOx limit reference for F-1 from Section II.A.18 to Section II.N.1.	Thank you for your comment. DEQ made the requested change.
	MAQP Analysis - Section I.E	Current Permit Action – Par requests the language "pipelines fitted with "wings"" be replaced with "finned tubes." Also, please capitalize "Refinery" in the statement referring to the address update.	Thank you for your comment. DEQ made the requested change.
	MAQP Analysis – Section II.B	Current Permit Action – Par requests the language "pipelines fitted with "wings"" be replaced with "finned tubes." Also, please capitalize "Refinery" in the statement referring to the address update.	Thank you for your comment. DEQ made the requested change.
	MAQP Analysis – Section II.B.	ARM 17.8, Subchapter 3, Section 7.f – Please add 40 CFR 63, Subpart DDDDD – NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters as an applicable requirement. It is already an applicable requirement to units at the Refinery. The project does not change that applicability or trigger new requirements.	Thank you for your comment. DEQ made the requested change.
	MAQP Analysis – Section II.D.1	ARM 17.8.504 – Par requests the last sentence of this paragraph be replaced with, "Par submitted the appropriate permit application fee for the current permit action."	Thank you for your comment. DEQ made the requested change.
	MAQP Analysis – Section II.E.5	Par requests that the last sentence under (1) be updated to state that "Par submitted the required permit application for the current permit action." Similarly, Par also requests the last sentence under paragraph (2) be updated to state that "Par submitted an affidavit of publication of public notice for the December 12, 2024, issue of	Thank you for your comment. DEQ made the requested change.

		The Billings Gazette, a newspaper of general circulation in the town of Billings, Montana, Yellowstone County.	
	MAQP Analysis – Section II.F.2	ARM 17.8.818, Par requests that the last sentence of this description be updated to state, “Par's existing petroleum refinery in Billings is defined as a "major stationary source" because it is a listed source with a PTE more than 100 tons per year of several pollutants (PM, SO2, NOx, CO, and VOCs). This action did not exceed the significant emissions rates associated with a major modification and is therefore, not subject to PSD.”	Thank you for your comment. DEQ made the requested change.
	MAQP Analysis – Section III	BACT Analysis. Under Step 1, correct “Fuel” gas recirculation to “Flue” gas recirculation.	Thank you for your comment. DEQ made the requested change.
	MAQP Analysis – Section V	Existing Air Quality. Because the Billings SO2 Nonattainment Area was redesignated to attainment, Par requests that the last sentence be updated to state “the Laurel SO2 Nonattainment Area is approximately 19 miles away.”	Thank you for your comment. DEQ made the requested change.
	Environmental Assessment (EA) – Proposed Action and Section 3	Par requests that the F-1 fuel reference to natural gas be specified to reflect that the pilots for the burners fire natural gas but the main burners fire RFG.	Thank you for your comment. DEQ made the requested change.
	EA – Table 1 and Section 12	Industrial, Commercial and Agricultural Activities and Production; in Section 24 – Greenhouse Gas Assessment; and in Conclusions and Findings, Par requests the language “crude pipes with fins attached” be replaced with “finned tubes.”	Thank you for your comment. DEQ made the requested change.
	EA – Section 3	Air Quality, Par requests the fuel usage to be corrected from MMBtu/yr to MMscf/yr in the following sentence: “The emission inventory for the proposed project is based on a yearly increase in operating hours for the crude furnace from 8,415 hours per year up to 8,741 hours per year and an increase in natural gas from 1331.5	Thank you for your comment. DEQ made the requested change.

		MMBtu per year to 1384.7 **MMBtu per year**."	
	EA – Section 24	Greenhouse Gas Assessment, Par requests the fuel usage to be corrected from MMBtu/yr to MMscf/yr in the following sentence: "The GHG emissions were calculated from the proposed projects operations increase of 336 hours per year and fuel increase of 53.2 **million British thermal units per year**."	Thank you for your comment. DEQ made the requested change.
	EA – Conclusions and Findings	Par requests that the reference to operating "engines" be updated to "F-1 Furnace."	Thank you for your comment. DEQ made the requested change.
Western Environmental Law Center on behalf of the Montana Environmental Information Center	EA – Section 24. Green House Gas Assessment	Direct Impacts. DEQ constrained its analysis of direct impacts to conducting a rudimentary quantification of the GHG emissions associated with the proposed increase in operational hours of 336 hours per year and the associated fuel increase.21 Plugging these values into the EPA's Simplified GHG Calculator, the Draft EA provides "a maximum of 2,896.3 metric tons of CO2e would be produced per year of operation."22 That is all the Draft EA discloses with regard to direct impacts from the refinery. Instead of merely quantifying the value with no context, DEQ must also analyze the effects of these emissions, taking into account the undisputed fact that each additional ton of GHG emissions exacerbates climate impacts.23	Thank you for your comment. Section 24 of the EA documents the expected project-specific CO2e emissions, and the tools and analysis used in the EA to disclose CO2e. DEQ disagrees with the commenters suggestion that the analysis provides a rudimentary quantification of GHG emissions associated with the proposed action. Impacts from GHG emissions are generally characterized as global in nature (i.e., global climate change) and there is little evidence to suggest that localized, direct impacts from CO2e emitted within the analysis area would impact the atmosphere and climate at a local scale. Rather, the expected impacts would occur as Secondary and Cumulative Impacts, as defined by MEPA. When industrial

			greenhouse gases are emitted into the atmosphere from the proposed action (and other nearby related facility operations), they become well-mixed globally due to their long lifetimes in the atmosphere (i.e., tens of years for methane to thousands of years for carbon dioxide) and atmospheric mixing, primarily driven by differential heating and synoptic-scale weather patterns, which distribute the gases throughout the planet, leading to a relatively uniform concentration of these gases across the globe. Therefore, CO2e emitted into the atmosphere within the analysis area would not stay confined to the analysis area and thus direct impacts to climate at the local scale would not be expected from the proposed action. Please see the analysis area in the EA for further clarification of the impact zone for the proposed action.
		Secondary Impacts. A "secondary impact" is defined as a "further impact to the human environment that may be stimulated or induced by or otherwise result from a direct impact of the action.24 The Draft EA describes secondary impacts of GHG emissions as: GHG emissions contribute to changes in atmospheric radiative forcing,	Thank you for your comment. The Commenter erroneously suggests the EA provides just three sentences describing secondary impacts from GHG emissions associated with the proposed action. The

		resulting in climate change impacts. GHGs act to contain solar energy loss by trapping longer wave radiation emitted from the Earth's surface and act as a positive radiative forcing component (BLM 2021). The impacts of climate change throughout the Northern Great Plains of Montana include changes in flooding and drought, rising temperatures, and the spread of invasive species (BLM 2021). This three-sentence generic explanation of the "secondary" impacts of GHG emissions on the climate is woefully inadequate. The Draft EA's perfunctory recitation of well-known impacts of climate change taken from a U.S. Bureau of Land Management report does not constitute the "hard look" required by MEPA. Further, just below the language DEQ copies from the report, is another paragraph that begins to paint a more complete picture of climate change impacts occurring in Montana: Climate projections suggest temperatures will increase throughout the 21st century across the region under all emission scenarios. Temperature increases of 2°–4°F projected by 2050 for the Northern Great Plains under the lower scenario (RCP4.5) are expected to result in an increase in the occurrence of both drought and heat waves. Under a higher emissions pathway (RCP8.5), historically unprecedented warming is projected by the end of the 21st century. The warmest climate model projections indicate average temperatures may increase by over 10°F above the 21 hottest temperatures observed during the 20th century. Temperature increases hottest temperatures observed during the 20th century. Temperature increases are	information provided within the EA provides reference to an extensive report on the subject prepared by the United States Department of Interior's Bureau of Land Management (BLM 2021). As is appropriate, DEQ did not copy and paste the entirety of the BLM report into the EA because doing so would unnecessarily burden the reader and ultimately detract from the affected public and decision-makers understanding of information relevant to the proposed action. Instead, DEQ provided information summarizing the content of the report as it relates to secondary impacts from GHG emissions. By summarizing the relevant information and providing citation and reference to the entirety of the BLM report, DEQ believes the BLM report appropriately provided the public and decision-makers with clear access to further detail and greater understanding of the summarized information provided in the EA. This well-researched and scientifically sound BLM report constitutes reliable science on the subject and provides readers with a complete understanding of GHG

		projected for all seasons with the most warming indicated during summer. This warming is predicted to occur along with less snowpack and a mix of increases and reductions in average annual water availability.25	science and trends in Montana and the Western U.S. Subsequent to publishing of the EA, DEQ identified an updated version of the BLM report prepared in 2022. The EA has been updated to reference the 2022 version of the BLM report.
		While DEQ is understandably out of practice with respect to the appropriate scope of climate change impacts under MEPA, the federal government and judicial branch have spent the last two decades clarifying what is required under NEPA, and caselaw interpreting the sufficiency of climate analyses under NEPA can provide a useful first step in MEPA analysis where an agency lacks familiarity with basic principles of climate analysis26. Of course, NEPA is not underpinned by the same constitutional imprimatur as is MEPA, so Federal caselaw can at best set a floor for MEPA analysis, not a ceiling. Nonetheless, federal cases provide a useful baseline.27	Thank you for your comment. The Commenter references the National Environmental Policy Act (NEPA), NEPA case law, and applicable definitions. In contrast, the EA was completed pursuant to the requirements of Montana Environmental Policy Act (MEPA). While NEPA and MEPA have similar purpose and intent, implementation of required environmental review pursuant to each act is varied in many ways. For example, and as the Commenter points out, NEPA analyzes "direct, *indirect*, and cumulative impacts" while, in contrast, MEPA requires the analysis of "direct, *secondary*, and cumulative impacts." (emphasis added). For the purposes of NEPA, indirect impact means "effects caused by a proposed action that occur later in time or

			are farther removed in distance, but are still reasonably foreseeable, often including growth-inducing effects like changes in land use patterns or population density resulting from the project; essentially, secondary impacts that arise as a consequence of the primary action. For the purposes of MEPA, secondary impact means "a further impact to the human environment that may be stimulated or induced by or otherwise *result from a direct impact of the action*." (emphasis added). As noted in a separate response to comment (see Direct Impacts above), because CO2e emitted to the atmosphere within the analysis area would not stay confined to that area and impacts would be global in nature. Little to no direct impacts to climate would be realized at the local scale. As defined by MEPA, because secondary impacts constitute impacts that may be stimulated or induced by or otherwise result from a *direct impact* of the action, little to no secondary impacts would be expected because of the proposed project. (emphasis added).

		The world is experiencing a fast rise in temperature that is unprecedented in the geologic record, with the average global temperature increasing by 2.2°F in the last 120 years. Montana is heating faster than the global average and the rate of warming is increasing. Overwhelming scientific evidence and consensus shows that this warming is the direct result of greenhouse gas (GHG) emissions that trap heat from the sun in the atmosphere, primarily from carbon dioxide (CO2) released from human extraction and burning of fossil fuels such as coal, oil, and natural gas. See also 350 Mont. v. Haaland, 50 F.4th 1254, 1261–62 (9th Cir. 2022); Massachusetts v. EPA, 549 U.S. 497, 521–22,127 S. Ct. 1438, 1455–56 (2007). These emissions accumulate in the atmosphere and may persist for hundreds of years—causing atmospheric CO2 levels to increase from 280 parts per million (ppm) in pre-industrial times to above 424 ppm today. These emissions result in extreme weather events that are increasing in frequency and severity, including droughts, heatwaves, forest fires, and flooding. These extreme weather events will only be exacerbated as the atmospheric concentration of GHGs continues to rise. Projections indicate that under a business-as-usual emissions scenario, Montana will see almost ten additional degrees of warming by 2100 compared to temperatures in 2000. By 2050, Montana will have 11–30 additional days per year with temperatures exceeding 90 degrees and a similar loss of days below freezing. Montana has already seen (and will increasingly see) adverse impacts to its economy, including to recreation, agriculture, and tourism caused by a variety of factors including decreased snowpack and	Thank you for your comment. Comment noted.

		water levels in summer and fall, extreme spring flooding events, accelerating forest mortality, and increased drought, wildfire, water temperatures, and heat waves.28	
		We would also direct DEQ to the resources we include in Appendix A, which include references and web links to the most significant climate change studies and reports in Montana and worldwide. These are excellent starting points for DEQ staff to familiarize themselves with climate impacts in Montana in order to fully inform decision makers and the public of the consequences of its continued authorization of additional GHG emissions. As discussed below, when combined with impacts that are already occurring as a result of existing emissions, such effects are precisely the type of impacts required to be analyzed.	Thank you for your comment and for the additional resources.
		Cumulative Impacts. The Draft EA's cumulative impact analysis is both deficient and misleading. Despite the applicant's prediction of an emissions increase from the proposed project, DEQ re-did the math and indicated this project will result in a decrease in GHG emissions.30 Regardless of which math is correct, this "cumulative impact" only applies to the furnace which Par Montana seeks to upgrade. Nowhere in the Draft EA does DEQ disclose the extent of the Par Montana refinery's GHG emissions, which again amount to 719,769 metric tons of CO2e emissions per year; equivalent to 167,890 gasoline-powered passenger vehicles driven for one year.31	Thank you for your comment. DEQ's Air Quality Bureau employs air quality professionals, including scientists with expert knowledge of how GHGs and other pollutants are dispersed and interact in the atmosphere. When industrial GHGs are emitted into the atmosphere, they become well-mixed globally due to their long lifetimes in the atmosphere (i.e., tens of years for methane to thousands of years for carbon dioxide) and atmospheric mixing, primarily driven by differential heating and synoptic-scale weather patterns, which distribute the gases

			throughout the planet, leading to a relatively uniform concentration of these gases across the globe. These factors contribute to an overall increase of GHG concentrations in the global atmosphere, not local airsheds, causing the enhanced global greenhouse effect. Localized industrial source greenhouse gas emissions do not impact climate, public health, and associated impacts to the affected human environment on a local scale. Further, because GHGs are not considered air pollutants with direct effects to public health and the environment, there are no associated director secondary air quality standards set to protect public health or the environment at the local scale. The existing GHG emissions attributable to Par are already accounted for in the cumulative impacts analysis.
		Cumulative Impacts. Instead of conducting a thorough cumulative impacts analysis that discloses and analyzes the significant sources of GHG emissions in this area as well as the associated climate impacts, the Draft EA provides unhelpful calculations to demonstrate that this furnace upgrade may contribute a miniscule amount of Montana's annual CO2e emissions.32 In the end, the Draft EA simply states the obvious, "GHG emissions that would be emitted as a result of the proposed	Thank you for your comment. Please see Section 24, Cumulative Impacts. DEQ provides a hard look with calculations so that a reader can understand the amount of change to the human environment that would occur because of the proposed action. The existing GHG

		activities would add to GHG emissions from other sources.33 This is not the hard look that MEPA requires, nor does it constitute an appropriate cumulative impacts analysis.34	emissions attributable to Par are already accounted for in the cumulative impacts analysis.
		The limited scope of the furnace upgrade analysis fails entirely to address the refinery's broader contribution to GHG emissions within the Billings/Laurel/Lockwood area. A legitimate cumulative impact analysis is critical for accurately assessing the project's role, particularly in the context of climate change, given the area's high concentration of refineries and other major sources of GHG emissions.35 This analysis must include an examination of the project within the context of existing sources' cumulative emissions, a step DEQ has skipped.36 Furthermore, the EA's comparison of project emissions to Montana's total emissions is insufficient and provides little meaningful information about the refinery's actual environmental impact.37 A comprehensive assessment of each project's emissions, however small they may seem in isolation, is essential to understanding and addressing the cumulative impact of fossil fuel development. A comprehensive GHG analysis in the MEPA review is not merely a procedural formality, but a crucial component in understanding the true environmental cost of the permit.	Thank you for your comment. GHGs are not currently regulated in Montana nor the United States in the Clean Air Act. To this point, GHGs are not considered air pollutants with direct effects to public health and the environment; therefore, no associated direct or secondary air quality standards have been set to protect public health or the environment, including climate, at the local or national scale. By comparison, there are National Ambient Air Quality Standards (NAAQS) for pollutants like ozone, sulfur dioxide, nitrogen dioxide, carbon monoxide, lead, and particulate matter that do have a localized impact on human health. The impact of GHG emissions is their impact on the earth's temperature by increasing GHG in the atmosphere, which in turn traps a larger amount of longwave radiation in the earth's atmosphere. This greenhouse effect from GHGs is a global phenomenon and not a localized impact that is

			comparable to the localized impacts of pollutants for which there are NAAQS.
		DEQ's environmental review must utilize established and scientifically grounded tools, such as the Social Cost of Greenhouse Gases ("SC-GHG"), to fully account for the project's climate impacts. The SC-GHG, a metric that quantifies the economic damages caused by each additional ton of GHGs emitted, provides a crucial framework for agencies to assess the long-term costs of their decisions.40 Ignoring this widely accepted tool undermines the core purpose of MEPA to inform the public and decision-makers about the environmental impacts of proposed Projects.41	Thank you for your comment. The use of CO_2e allows different types of GHGs to be easily compared in terms of their total global warming impact. CO_2e is a recognized unit to quantify a project's greenhouse gas assessment by the scientific community. DEQ declines to conduct its Greenhouse Gas Assessment through the lens of Social Cost of Greenhouse Gases (SC-GHG), which would have added an economic or dollar figure on top of CO_2e. SC-GHG compares the costs and benefits of the project under several assumptions like a discount rate for future damages related to GHG emissions. EPA, Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances, November 2023. DEQ finds that SC-GHG's evaluation of one impact in such economic terms would be inconsistent with the remainder of the EA, which does not evaluate impacts through quantitative economic measures.

			Instead, the EA generally discusses the project's benefits alongside its environmental impacts. Besides maintaining consistency in methodology within the EA, declining to adopt SC-GHG is warranted because MEPA does not require the precise quantitative cost-benefit analysis contemplated by SC-GHG. State ex rel. Montana Wilderness Ass'n v. Board of Natural Resources & Conservation, 200 Mont. 11, 33, 648 P.2d 734, 746 (1982); Belk v. Mont. Dep't of Envtl. Quality, 2022 MT 38, ¶ 29, 408 Mont.1, 504 P.3d 1090 (MEPA "require[s] assessments of impacts on human populations—including health, agriculture, tax bases, and culture—but they do not require quantitative economic forecasts.").
		Furthermore, the environmental review must consider the full lifecycle emissions associated with the Par Montana refinery, including not only direct emissions from the facility itself but also indirect or downstream emissions from the extraction, transportation, and consumption of refined petroleum products.42 Failing to account for these downstream emissions, which are reasonably foreseeable consequences of the refinery's operation, creates a significant vulnerability in the DEQ's environmental analysis. Numerous federal court decisions, including those	This EA was completed under the requirements of MEPA. As the commenter pointed out, NEPA has "indirect impacts" which MEPA does not have. In NEPA and in the cases referenced in the comment are dealing with impacts that are "reasonably foreseeable" under the Indirect and Cumulative impact

		related to pipeline permitting, coal transport 43 mine plan modifications,44 and oil and gas development,45 have consistently emphasized the necessity of analyzing the full scope of emissions. Nothing in state caselaw interpreting MEPA (including Bitterrooters for Planning, Inc. v. DEQ, 2017 MT 222, 388 Mont. 453, 401 P.3d 712) supports a contrary view that agencies may analyze only the direct emissions related to a proposed activity. This approach aligns with the evolving understanding of climate science and federal jurisprudence, requiring agencies to consider the complete environmental footprint of their decisions. DEQ's efforts to narrowly circumscribe the scope of its GHG analysis and reduce it to a mere checkbox exercise are concerning. This restrictive approach contravenes the Court's directives in Held and MEIC as well as established federal case law under NEPA and, more fundamentally, DEQ's constitutional obligations. This deficiency is particularly acute given the presence of existing cumulative sources of GHG emissions, such as refineries, that have not yet been subject to a comprehensive climate analysis. Therefore, the DEQ must ensure that the environmental review includes a comprehensive assessment of lifecycle emissions, providing a complete and accurate picture of the project's contribution to GHG concentrations and climate change.	definitions in NEPA. Please see 75-1-220(4), MCA, for the definition of Cumulative impacts and ARM 17.4.603(18) for the definition of Secondary impact under MEPA. Through this permit review, DEQ has no permitting authority over upstream or downstream activities related to products refined at the facility. Instead, DEQ has authority over the air quality permit for emissions that occur under this proposed action. Accordingly, pursuant to Bitterrooters for Planning, Inc. v. DEQ, 2017 MT 222, DEQ is not required to evaluate impacts emanating from activities beyond its permitting authority in Montana. Accord MEIC v. DEQ, 2025 MT 3, PP 48-62.
		Alternatives. An "alternative" includes "design parameters, mitigation, or controls other than those incorporated into a proposed action by an applicant or by an agency prior to preparation of an EA or draft EIS."46 The EA should also consider a range of alternatives, including a reasonable alternative for managing the decline of GHG emissions. This could involve exploring	Thank you for your comment. The CO_2e potentially emitted from this proposed project have been reported as CO_2e as specified in Section 24 of the EA. Under MEPA, DEQ has completed the EA

		options for reducing the carbon footprint of the refinery's operations, such as fuel switching or carbon capture, utilization, and storage.47 The EA should also analyze the potential economic and social impacts of these alternatives, ensuring that a full understanding of the environmental, economic, and social implications of the permit informs the DEQ's decision-making process. A thorough and detailed analysis of GHG emissions and their impacts is essential for the DEQ to fulfill its responsibility to protect Montanan's constitutional rights.	analyzing the impacts from the Proposed Action and No Action Alternatives. The measures to mitigate the CO_2e impacts from this Proposed Project would be the following: 1) the No Action Alternative, which could not be selected by DEQ if the applicant were to submit a substantive, administrative, and technically complete application. 2) The Proposed Action, which has the potential to reduce CO_2e by 1,482 metric tons per year into the atmosphere.
		It is clear that DEQ's broad authority under the Montana Clean Air Act gives the agency the ability to regulate air pollution and to establish emission limits "from any source necessary to prevent, abate, or control air pollution.[48] This clear substantive statutory authority, as emphasized in MEIC v. Montana DEQ, only bolsters the responsibility of DEQ to accurately and thoroughly assess the GHG emissions and climate impacts of its permitting and other actions under MEPA.	Thank you for your comment. DEQ has no authority to regulate GHGs under either the Federal Clean Air Act or the Clean Air Act of Montana.
		Given the substantial GHG emissions and air pollution associated with the Par Montana facility, coupled with the existing concentration of refineries and associated emission sources within the Billings, Laurel, and Lockwood region, a programmatic environmental review is warranted to comprehensively analyze the cumulative climate and public health impacts associated with the DEQ's air permit authorizations. This area's high density of industrial facilities presents a significant potential for synergistic and cumulative	Thank you for your comment. Please see the sections of the EA titled "Need for Further Analysis and Significance of Potential Impacts" and "Conclusions and Findings".

		environmental and public health impacts, necessitating the rigorous analysis and heightened public scrutiny afforded by a programmatic environmental impact statement ("EIS"). Specifically, the Par Montana refinery ranks as the fifth-largest source of GHG emissions in Montana, and, significantly, five of the state's top six GHG emission sources are concentrated within the Billings/Laurel/Lockwood area, collectively responsible for over 4.2 million metric tons of CO2e emissions annually. A programmatic EIS would enable a comprehensive evaluation of the aggregate impacts of these facilities on air quality, public health, and the regional climate, including a thorough consideration of alternative scenarios and potential mitigation measures. This comprehensive analysis is essential to ensure a more informed and transparent decision-making process, consistent with DEQ's constitutional mandate to protect and maintain a clean and healthful environment for Montana citizens. Furthermore, in light of the ongoing climate crisis and the legal precedent established by Held and MEIC, a programmatic approach is not only prudent but is essential to fulfill DEQ's legal obligation to conduct a thorough and comprehensive "hard look" at the environmental consequences of its permitting decisions. This "hard look" must encompass the full lifecycle emissions of these facilities, including upstream and downstream impacts, and incorporate a robust consideration of the SC-GHG, thereby ensuring that the cumulative burden of industrial emissions within the region is fully understood, accurately quantified, and appropriately accounted for in DEQ's decision-making process.	

G. Additional Information

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

II. Applicable Rules and Regulations

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

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

1. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

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

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by DEQ, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   Par shall comply with the requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from DEQ upon request.

4. ARM 17.8.110 Malfunctions. (2) The 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 of 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 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
2. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
3. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
4. ARM 17.8.213 Ambient Air Quality Standard for Ozone
5. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
6. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
7. ARM 17.8.221 Ambient Air Quality Standard for Visibility
8. ARM 17.8.222 Ambient Air Quality Standard for Lead
9. ARM 17.8.223 Ambient Air Quality Standard for PM10
10. ARM 17.8.230 Fluoride in Forage

Par must maintain compliance with the applicable ambient air quality standards.

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 into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. This rule requires an opacity limit 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, Par 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 17.8.324(3) Hydrocarbon Emissions--Petroleum Products. 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 or is a pressure tank as described in (1) of this rule.

5. 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. Par is considered an NSPS affected facility under 40 CFR Part 60 and is subject to the requirements of the following Subparts.

a. Subpart A, General Provisions apply to all equipment or facilities subject to an NSPS Subpart as listed below.

b. Subpart J, Standards of Performance for Petroleum Refineries. This Subpart applies to facilities that are constructed or modified after June 11, 1973; therefore, new and modified fuel gas combustion devices will be subject to the provisions of Subpart J.

c. Subpart Ja, Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007, shall apply to Boiler B-8 Temp and B-8 and any other affected equipment.

d. Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels. This Subpart shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984. These requirements shall be as specified in 40 CFR Part 60.110b through 60.117b.

e. Subpart UU, Standards of Performance for Asphalt Processing and Asphalt Roofing Manufacture. This Subpart applies to each asphalt storage tank that commences construction or modification after November 18, 1980. Tank #55 will be subject to these requirements and will be required to meet 0% opacity limit, except for one 15-minute period each 24-hour period.

f. Subpart GGG, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for which Construction, Reconstruction, or Modification Commenced After January 4, 1983, and on or Before November 7, 2006.

   Par will comply with Subpart GGG, as applicable, for the Fluid Coker project, Hydrofiner #1 (HF-1), the Hydrofiner #3 (HF-3), and the PMA project.

g. Subpart GGGa, Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006. Par will comply with Subpart GGGa, as applicable, for C-310 and any other affected sources.

h. Subpart QQQ, Standards of Performance for VOC Emissions from Petroleum Refinery Wastewater Systems. This rule pertains to facilities that are constructed or modified after May 4, 1987. The affected facilities include an individual drain system, an oil-water separator, and an aggregate facility (drain system included with downstream sewer lines and oil-water separators).

i. Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Compression Engines (CI ICE). Owners and operators of stationary CI ICE that commence construction after July 11, 2005, where the stationary CI ICE are manufactured after April 1, 2006, and are not fire pump engines or are manufactured as a certified National Fire Protection Association (NFPA) fire pump engine after July 1, 2006, and owners and operators of stationary CI ICE that modify or reconstruct their stationary CI ICE after July 11, 2005, are subject to this subpart. Emergency Engines SE7-SE14 are all subject to this subpart.

6. <u>ARM 17.8.341 Standards of Performance for Hazardous Air Pollutants</u>. The source shall comply with the standards and provisions of 40 CFR Part 61, as appropriate.

   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. The source shall comply with the standards and provisions of 40 CFR 61, Subpart FF, as appropriate.

7. <u>ARM 17.8.342 Emission Standards for Hazardous Air Pollutants</u>. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as appropriate.

   a. Subpart A, General Provisions applies to all NESHAP source categories subject to a Subpart as listed below.

   b. Subpart CC, National Emission Standards for Hazardous Air Pollutants for Petroleum Refineries (Refinery MACT I). This regulation applies to petroleum refining process units and to related emission points as specified in this Subpart.

   c. 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). This regulation applies to petroleum refining process units and to related emission points as specified in this Subpart.

   d. Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (RICE). An owner or operator of a stationary reciprocating internal combustion engine (RICE) at a major or area source of HAP emissions is subject to this rule except if the stationary RICE is being tested at a stationary RICE test cell/stand. An area source of HAP emissions is a source that is not a major source. All of the RICE are affected units under this subpart because the facility is a major source of HAP emissions.

e. Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. This regulation applies because Par is a major source of HAPs that operates affected units.

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

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to DEQ. Par submitted the appropriate fee for the current permit action.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to DEQ by each source of air contaminants holding an air quality permit (excluding an open-burning permit) issued by DEQ; and the annual air quality operation fee is based on the actual or estimated actual amount of air contaminants 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. DEQ may insert into any final permit issued after the effective date of these rules, such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that prorate the required fee amount.

E. 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 Potential to Emit (PTE) greater than 25 tons per year of any pollutant. Par has a PTE greater than 25 tons per year of PM, particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), NO_X, CO, VOC, and SO_2; 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. <u>ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements</u>. (1) This rule requires that a permit application be submitted prior to installation, modification, or use of a source. Par submitted the required permit application for the current permit 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. Par submitted an affidavit of publication of public notice for the *December 12, 2024*, issue of *The Billings Gazette*, a newspaper of general circulation in the town of Billings, MT.

6. <u>ARM 17.8.749 Conditions for Issuance or Denial of Permit</u>. This rule requires that the permits issued by DEQ must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. <u>ARM 17.8.752 Emission Control Requirements</u>. 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. <u>ARM 17.8.755 Inspection of Permit</u>. This rule requires that air quality permits shall be made available for inspection by DEQ at the location of the source.

9. <u>ARM 17.8.756 Compliance with Other Requirements</u>. This rule states that nothing in the permit shall be construed as relieving Par 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. <u>ARM 17.8.759 Review of Permit Applications</u>. This rule describes DEQ's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. <u>ARM 17.8.762 Duration of Permit</u>. 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. <u>ARM 17.8.763 Revocation of Permit</u>. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of

Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of Intent to Transfer, including the names of the transferor and the transferee, is sent to DEQ.

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

1. ARM 17.8.801 Definitions. Par's existing Billings petroleum refinery (including both the refinery and the bulk terminal) is defined as a "major stationary source" because it is a listed source with the PTE more than 100 TPY of several pollutants (SO_2, CO, NO_X, and VOCs).

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemption. 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 chapter would otherwise allow. Par's existing petroleum refinery in Billings is defined as a "major stationary source" because it is a listed source with a PTE more than 100 tons per year of several pollutants (PM, SO2, NOx, CO, and VOCs). This action did not exceed the significant emissions rates associated with a major modification and is therefore, not subject to PSD.

G. ARM 17.8, Subchapter 12, Operating Permit Program Applicability, including, but not limited to:

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 Hazardous Air Pollutant (HAP), PTE > 25 TPY of a combination of all HAPs, or a lesser quantity as DEQ may establish by rule; or

c. PTE > 70 TPY of PM_{10} in a serious PM_{10} 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 #1564-38 for Par, 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_{10} nonattainment area.

   d. This facility is subject to NSPS requirements (see section II.B.5 of this analysis).

   e. This facility is subject to current NESHAP requirements (see section II.B.7 of this analysis).

   f. This source is not a Title IV affected source,

   g. This source is not a solid waste combustion unit.

   h. This source is not an EPA designated Title V source.

   Based on these facts, DEQ determined that Par is a major source of emissions as defined under Title V.

III. BACT Determination

A BACT analysis and determination is required for each new or modified source. Par shall install on the new or modified source the maximum air pollution control capability, which is technically practicable and economically feasible, except that BACT shall be utilized.

A top-down BACT analysis was submitted by Par in permit application #1564-38, addressing available methods of controlling for NO_X, CO, and VOC emissions from the Crude Furnace (F-1).
DEQ reviewed these methods, as well as previous BACT determinations for the control of SO_2, $PM/PM_{10}/PM_{2.5}$. The following control options have been reviewed by DEQ in order to make the following BACT determination.

Step 1 – Identify Control Options

Good Combustion Practices/Refinery Fuel Gas - Good combustion practices and the use of refinery fuel gas (RFG) are associated with Par's combustion optimization system and are the baseline emission control for NO_X, CO, and VOCs as well as SO_2, $PM/PM_{10}/PM_{2.5}$.

Flue Gas Recirculation - FGR is an intrinsic flame-quenching technique that involves recirculating a portion of the flue gas from the economizers or the air heater outlet and returning it to the furnace through the burner or windbox.
The primary effect of FGR is to reduce the peak flame temperature through absorption of the combustion heat by relatively cooler flue gas. The lower flame temperature can reduce the production of NO_X emissions. FGR also serves to reduce the oxygen concentration in the combustion zone, starving the NO_X forming reaction of the oxygen needed.

Ultra Low NO_X Burners - ULNBs are also intrinsic to combustion operations and are often used in conjunction with FGR. ULNBs integrate staged combustion into the burner creating a fuel-rich primary combustion zone. Fuel NO_X formation is decreased by the reducing conditions in the primary combustion zone. Thermal NO_X is limited due to the lower flame temperature caused by the lower oxygen concentration. The secondary combustion zone is a fuel-lean zone where combustion is completed. ULNB may result in increased CO and hydrocarbon emissions, decreased boiler efficiency and increased fuel costs.

Selective Non-catalytic Reduction – SNCR is a post-combustion emissions control technology for reducing NO_X by injecting an ammonia (NH_3)-type reactant into the combustion device at a properly determined location. This technology is often used for mitigating NO_X emissions since it requires a relatively low capital expense for installation, albeit with relatively higher operating costs. The conventional SNCR process occurs within the combustion unit, which acts as the combustion chamber. The reactions typically take place between 1,550°F and 1,950°F, because a catalyst is not used to drive the reaction. The efficiency of the conversion process diminishes quickly when operated outside the optimum temperature band and additional ammonia slip or excess NO_X emissions may result. The median reductions for urea based SNCR systems in various industry source categories range from 25 to 60 percent.
Selective Catalytic Reduction – SCR is also a post-combustion gas treatment technique for reduction of nitric oxide (NO) and nitrogen oxide (NO2) in an exhaust stream to molecular nitrogen, water, and oxygen. NH_3 or urea is used as the reducing agent. SCR is typically implemented on stationary source combustion units requiring a higher level of NO_X reduction than may be achievable by SNCR or combustion controls. In practice, commercial coal-, oil-, and natural gas–fired SCR systems are often designed to meet control targets of over 90 percent. Actual control efficiency rates may vary based on configuration and unit type.

Step 2 – Eliminate Technically Infeasible Options

Good Combustion Practices/Refinery Fuel Gas – Good combustion practices and the use of RFG are technically feasible for control of NO_X, CO, VOC, SO_2, and $PM/PM_{10}/PM_{2.5}$.

FGR - Because of the intrinsic nature of FGR, the technology is generally installed in new units that incorporate specific characteristics into the design and is typically used in boilers rather than Crude/Atmospheric Furnaces. To achieve NO_X, CO, and VOC reduction, flue gas off the convection section would be ducted back into the burner requiring additional space and infrastructure. Along with additional infrastructure, operation of the FGR requires oxygen (O_2) controls to be 1.5 – 2% excess O_2. Due to the configuration of the crude furnace, this design is technically infeasible.

UNLB - ULNBs achieve a lower outlet NO_X concentration by staging combustion with the goal of reducing peak flame temperature; this has the impact of driving a longer flame length for natural draft burners as combustion is delayed. A longer flame pattern for F-1 can result in excessive tube metal temperatures at design firing rates, which can ultimately result in tube rupture with associated safety, environmental, and economic consequences. This is unavoidable without major structural changes to the heater.

The primary challenge associated with retrofitting the existing F-1 Furnace with ULNB designs is the horizontal burner configuration and relatively short radiant firebox spacing. One refinery furnace (F-103) at the Marathon Anacortes Refinery was retrofitted with ULNBs following a 2010 BART determination by the Washington Department of Ecology. However, that furnace had a burner configuration and firebox design that was amenable to the change. Multiple other furnaces/heaters at the Anacortes site were evaluated for ULNB retrofit in the 2017 BART analysis but encountered similar difficulties with respect to the dangers of ULNBs causing excessive tube metal temperatures and potential tube rupture. ULNBs on those additional furnaces/heaters were determined to be infeasible with respect to technical concerns and cost. Operating experience and conventional guidance for ULNB installations would indicate that retrofitting the existing F-1 burners with a natural draft ULNB of the same quantity and heat capacity is technically infeasible.

SNCR - While SNCR is commonly considered on other fuel combustion devices, such as boilers, it is not technically feasible on furnaces. Furnace operation temperatures (600-700 ˚F) are far below the temperatures needed for SNCR to effectively operate (1,550 to 1,950˚F) per the EPA Cost Control Manual (Seventh Edition), Section 4 – NO_X Controls, Chapter 1 - SNCR (updated on June 12, 2019). Therefore, SNCR is eliminated based on technical infeasibility.

SCR – SCR is technically feasible for control of NO_X

Step 3 – Rank Remaining Options by Control Effectiveness

Available control technology options deemed technically feasible from Step 2 are ranked in order of pollutant removal effectiveness. The control option that results in the highest pollutant removal value is considered the "top" control alternative. The remaining technologies are SCR and the base case of good combustion practices.

Step 4 – Evaluate Most Cost-Effective Controls and Document Results

Good Combustion Practices/Refinery Fuel Gas - Good combustion practices and the use of RFG are currently required for the F-1 furnace and have no negative energy, environmental, or economic impacts.

SCR - Although there are no prohibitive environmental issues that would preclude the use of an SCR system, there are some areas of concern. SCR presents several potential adverse environmental impacts. Unreacted NH_3 in the flue gas (NH_3 slip) and the products of secondary reactions between NH_3 and other species present in the flue gas will be emitted to the atmosphere. NH_3 slip causes the formation of additional condensable particulate matter such as ammonium sulfate, $(NH_4)2SO_4$. The $(NH_4)2SO_4$ can corrode downstream exhaust handling equipment, as well as increase the opacity or visibility of the exhaust plume. In most cases, designing for a low NH_3 slip minimizes these adverse effects.

An SCR has a small energy penalty on the facility, primarily due to the energy required to vaporize aqueous NH_3. Costs for this energy expenditure are included below. Alone, these energy impacts would not eliminate SCR as a method to control NO_X.

The economic analysis for this unit is based on calculations performed in 2019 Regional Haze analysis for installation of SCR in the F-1/F-401 exhaust (as they share the same stack and have a total maximum heat input rate of 280 MMBtu/hr) using the still current EPA Control Cost Spreadsheet for SCR. The 2019 calculations were based on the default retrofit complexity of "1" and the default annual interest rate of 5.5% (both of which understate the actual costs, as retrofitting units in a refinery setting is never typical and the current prime rate is approximately 8.0%). The overall costs were updated to reflect the mid-2024 Chemical Engineering Plant Cost Index. Installing SCR to the F-1/F-401 stack and applying that cost to the increase in F-1 emissions associated with this action would yield a cost of $159,227/ton. Based on this information, SCR is not economically feasible and is eliminated from further evaluation.

Step 5 – Select BACT

Based on this analysis, Par determined, and DEQ concurs, that Good Combustion Practices and the use of RFG constitute BACT for the control of NO_X, CO, VOC, SO_2, and $PM/PM_{10}/PM_{2.5}$. As previously discussed, good combustion practices are associated with Par's combustion optimization system. Par is proposing a maximum hourly NO_X BACT emission limit of 58.0 lb/hr and 23.7 lb/hr of CO.

The NO_X limit is derived from the same methodology used for the F-551 permit application and approved by DEQ for a very similar furnace modification project as that currently proposed for the F-1 furnace. The limit is calculated below:

Average NO_X stack test result from August 2023:	38.67 lbs/hr
Average F-1 Firing Rate during stack test:	176.06 MMBtu/hr
Maximum F-1 Firing Rate:	240 MMBtu/hr
Prorated Emission Rate to Max Firing Rate:	$52.72\frac{lb}{hr} * \frac{240mmBtu/hr}{176.06\,mmBtu/hr}$
Contingency Factor:	10%
Proposed Maximum Hourly NO_X Emission Rate:	58.0 lbs/hr.

The F-1 project focuses on optimizing combustion efficiency which will minimize CO emissions through those practices. To quantify those emissions in the current annual emissions inventory for F-1, the CO emission factor for natural gas consumption in a wall-fired boiler (greater than 100 MMBtu/hr firing rate) as found in AP-42, Table 1.4-1: 84 lb/MMscf of gas burned. Par proposes to use that factor as a foundation for the F-1 CO BACT limit. As stated in Table 1.4-1, Footnote a: "Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf ... The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value." The F-1 Furnace burns RFG, not natural gas. That emission factor can be converted using the average RFG heating value used in the baseline for the MAQP application of 1205 Btu/scf. The resulting emission factor is 99 lb/MMscf. Par is requesting a 20% contingency on that factor. Converting the emission factor to a BACT limit/condition in pounds per hour results in a CO limit of 23.7 lb/hr using good combustion practices.

With the NO_X hourly limitation, CO and VOCs would be controlled through use of RFG as a fuel source along with complete combustion of fuel through good combustion practices.

Previous BACT determinations for similar sources have identified combustion of RFG as BACT because of the limited amounts of SO_2, $PM/PM_{10}/PM_{2.5}$. Par currently utilizes refinery fuel gas as BACT for other furnaces at the refinery and would continue to use refinery fuel gas as a fuel source for F-1.

The control options selected have controls and control costs comparable to other similar permitted sources and are capable of achieving the appropriate emission standards.

Based on the above top-down BACT analysis, DEQ determined that Good Combustion Practices constitutes BACT for NO_X, CO, and VOC emissions from the modified F-1 furnace. Previous BACT determinations of RFG for control of SO_2, $PM/PM_{10}/PM_{2.5}$ combined with good combustion practices remain in place as BACT for the control of SO_2, $PM/PM_{10}/PM_{2.5}$.

IV. Emission Inventory

CONTROLLED	**tons/year**						
Emission Source	**PM**	**PM_{10}**	**$PM_{2.5}$**	**NO_X**	**CO**	**VOC**	**SO_X**
Crude Furnace (F-1)	0.20	0.20	0.20	5.73	2.23	0.28	0.12
Total Emissions	**0.20**	**0.20**	**0.20**	**5.73**	**2.23**	**0.28**	**0.12**

Note - the emissions increase for the current permit action are an increase from 2-year baseline emissions data taken from September 2019 through August 2020.

Calculations:

Crude Furnace (F-1)		
Operational Capacity Increase = 53.17 mmscf/yr	53.17	**mmscf/yr**
Pounds per ton	0.0005	**ton/lb**
Increase in Hours of Operation = 336 hr/yr	336	**hr/yr**
PM Emissions:		
Emission Factor = 0.20 ton/yr	0.20	**ton/yr**
PM-10 Emissions:		
Emission Factor = 7.6 lb/mmscf	7.6	**lb/mmscf**
Calculation: ((7.6 lb/mmscf) * (53.17 mmscf/yr) * (0.0005 ton/lb)) = 0.20 ton/yr	0.20	**ton/yr**
PM2.5 Emissions		
Emission Factor = 7.6 lb/mmscf	7.6	**lb/mmscf**

Calculation: ((7.6 lb/mmscf) * (53.17 mmscf/yr) * (0.0005 ton/lb)) = 0.20 ton/yr	0.20	**ton/yr**
NOx Emissions:		
Emission Factor = 215.6 lb/mmscf	215.6	**lb/mmscf**
Calculation: ((215.6 lb/mmscf) * (53.17 mmscf/yr) * (0.0005 ton/lb)) = 5.73 ton/yr	5.73	**ton/yr**
CO Emissions:		
Emission Factor = 84.0 lb/mmscf	84	**lb/mmscf**
Calculation: ((84.0 lb/mmscf) * (53.17 mmscf/yr) * (0.0005 ton/lb)) = 2.23 ton/yr	2.23	**ton/yr**
SO_X Emissions:		
Emission Factor = 4.5 lb/mmscf	4.5	**lb/mmscf**
Calculation: ((4.5 lb/mmscf) * (53.17 mmscf/yr) * (0.0005 ton/lb)) = 0.12 ton/yr	0.12	**ton/yr**
VOC Emissions:		
Emission Factor = 10.7 lb/mmscf	10.7	**lb/mmscf**
Calculation: ((10.7 lb/mmscf) * (53.17 mmscf/yr) * (0.0005 ton/lb)) = 0.28 ton/yr	0.28	**ton/yr**

V. Existing Air Quality

Par is located at 700 Par Montana Road, Billings, Montana in the South ½ of Section 24 and the North ½ of Section 25, Township 1 North, Range 26 East in Yellowstone County. This area is considered attainment for all criteria pollutants. The Laurel SO_2 nonattainment area is nearby.

VI. Ambient Air Impact Analysis

DEQ determined, based on amount of allowable emission, that the impacts from this permitting action will be minor. DEQ believes it will not cause or contribute to a violation of any ambient air quality standard.

VII. Taking or Damaging Implication Analysis

As required by 2-10-105, MCA, DEQ conducted the following private property taking and damaging assessment and is included in the Environmental Assessment (EA).

VIII. Environmental Assessment

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

Montana Department of Environmental Quality

DRAFT ENVIRONMENTAL ASSESSMENT

Par Montana, LLC. – Billings Refinery

Air Quality Bureau

Air, Energy, and Mining Division

Table of Contents

Project Overview

COMPANY NAME:	Par Montana, LLC.
EA DATE:	January 29, 2025
SITE NAME:	Billings Refinery
MAQP#:	#1564-38
Application Received Date:	December 20, 2024

Location

T/S/R: Township 1 North, Section(s) 24 & 25, Range 26 East
County: Yellowstone
PROPERTY OWNERSHIP: FEDERAL STATE PRIVATE X

Compliance with the Montana Environmental Policy Act

Under the Montana Environmental Policy Act (MEPA), Montana agencies are required to prepare an environmental review for state actions that may have an impact on the human environment. The proposed action is considered to be a state action that may have an impact on the human environment and, therefore, the Department of Environmental Quality (DEQ) must prepare an environmental review. This Environmental Assessment (EA) will examine the proposed action and alternatives to the proposed action and disclose potential impacts that may result from the proposed and alternative actions. DEQ will determine the need for additional environmental review based on consideration of the criteria set forth in Administrative Rules of Montana (ARM) 17.4.608. DEQ may not withhold, deny, or impose conditions on the Permit based on the information contained in this EA (§ 75-1- 201(4), MCA).

Proposed Action

Par Montana, LLC. – Billings Refinery (Par) is proposing to upgrade the Crude Furnace (F-1) to improve thermal efficiency. The proposed upgrades include replacing the internal crude piping with uniform tubing, replacing the refinery fuel gas burners with new "in-kind" modern models, and refractory repairs as necessary. With the design upgrades, efficiency for the crude furnace will increase to approximately 87%, from the previous efficiency of 81%. This increase in efficiency will result in a reduction of approximately 18.7 million standard cubic feet of gas being used annually.

Purpose and Need

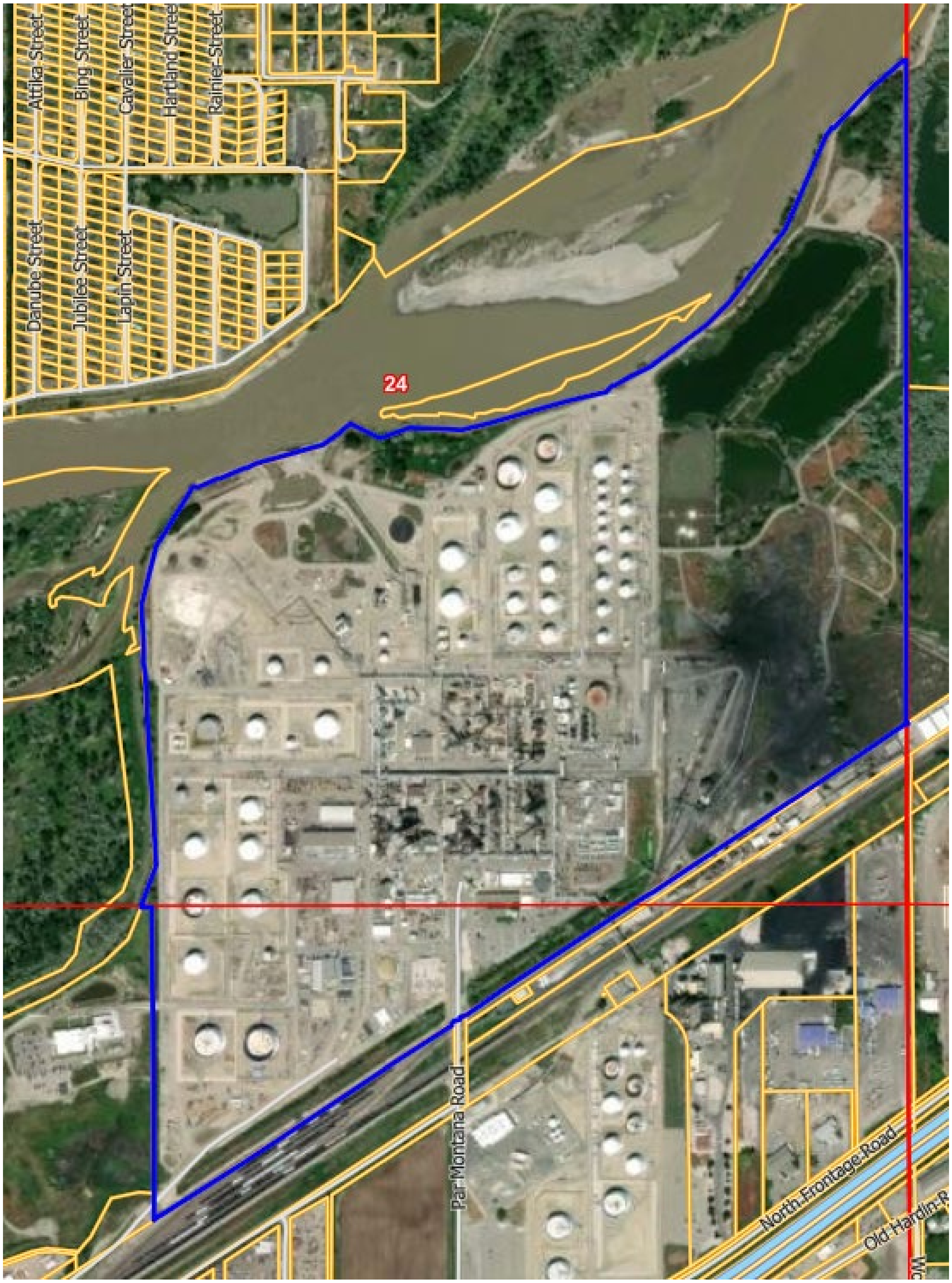
Under MEPA, Montana agencies are required to prepare an environmental review for state actions that may have an impact on the human environment. The Proposed Action is considered to be a state action that may have an impact on the human environment and, therefore, DEQ must prepare an environmental review. This EA will examine the proposed action and alternatives to the proposed action and disclose potential impacts that may result from the proposed and alternative actions. DEQ will determine the need for additional environmental review based on consideration of the criteria set forth in ARM 17.4.608.

TABLE 1: SUMMARY OF ACTIVITIES PROPOSED IN APPLICATION

Table 1. Summary of Proposed Activities in Application	
General Overview	The proposed action would increase the facilities thermal efficiency through uniform crude pipes with fined tubes attached to increase thermal absorption, new "in-kind" refinery fuel gas burners, and refractory repairs to decrease thermal dissipation through the facility structure.
Duration and Timing	Construction: The proposed project is anticipated to start construction in April 2026 and take approximately 2 months to complete.
Estimated Disturbance	No new disturbances are expected with the proposed project.
Equipment	Various types of heavy equipment to include cranes, dump trucks, front end loaders, and skid steers could be used for the proposed project.
Location	The location of the proposed project is within the property boundaries of the Par Montana refinery. See Figure 1 below.
Personnel on-site	Par currently employes approximately 320 people. No new permanent jobs will be created by the proposed project.
Location and Analysis Area	Section(s) 24 & 25, Township 1 North, Range 26 East
Air Quality	Impacts to air quality are expected to be minor and long-term.
Water Quality	No impact on water quality is expected.
Erosion Control and Sediment Transport	Existing company staff would oversee erosion control and sediment transport in the event of precipitation.
Solid Waste	Solid waste generated from the proposed project is expected and would be properly disposed of in local county landfills.
Cultural resources	The Applicant is required to comply with the applicable local, county, state, and federal requirements pertaining to cultural resources.
Aesthetics	The property is already in use as a petroleum refinery. No new structures are expected to be constructed.
Hazardous Substances	This project does not contribute any hazardous substances to the facility. The Applicant is required to comply with the applicable local, county, state, and federal requirements pertaining to hazardous substances.
Weed Control	The Applicant is required to comply with the applicable local, county, state, and federal requirements pertaining to weed control.
Reclamation Plans	DEQ is unaware of any reclamation plans for the refinery.

Cumulative Impact Considerations	
Past Actions	This is an existing site with multiple past actions that are not considered part of the current permit action.
Present Actions	Update the crude Furnace (F-1) to improve efficiency primarily through updating tube design within the furnace building and installing new "in-kind" natural gas-fired burners and repairing/replacing refractory material.
Related Future Actions	No future actions are foreseen as of the date of this EA for the site.

Figure 1. Par Montana, LLC. – Billings Refinery



EVALUATION OF AFFECTED ENVIRONMENT AND IMPACT BY RESOURCE:

The impact analysis will identify and evaluate whether the impacts are direct or secondary impacts to the physical environment and human population in the area to be affected by the proposed project. Direct impacts occur at the same time and place as the action that causes the impact. Secondary impacts are a further impact to the human environment that may be stimulated, or induced by, or otherwise result from a direct impact of the action (ARM 17.4.603(18)). Where impacts would occur, the impacts will be described.

Cumulative impacts are the collective impacts on the human environment within the borders of Montana that could result from the Proposed Action when considered in conjunction with other past and present actions related to the Proposed Action by location and generic type. Related future impacts must also be considered when these actions are under concurrent consideration by any state agency through pre-impact statement studies, separate impact statement evaluation, or permit processing procedures. The activities identified in Table 1 were analyzed as part of the cumulative impacts assessment for each resource.

The duration is quantified as follows:

- Construction Impacts (short-term): These are impacts to the environment during the construction period. When analyzing duration, please include a specific range of time.

- Operation Impacts (long-term): These are impacts to the environment during the operational period. When analyzing duration, please include a specific range of time.

The intensity of the impacts is measured using the following:

- No impact: There would be no change from current conditions.

- Negligible: An adverse or beneficial effect would occur but would be at the lowest levels of detection.

- Minor: The effect would be noticeable but would be relatively small and would not affect the function or integrity of the resource.

- Moderate: The effect would be easily identifiable and would change the function or integrity of the resource.

- Major: The effect would alter the resource

1. Geology and Soil Quality, Stability, and Moisture

The affected area is an already developed petroleum refinery. The project area consists of mainly asphalt cement, crude oil piping infrastructure, and crude oil refining infrastructure with associated equipment.

The Yellowstone alluvial valley in the West Billings area is underlain by a relatively shallow, thin, unconfined to semi-confined aquifer system. Stratigraphic components of this system include the shale base underlying the aquifer, terrace alluvial gravel aquifers, and a fine-grained sediment cap. In the project area, the Yellowstone River has cut its valley 200–300 feet into late Cretaceous shale formations of the Colorado Group. The Colorado Group is exposed south of the valley and underlies the alluvial deposits of the valley (Lopez, 2000). The approximately 2,000-foot-thick shale sequence is typically a poor source of ground water, with low yields and poor water quality. The shale bedrock surface has been scoured by past erosion of the Yellowstone River. Deeper channel cuts and terrace cut benches are evident in the bedrock topography (plate 1). The shale at the base of the aquifer is typically weathered to a dense clay that is relatively impermeable and does not provide significant recharge to or discharge from the alluvial aquifer system. The valley is bounded on the north by a 300-foot-high cliff formed by the Eagle Sandstone and the Telegraph Creek Formation. These formations are Cretaceous, interbedded sandstone and shale that dip gently northward and are not present under the valley in the project area (Lopez, 2000).

Direct Impacts:
There will be no direct construction or operational impacts to geology, soil quality, stability, or moisture as a result of the project. The current site is an already developed petroleum refinery with no new ground disturbances. All of the proposed actions will take place inside crude furnace (F-1) facility

Secondary Impacts:
There will be no secondary construction or operational impacts to geology or soil quality, stability, and moisture. The current site is an already developed petroleum refinery with no new ground disturbances. All of the proposed actions will take place inside the F-1 facility.

Cumulative Impacts:
There will be no cumulative impacts to geology or soil quality, stability, and moisture. The current site is an already developed petroleum refinery with no new ground disturbances. All of the proposed actions will take place inside the F-1 facility.

2. Water Quality, Quantity, and Distribution

This project would not impact any surface or groundwater in the area. The proposed project is located within the existing property boundary of the refinery and will be confined to the F-1 facility.

Direct Impacts:
There will be no direct construction or operational impacts to water quality, quantity, or distribution. The current site is an already developed petroleum refinery.
All of the proposed actions will take place inside the property boundary, within crude furnace (F-1) facility.

Secondary Impacts:
There will be no secondary construction or operational impacts to water quality, quantity, or distribution. The current site is an already developed petroleum refinery where all of the proposed actions will take place inside the crude furnace (F-1) facility.

Cumulative Impacts:
There will be no cumulative construction or operational impacts to water quality, quantity, or distribution. The current site is an already developed petroleum refinery where all of the proposed actions will take place inside the crude furnace (F-1) facility.

3. Air Quality

Air quality in the affected area is classified as unclassifiable/attainment of the National Ambient Air Quality Standards. The Laurel SO_2 nonattainment area and the recently redesignated Billings SO_2 area are nearby. The Laurel SO_2 area is approximately 19.8 miles southwest of the Par refinery. The Billings SO_2 maintenance area is approximately 2 miles to the east of the Par refinery.

Applicants are required to comply with all laws relating to air, such as the Federal Clean Air Act, NAAQS set by the Environmental Protection Agency (EPA), and the Clean Air Act of Montana.

In addition, MAQP #1564-38 provides legally enforceable conditions regarding the emitting units themselves, pollution controls, and requires the applicant to take reasonable precautions to limit fugitive dust from this location.

Direct Impacts:
Direct construction impacts are expected to be minor and short-term. Emissions resulting from the proposed action would be limited based on the scope of work and be mostly contained inside the furnace facility. Limited external emission may result from the transport of demolished material.

Direct operational impacts are expected to be minor and long term based on the allowable increase in the facilities potential to emit. See permit analysis for more information regarding air quality impacts. The majority of pollutants from the proposed project would be related to the combustion of natural gas within the furnace facility. This would result in a minor increase in emissions of NO_X, CO, SO_X, VOCs, and particulate matter from the crude furnace.

CONTROLLED	tons/year						
Emission Source	**PM**	**PM_{10}**	**$PM_{2.5}$**	**NO_X**	**CO**	**VOC**	**SO_X**
Crude Furnace (F-1)	0.20	0.20	0.20	5.73	2.23	0.28	0.12
Total Emissions	**0.20**	**0.20**	**0.20**	**5.73**	**2.23**	**0.28**	**0.12**

The emission inventory for the proposed project is based on a yearly increase in operating hours for the crude furnace from 8,415 hours per year up to 8,741 hours per year and an increase in refinery fuel gas from 1331.5 MMSCF per year to 1384.7 MMSCF per year.

The emission inventory, located in Section IV of the MAQP Analysis, is based on emission factors derived and approved by DEQ and on limits proposed and approved as Best Available Control Technology (BACT). The emissions associated with the proposed permit increase emissions from the crude furnace facility.

While the emissions calculations in Section IV of the MAQP Analysis provide a conservative projected actual emissions increase based on the additional hours of operation, based on the efficiency upgrade emissions are anticipated to go down. The historical efficiency of the F-1 Furnace is approximately 81.8%. The design case for the F-1 Furnace upgrades is expected to be 87.0%, an efficiency increase of approximately 5%. For the same firing rate, that efficiency improvement would correlate to roughly 5% less fuel being used which would result in less emissions for F-1.

	Firing Rate (MMBtu/yr)	**Furnace Efficiency**	**Fuel Usage (MMscf/yr)**
Baseline/Historic	1,604,458	81.8%	1331.5
Future Operation	1,668,528	87.0%	1312.8

Secondary Impacts:

Secondary construction and operational impacts from the proposed project are expected to be negligible and short-term. Emissions would not be expected to cause or contribute to a violation of the health and welfare-based primary and secondary NAAQS. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. See permit analysis for more detailed information regarding air quality impacts. Any adverse impacts would be long-term and minor. No beneficial secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

Conditions and limits contained in the MAQP would limit emissions; therefore, any expected cumulative air quality impacts would be minor and short-term. Yellowstone County and the surrounding area also has other both minor and major stationary sources and all contribute to the overall air quality in Yellowstone County, Montana. The cumulative impacts of these other emitters and the proposed action would not have an adverse impact to air quality.

Impacts from the Proposed Action are limited by enforceable conditions and limits contained in the MAQP and BACT must be used.

Because emissions from the proposed project, and all other similar or related projects located in the affected area are regulated, any adverse cumulative impacts to air quality would be short- and long-term and minor.

4. Vegetation Cover, Quantity, and Quality

The affected area is an already developed petroleum refinery with little to no vegetative cover outside of what would be considered "land scaping" for aesthetics within the project boundaries. The proposed project is located within the existing property boundary of the refinery and will be confined to the crude furnace (F-1) facility.

Direct Impacts:
No direct construction or operational impacts to vegetative cover, quantity, or quality will occur as a result of the proposed project.

Secondary Impacts:
No secondary construction or operational impacts to vegetative cover, quantity, or quality will occur as a result of the proposed project.

Cumulative Impacts:
No cumulative impacts to vegetative cover, quantity, or quality will occur as a result of the current proposed project.

5. Terrestrial, Avian, and Aquatic Life and Habitats

The affected area is an already developed petroleum refinery with no terrestrial, avian, or aquatic life and habitats within the project boundaries or the crude furnace facility where the project is proposed.

Direct Impacts:
No direct impacts from construction or operational affects to terrestrial, avian, or aquatic life and habitats are expected as a result of the proposed project.

The affected area is an already developed petroleum refinery with no terrestrial, avian, or aquatic life or habitats located within the property boundary or more specifically, the crude furnace facility where the project is proposed to occur. There may be resident bird species (pigeons and other small avian species) located on the property, but it is unlikely that the proposed project would affect them due to the continuous operation of the refinery. Therefore, any species identified in the MTNHP reports, as discussed in Section 6, are unlikely displaced by construction activities would likely relocate to nearby, similar habitats.

Secondary Impacts:
No secondary impacts from construction or operations are expected as a result of the proposed project. The affected area is an already developed petroleum refinery with no terrestrial, avian, or aquatic life or habitats located within the property boundary or more specifically, the crude furnace facility where the project is proposed to occur.

Because the area surrounding the furnace facility site is already developed, no species are expected to be present.

Cumulative Impacts:
No cumulative impacts would be expected to terrestrial, avian and aquatic life.

6. Unique, Endangered, Fragile, or Limited Environmental Resources

DEQ conducted a search using the Montana Natural Heritage Program (MTNHP) webpage with file downloads saved to the AQB project file. The query was run and downloaded on January 2, 2025. The polygon selected was the immediate area surrounding the proposed site.

The proposed project is not in core, general or connectivity sage grouse habitat, as designated by the Sage Grouse Habitat Conservation Program at: http://sagegrouse.mt.gov.

Species of concern identified in the MTNHP report include the following:

Birds – Veery, Bald Eagle, Great Blue Heron, Pinyon Jan, Cassin's Finch, Brewer's Sparrow, and Sprague's Pipit

Fish – Sauger

Mammals – Spotted Bat, Little Brown Myotis, Northern Hoary Bat
Other – Bat Roost (non-cave)

Reptiles – Western Milksnake, Snapping Turtle, Spiny Softshell

Vascular Plant – Bractless Hedge-hyssop

All of these species are outside of the analysis area but included in the MTNHP polygon area.

Direct Impacts:
No direct construction or operational affects to unique, endangered, and fragile species or limited environmental resources are expected. The affected area is an already developed petroleum refinery with no terrestrial, avian, or aquatic life or habitats located within the property boundary or more specifically, the crude furnace facility where the project is proposed to occur.

The Sage Grouse Habitat Conservation Program has stated that the proposed project would not occur in core, general or connectivity sage grouse habitat. Therefore, impacts to sage grouse would not occur.

Secondary Impacts:
No secondary construction or operational affects to unique, endangered, and fragile species or limited environmental resources are expected are expected with the proposed project.

As stated previously, the affected area is an already developed petroleum refinery with no terrestrial, avian, or aquatic life or habitats located within the property boundary and more specifically, the crude furnace facility where the project is proposed to occur.

Cumulative Impacts:
No cumulative impacts would be expected.

7. Historical and Archaeological Sites

The Montana State Historic Preservation Office (SHPO) was notified of the application and SHPO conducted a file search and provided a letter dated January 2, 2025.

Site Name	Twp	Rng	Sec	Qs	Site Type 1	Site Type 2	Time Period	Owner	NR Status
24YL1995	1N	26E	24	Comb	Historic Exploration		1859 and earlier	No Date	Undetermined
24YL0271	1N	26E	25	Comb	Historic Irrigation System		1910-1919	Private	Ineligible
24YL0272	1N	26E	24	Comb	Historic Irrigation System		1890-1899	Private	Ineligible
24YL0272	1N	26E	25		Historic Irrigation System		1890-1899	Private	Ineligible
24YL0277	1N	26E	25		Historic Railroad		Historic More Than One Decade	Private	Eligible
24YL0277	1N	26E	25		Historic Railroad		Historic More Than One Decade	Private	Eligible
24YL1672	1N	26E	25		Historic Railroad		Historic More Than One Decade	State Owned	Eligible

It is SHPO's position that any structure over fifty years of age is considered historic and is potentially eligible for listing on the National Register of Historic Places. If any structures are within the Area of Potential Effect, and are over fifty years old, SHPO recommends that they be recorded, and a determination of their eligibility be made prior to any disturbance taking place.

No underground disturbance would be required for the proposed action as the there is no new ground disturbances for the proposed actions.

Direct Impacts:
No direct construction or operational impacts to historical or archaeological sites are expected with the proposed actions. According to the SHPO, there have been seven (7) previously recorded

historical or archaeological sites identified within the search area. The same rationale would apply here, as long as the land marker was undisturbed, no impact would occur. Therefore, no direct impacts from construction activities would be expected because of the proposed project.

Secondary Impacts:
No secondary construction or operational impacts to historical or archaeological are expected with the proposed project. According to the State Historical Preservation Society, there has been one previously recorded historical or archaeological site identified within the search area.

The site was identified as a historic road. As there are no new ground disturbance associated with the project and impacts to the historic road would be limited to vehicle traffic and not considered specific to the project.

Cumulative Impacts:
No cumulative impacts are expected as a result of the proposed project.

8. Aesthetics

Direct Impacts:

No direct construction or operational impacts to aesthetics are associated with the proposed actions. The proposed project will occur inside the current crude furnace facility. The affected area is an already developed crude oil refinery with no new structures associated with the proposed project being constructed.

Secondary Impacts:
Negligible and short-term impacts may occur as a result of the construction activity associated with the proposed action. Impacts to the aesthetics may include heavy vehicle traffic used to deliver materials required to refurbish the furnace facility. Along with heavy vehicle traffic, loading equipment may also be present on-site during construction.

No operational secondary impacts are expected as a result of the proposed permit action. There are no new facilities anticipated with the furnace refurbishment.

Cumulative Impacts:
With this permitting action, negligible short-term cumulative impacts on the aesthetics are anticipated as the site is an already developed petroleum refinery with no new structures anticipated.

9. Demands on Environmental Resources of Land, Water, Air, or Energy

The proposed project is small by industrial standards and is located within the Par property boundaries.

Direct Impacts:
No direct construction or operational impacts to environmental resources of land or water

as the proposed project does not require any new land disturbances or use of water. No direct construction impacts to the environmental resources of air or energy are expected. However, minor and long-term operational impacts are expected to environmental resources of air and energy. The proposed permit action would emit additional pollutants (air) associated with the increase in natural gas (energy) consumption. Emissions increase can be seen in Section 3, Air Quality of this assessment as well as the Section 4 – Emissions Inventory of the MAQP Analysis.

Secondary Impacts:
No secondary impacts to environmental resources of land, water, air, or energy are expected with the proposed project.

Cumulative Impacts:
Negligible, long-term cumulative impacts on environmental resources of air and energy are anticipated as a result of this permitting action through the increase in fuel usage on a yearly basis.

No cumulative impacts to land and water are expected. There are no new facilities being constructed and water is not part of the crude furnace operations.

10. Impacts on Other Environmental Resources

The affected is located within the Par refinery property.

Direct Impacts:
Fugitive dust emissions resulting from construction of the proposed facility may adversely impact air quality in the affected area. However, Par must use reasonable precautions to limit fugitive dust generated from construction activities; therefore, the proposed project would not be expected to cause or contribute to a violation of the applicable NAAQS for particulate matter (fugitive dust). See permit analysis for more detailed information regarding air quality impacts. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. Therefore, any adverse direct impacts to other environmental resources would be short-term and minor. No beneficial direct impacts would be expected because of the proposed project.

Secondary Impacts:
Proposed operations would not be expected to cause or contribute to a violation of the public welfare-based Secondary NAAQS. See permit analysis for more detailed information regarding air quality impacts. Secondary NAAQS provide public welfare protection, including protection against decreased visibility and damage to animals, crops, vegetation, and buildings. Therefore, any adverse secondary impacts to other environmental resources would be long-term and minor. No beneficial secondary impacts would be expected because of the proposed project.

Cumulative Impacts:
No other environmental resources, beyond the resource areas already covered within this EA would result in any known additional cumulative impacts.

11. Human Health and Safety

Direct Impacts:
Construction activities involve the potential for adverse direct impacts to human health and safety. However, construction operations would be subject to OSHA standards, which are designed to be protective of human health and safety. Further, residents of the affected area would not be allowed on-site during construction of the proposed facility.

Also, fugitive dust emissions resulting from construction of the proposed facility may adversely impact air quality in the affected area. However, Par must use reasonable precautions to limit fugitive dust generated from construction activities; therefore, the proposed project would not be expected to cause or contribute to a violation of the applicable NAAQS for particulate matter (fugitive dust). See permit analysis for more detailed information regarding air quality impacts. Primary NAAQS provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. Therefore, any adverse direct impacts to human health and safety would be short-term and negligible to minor.

Secondary Impacts:
Operation of the proposed facility would be subject to OSHA standards. OSHA standards are designed to be protective of human health and safety. Further, operation of the furnace would emit regulated air pollutants. However, emissions from the proposed project would use BACT and thus would not be expected to cause or contribute to a violation of the human health-based Primary NAAQS. See permit analysis for more information regarding air quality impacts. Primary NAAQS provide public health protection, including protecting the health of "sensitive" populations such as asthmatics, children, and the elderly. Therefore, any adverse secondary impacts to human health and safety would be long-term and negligible to minor. No beneficial secondary impacts would be expected because of the proposed project.

Cumulative Impacts:
No cumulative impacts to human health and safety are anticipated as a result of the proposed permitting action because the emissions as described in Section IV of the Permit Analysis would be considered small by industrial standards.

12. Industrial, Commercial, and Agricultural Activities and Production

Direct Impacts:
No construction or operational direct impacts to commercial or agricultural activities and production are expected because the site is an industrial site with no commercial, agricultural, or production activities.

Minor and short-term impacts may occur as a result of the construction activities. The crude furnace facility will be non-operational during the proposed project and is expected to last up to 60 days. Positive minor and long-term operational impacts are expected as a result of the proposed project through the replacement of current refinery gas fuel burners with new "in-kind" natural gas-fired burners, new crude piping fitted with finned tubers to increase thermal absorption, and refractory material repair or replacement resulting in increase in overall thermal efficiency for the crude furnace (F-1).

Secondary Impacts:
Industrial activities in the affected area would increase because of the proposed project. Therefore, any secondary impacts to industrial activities and production would be long-term, minor, and beneficial. No adverse direct impacts would be expected because of the proposed project.

Cumulative Impacts:
Once the project is completed, the crude furnace will operate in a more efficient manner, resulting in less fuel consumed to produce an equivalent amount of product. Cumulatively, these operations provide an important industrial base to the area. These impacts would be long term and beneficial. No Cumulative impacts on agricultural, commercial or production activities would be expected.

13. Quantity and Distribution of Employment

Direct Impacts:
Par would use existing staff or contracted services to construct the proposed facility. Therefore, any direct impacts to the quantity and distribution of employment in the affected area would be short-term, negligible, and beneficial. No adverse direct impacts would be expected because of the proposed project.

Secondary Impacts:
Par would use existing staff to operate the proposed facility. Therefore, any secondary impacts to the quantity and distribution of employment in the affected area would be long-term, negligible, and beneficial. No adverse secondary impacts would be expected because of the proposed project.

Cumulative Impacts:
No cumulative impact is expected on long-term employment from the proposed action because the new facility would not be expected to create any permanent new jobs.

14. Local and State Tax Base and Tax Revenues

The proposed project would be small by industrial standards and the amount of time and resources necessary to accommodate refurbishment of the proposed facility would be relatively limited.

Direct Impacts:
No direct construction or operational impacts to local state tax base and tax revenues would be expected with the proposed project.

Secondary Impacts:
Local, state and federal governments would be responsible for appraising the property, setting tax

rates, collecting taxes, from the companies, employees, or landowners benefitting from the proposed operation. Further, Par would be responsible for accommodation of any increased taxes associated with operation of the proposed facility. Therefore, any secondary impacts would be negligible to minor, consistent with existing impacts in the affected area, and beneficial. No adverse secondary impacts would be expected because of the proposed project.

Cumulative Impacts:
Long-term beneficial negligible to minor impacts to local and state tax base and tax revenues are anticipated from this permitting action.

15. Demand for Government Services

Direct Impacts:
The air quality permit has been prepared by state government employees as part of their day-to-day, regular responsibilities. Therefore, any adverse direct impacts to demands for government services is consistent with existing impacts and negligible. No beneficial direct impacts would be expected because of the proposed project.

Secondary Impacts:
Following construction of the proposed facility, initial and ongoing compliance inspections of facility operations would be accomplished by state government employees as part of their typical, regular duties and required to ensure the facility is operating within the limits and conditions listed in the air quality permit. Therefore, any adverse secondary impacts to demands for government services would be consistent with existing impacts and negligible. No beneficial secondary impacts would be expected because of the proposed project.

Cumulative Impacts:
Minor cumulative impacts are anticipated on government services with the proposed action and a minimal increase in impact would occur but regulators would likely combine visits to cover regulatory oversight needs.

16. Locally Adopted Environmental Plans and Goals

DEQ has reviewed the Yellowstone County website and found no locally adopted environmental plans and goals for the area. Par has indicated, in application number 1564-38_2024_12_20_APP that no known state, county, city, USFS, BLM, or tribal zoning or management plans and goals are known to potentially affect the site**.**

Direct Impacts:
No locally adopted environmental plans and goals were identified. Therefore, no direct impacts would be expected because of the proposed project.

Secondary Impacts:
No locally adopted environmental plans and goals were identified.; therefore, no secondary impacts to locally adopted environmental plans and goals would be expected because of the proposed

project.

Cumulative Impacts:
No cumulative impacts to the locally adopted environmental plans and goals are anticipated since no direct impacts or secondary impacts were identified.

17. Access to and Quality of Recreational and Wilderness Activities

The affected area is located within the Par Montana property boundary. The Yellowstone River boarders the property on the north side with woodland to the east and industrial property to the south and west.

Direct Impacts:
No recreational or wilderness areas occur in the vicinity of the proposed project. Therefore, no direct impacts to access and quality of recreational and wilderness activities would be expected because of the construction phase of the proposed project.

Secondary Impacts:
The affected area is primarily a heavy industrial facility. No recreational or wilderness areas occur in the immediate area; therefore, no secondary impacts to access and quality of recreational and wilderness activities would be expected because of proposed facility operations.

Cumulative Impacts:
No cumulative impacts to access and quality of recreational and wilderness activities are anticipated as a result of the proposed permitting action as there are no public recreational or wilderness activity sites with 10 miles of the proposed project.

18. Density and Distribution of Population and Housing

The affected area is primarily a heavy industrial site with no housing located within the Par Montana property boundary.

Direct Impacts:
Par would employ existing staff and/or contracted services to construct the facility and the proposed project would not be expected to otherwise result in an increase or decrease in the local population. Therefore, no direct impacts to density and distribution of population and housing would be expected because of the proposed project.

Secondary Impacts:
Par would employ existing staff to operate the facility and the proposed project would not be expected to otherwise result in an increase or decrease in the local population. Therefore, no secondary impacts to density and distribution of population and housing would be expected because of the proposed project.

Cumulative Impacts:
No cumulative impacts to density and distribution of population and housing are anticipated as a result of the proposed permitting. There are no impacts on the density and distribution of population and housing.

19. Social Structures and Mores

DEQ is not aware of any Native American cultural concerns that would be affected by the proposed activity. Based on the information provided by the Par, it is not anticipated that this project would disrupt traditional lifestyles or communities. A State Historical Preservation Office cultural inventory is noted in Section 7 of the EA.

Direct Impacts:
Construction and operation of the facility would not be expected to affect the existing customs and values of the affected population. Therefore, no direct impacts to the existing social structures and mores of the affected population would be expected because of the proposed project.

Secondary Impacts:
The existing nature of the area affected by the proposed project is heavy industrial (petroleum refinery); therefore, operation of the facility would not be expected to affect the existing customs and values of the affected population. Therefore, no secondary impacts to the existing social structures and mores of the affected population would be expected because of the proposed project.

Cumulative Impacts:
The proposed project has negligible to minor cumulative impacts on the existing social structures because this site is currently used as a petroleum refinery.

20. Cultural Uniqueness and Diversity

The existing nature of the area affected by the proposed project is heavy industrial (petroleum refinery). It is not anticipated that this project would cause a shift in some unique quality of the area.

Direct Impacts:
Par would employ existing staff and/or contracted services to construct the facility and thus the proposed project would not be expected to otherwise result in an increase or decrease in the local population. Therefore, no direct impacts to the existing cultural uniqueness and diversity of the affected population would be expected because of the proposed project.

Secondary Impacts:
The existing nature of the area affected by the proposed project heavy industrial (petroleum refinery). Further, Par would employ existing staff to operate the facility and

thus the proposed project would not be expected to result in an increase or decrease in the local population. Therefore, no secondary impacts to the existing cultural uniqueness and diversity of the affected population are anticipated as a result of the proposed action.

Cumulative Impacts:
No cumulative impacts to cultural uniqueness and diversity are anticipated because the skills required by this project would be similar to other existing sites in the area and this project would be considered small by industrial standards.

21. Private Property Impacts

The proposed project would take place on privately owned land. DEQ's approval of MAQP #1564-38 permit would not affect the applicant's real property. DEQ has determined that the permit conditions are reasonably necessary to ensure compliance with applicable requirements under the Montana Clean Air Act.

Therefore, DEQ's approval of MAQP #1564-38 would not have private property-taking or damaging implications.

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

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

YES	NO	
	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)

22. Other Appropriate Social and Economic Circumstances

Direct Impacts:

DEQ is unaware of any other appropriate short-term social and economic circumstances in the affected area that may be directly impacted by the proposed project. Due to the nature of the proposed action, no further direct impacts would be expected because of the proposed project.

Secondary Impacts:

The proposed project would refurbish the existing crude furnace facility and increase overall thermal efficiency. Any impacts to air quality from improving thermal efficiency of the crude furnace would be long-term, minor, and beneficial.

DEQ is unaware of any other appropriate long-term social and economic circumstances in the affected area that may be impacted by the proposed project. No further secondary impacts would be expected because of the proposed project.

Cumulative Impacts:

No cumulative impacts to any other appropriate social and economic circumstances are anticipated because no direct and secondary impacts were identified. The proposed project would take place on private land. DEQ has determined that the permit conditions are reasonably necessary to ensure compliance with applicable requirements under the Montana Clean Air Act. Therefore, DEQ's approval of MAQP #1564-38 would not have private property-taking or damaging implications.

23. Other Appropriate Social and Economic Circumstances

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

24. Greenhouse Gas Assessment

The proposed project will update the Crude Furnace (F-1) facility. As part of the updates, Par will install and operate new "in-kind" natural gas-fired burners, install new crude oil pipelines throughout the facility, and repair or replace any refractory materials.

The analysis area for this resource is limited to the activities regulated by the issuance of MAQP #1564-38 which provides an increase in operational hours and fuel usage. The GHG emissions were calculated from the proposed projects operations increase of 336 hours per year and fuel increase of 53.2 million standard cubic feet per year.

For the purpose of this analysis, DEQ has defined greenhouse gas emissions as the following gas species: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and many species of fluorinated compounds. The range of fluorinated compounds includes numerous chemicals which are used in many household and industrial products. Other pollutants can have some properties that also are similar to those mentioned above, but the EPA has clearly identified the species above as the primary Greenhouse Gases (GHGs). Water vapor is also technically a greenhouse gas, but its properties are controlled by the temperature and pressure within the atmosphere, and it is not considered an anthropogenic species.

Montana recently used the EPA State Inventory Tool (SIT) to develop a greenhouse gas inventory. This tool was developed by EPA to help states develop their own greenhouse gas inventories, and this relies upon data already collected by the federal government through various agencies. The inventory specifically deals with CO_2, CH_4, and N_2O and reports the total as CO_2e.

The SIT consists of eleven Excel based modules with pre-populated data that can be used as default settings or in some cases, allows states to input their own data when the state believes their own data provides a higher level of quality and accuracy. Once each of the eleven modules is filled out, the data from each module is exported into a final "synthesis" module which summarizes all of the data into a single file. Within the synthesis file, several worksheets display the output data in a number of formats such as emissions by sector and emissions by type of greenhouse gas. The SIT data is currently updated through the year 2021, as it takes several years to validate and make new data available within revised modules.

The combustion of natural gas at the site would release GHGs primarily being CO_2, N_2O, and much smaller concentrations of incomplete combustion of fuel components including CH_4 and other volatile organic compounds (VOCs).

Mobile emissions associated with this action are limited to construction of the site. This amount is insignificant and not included in the assessment. Additionally, there are no compressed gases, fire suppressants or refrigerants/air conditioning associated with this project which would have been considered Scope 1 emissions.

Direct Impacts

Operation of natural gas-fired crude furnaces for the proposed project would produce exhaust fumes containing GHGs. DEQ has calculated GHG emissions using the EPA Simplified GHG

Calculator version May 2023, for the purpose of totaling GHG emissions. This tool totals CO_2, N_2O, and CH_4 and reports the total as CO_2 equivalent (CO_2e) in metric tons CO_2e. If there are also fluorinated compounds associated with the project those may also be input into the GHG calculator. The calculations in this tool are widely accepted to represent reliable calculation approaches for developing a GHG inventory.

Application information indicates that an increase of 53.2 million standard cubic feet (mmscf) of natural gas would be utilized per year. To account for variability due to the factors described above, DEQ has calculated the emissions using the maximum value of the Applicant's estimate, using 158,333 scf/hr and a heat value of 1205 Btu per scf.

Using the EPA's simplified GHG Emissions Calculator for sources, a maximum of 2,896.3 metric tons of CO_2e would be produced per year of operation.

Secondary Impacts

GHG emissions contribute to changes in atmospheric radiative forcing, resulting in climate change impacts. GHGs act to contain solar energy loss by trapping longer wave radiation emitted from the Earth's surface and act as a positive radiative forcing component (BLM 2021). If a reader would like further details please see the BLM 2022 report at: Annual GHG Report.

The impacts of climate change throughout the Northern Great Plains of Montana include changes in flooding and drought, rising temperatures, and the spread of invasive species (BLM 2021).

Cumulative Impacts

As previously described, the F-1 Furnace is undergoing efficiency upgrades. While the emissions calculations in Appendix B of the Par Montana permit application 1564-38_2024_12_20_APP Analysis provide a conservative projected actual emissions increase based on the additional hours of operation, based on the efficiency upgrade GHG emissions are anticipated to go down.
The historical efficiency of the F-1 Furnace is approximately 81.8%. The design case for the F-1 Furnace upgrades is expected to be 87.0%, an efficiency increase of approximately 5%. For the same firing rate, that efficiency improvement would correlate to roughly 5% less fuel being used.

Using the associated heat input/firing rate for the baseline period of 1331.5 million standard cubic feet of refinery fuel gas (equating to 1,604,458 MMBtu/yr), the past operations would result in 104,797 tpy of CO_{2e}, as shown/calculated in Appendix B of the permit application.

Including the increased firing rate associated with the additional two weeks of operation and then applying the efficiency improvement to that firing rate (specifically using less fuel as shown) would result in the values below, showing an overall reduction in GHG emissions of approximately 1,482 tpy of associated with this project.

	Firing Rate (MMBtu/yr)	**Furnace Efficiency**	**Fuel Usage (MMscf/yr)**	**CO_{2e} (tpy)**
Baseline/Historic	1,604,458	81.8%	1331.5	104,797
Future Operation	1,668,528	87.0%	1312.8	103,315
Decrease in GHG				**1,482**

DEQ has determined that the use of the default data provides a reasonable representation of the GHG inventory for all of the state sectors, and an estimated annual GHG inventory by year. At present, Montana accounts for 47.77 million metric tons of CO_2e based on the EPA State Inventory Tool for the year 2021. This project may contribute up to 0.002896 million metric tons per year of CO_2e. The estimated emission of 0.002896 million metric tons of CO_2e from this project would contribute 0.0000606% of Montana's annual CO_2e emissions.

Since CO2e is a global impact, DEQ has tried to show the amount this Proposed Action would have compared to Montana's cumulative CO_2e number and to show a reader the amount of change. This analysis is beyond just isolation and is trying to show a global change within a scale a reader can understand.

GHG emissions that would be emitted as a result of the proposed activities would add to GHG emissions from other sources.

PROPOSED ACTION ALTERNATIVES

No Action Alternative: In addition to the proposed action, DEQ must also considered a "no action" alternative. The "no action" alternative would deny the approval of MAQP #1564-38. The applicant would lack the authority to conduct the proposed activity. Any potential impacts that would result from the proposed action would not occur. The no action alternative forms the baseline from which the impacts of the proposed action can be measured.
If the Applicant demonstrates compliance with all applicable rules and regulations required for approval, the "no action" alternative would not be appropriate.

Other Reasonable Alternative(s): No other alternatives were considered.

CONSULTATION

DEQ engaged in internal and external efforts to identify substantive issues and/or concerns related to the proposed project. Internal scoping consisted of internal review of the environmental assessment document by DEQ staff. External scoping efforts also included queries to the following websites/databases/personnel:
https://www.yellowstonecountymt.gov/

A review of the Yellowstone County website, and listed department information did not indicate any specific planning documents that would be relative to this permitting action.

MAQP #1564-38 Application, EPA State Inventory Tool, and the EPA GHG Calculator Tool, State Historical Preservation Office, and NRIS.

PUBLIC INVOLVEMENT

The public comment period for this permit action was from 01/29/2025 through 02/13/2025.

OTHER GOVERNMENTAL AGENCIES WITH JURISDICTION

The proposed project would be located on private land. All applicable state and federal rules must be adhered to, which, at some level, may also include other state, or federal agency jurisdiction.

This environmental review analyzes the proposed project submitted by the Applicant. The project would be negligible and would be fully reclaimed to the permitted postmining land uses at the conclusion of the project and thus would not contribute to the long-term cumulative effects of mining in the area.

NEED FOR FURTHER ANALYSIS AND SIGNIFICANCE OF POTENTIAL IMPACTS

When determining whether the preparation of an environmental impact statement is needed, DEQ is required to consider the seven significance criteria set forth in ARM 17.4.608, which are as follows:

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

CONCLUSIONS AND FINDINGS

DEQ finds that this action results in negligible impacts to air quality and GHG emissions in Yellowstone County, Montana.

No significant adverse impacts would be expected because of the proposed project. As noted through the draft EA, the severity, duration, geographic extent and frequency of the occurrence of the impacts associated with the proposed air quality project would be limited. The proposed action would result in the refurbishment of the crude furnace (F-1) facility.

The Applicant is proposing to replace refinery fuel gas burners with new (in-kind) refinery fuel gas burners, replace existing crude piping with uniform piping fitted with finned tubes to increase thermal absorption, and repair or replace refractory materials within the furnace facility. The site would be permitted to operate F-1 furnace 8,760 hours per calendar year using BACT for the control of emissions from the proposed operations.

As discussed in this EA, DEQ has not identified any significant impacts associated with the proposed actions for any environmental resource. DEQ does not believe that the activities proposed by the Applicant would have any growth-inducing or growth-inhibiting aspects, or contribution to cumulative impacts. The proposed project site does not appear to contain known unique or fragile resources.

There are no unique or known endangered fragile resources in the project area and no underground disturbance would be required for this project.

There would be negligible impacts to view-shed aesthetics as the refinery is an established part of the local community. The refinery will continue to be visible to the surrounding populace.

Demands on the environmental resources of land, water, air, or energy would be negligible.

Impacts to human health and safety would be insignificant.

As discussed in this EA, DEQ has not identified any significant impacts associated with the proposed activities on any environmental resource.

Issuance of a Montana Air Quality Permit #1564-38 to the Applicant does not set any precedent that commits DEQ to future actions with significant impacts or a decision in principle about such future actions. If the Applicant submits another modification or proposes to amend the permit, DEQ is not committed to issuing those revisions.

DEQ would conduct an environmental review for any subsequent permit modifications sought by the Applicant pursuant to MEPA. DEQ would make permitting decisions based on the criteria set forth in the Clean Air Act of Montana.

Issuance of the Permit to the Applicant does not set a precedent for DEQ's review of other applications for Permits, including the level of environmental review. The level of environmental review decision is made based on case-specific consideration of the criteria set forth in ARM 17.4.608.

Finally, DEQ does not believe that the proposed air quality permitting action by the Applicant would have any growth-inducing or growth inhibiting impacts that would conflict with any local, state, or federal laws, requirements, or formal plans.
Based on a consideration of the criteria set forth in ARM 17.4.608, no significant adverse impacts to the affected human environment would be expected because of the proposed project. Therefore, preparation of an Environmental Impact Statement or EIS is not required, and the draft EA is deemed the appropriate level of environmental review pursuant to MEPA.

Preparation and Approval

EA and Significance Determination prepared by:

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EA Reviewed By:

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EA Approved By:

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REFERENCES

- 1564-38_2024_12_20_APP – Application received from Tetra Tech, Inc., on behalf of Par Montana, LLC. on December 20, 2024.

- EPA GHG Calculator Tool https://www.epa.gov/statelocalenergy/state-inventory-and-projection-tool

- EPA State Inventory Tool, https://www.epa.gov/statelocalenergy/state-inventory-and-projection-tool

- 2021 BLM Specialist Report on Annual Greenhouse Gas Emissions and Climate Trends, https://www.blm.gov/

- https://www.blm.gov/content/ghg/?year=2022

- 1564-38_2024_12_31_SHPO – State Historical Preservation Office Investigation

- 1564-38_NRIS – Natural Resource Information System Endangered Species Investigation, https://mtnhp.org

- https://www.yellowstonecountymt.gov/

- Olson, J.L., and Reiten, J.C., 2002, Hydrogeology of the west Billings area: Impacts of land-use changes on water resources: Montana Bureau of Mines and Geology Report of Investigation 10, 32 p., 2 sheets.