ENERGY
TRANSFER

April 14, 2023

Ms. Cynthia Kaleri
Chief, Air Permits Section
Environmental Protection Agency Region VI
1201 Elm Street
Dallas, TX 75270
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RE: Response to Clean Air Act (CAA) New Source Review (NSR) Permit and Title V Permit Applications for the Blue Marlin Offshore Port (BMOP) – Information Request Response

Dear Ms. Kaleri:

Blue Marlin Offshore Port (BMOP), LLC is providing the U.S. Environmental Protection Agency (EPA) Region 6 revisions to the following applications for a proposed Deepwater Port (DWP) Project, previously submitted on September 28, 2020, with supplements filed on January 29, 2021, and September 7, 2021.

- A revised CAA NSR Prevention of Significant Deterioration (PSD) Pre-construction Permit Application; and
- A revised CAA Title V Permit Application.

The Environmental Protection Agency (EPA) provided an information request for the offshore portion of the DWP Project by letter dated September 13, 2022. In this letter the EPA stated their belief that the National Emission Standards for Hazardous Air Pollutants (NESHAP) for Marine Tank Vessel Loading Operations (40 CFR Part 63, Subpart Y) applies to BMOP's proposed DWP Project.

BMOP is submitting these revised applications to reflect an update to the Project to address applicability to 40 CFR Part 63, Subpart Y. In response, BMOP has updated the applications to include a vapor capture system for marine vessel loading, with control by vapor combustion units (VCUs). As a result of this update to meet EPA's request, the DWP Project now requires PSD review for oxides of nitrogen (NO_X), carbon monoxide (CO), particulate matter with an aerodynamic diameter less than 10 microns (PM_{10}), particulate matter with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$), and greenhouse gases (GHGs), in addition to volatile organic compounds (VOC). The enclosed PSD and Title V applications have been updated accordingly.

BMOP appreciates the EPA's continued review of the PSD and Title V application for the DWP Project. If you have any questions or comments about the information presented in this letter, please contact Lisa Garcia, Sr. Manager – Engineering, E&C Environmental, Energy Transfer, at (713) 989-7762 or email at Lisa.Garcia@energytransfer.com.

Sincerely,

Gregory Mcilwain
SVP – operations
Energy Transfer Partners, LLC

cc: Ashley Mohr, EPA R6, ashley.mohr@epa.gov

Enclosures

PREVENTION OF SIGNIFICANT DETERIORATION AIR CONSTRUCTION PERMIT APPLICATION

PSD Volume 1

BLUE MARLIN OFFSHORE PORT LLC

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April 2023

Project 191001.0117

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY **1-1**
1.1 Air Permit Applicability Overview 1-2
1.2 Application Contents 1-2

2. PROJECT DESCRIPTION **2-1**
2.1 Project Overview 2-1
2.2 Proposed Schedule 2-6

3. EMISSIONS QUANTIFICATION **3-1**
3.1 Potential Emissions Summary 3-1
3.2 Detailed Emissions Calculations 3-2
3.3 WC 509 Platform Support Equipment Emissions 3-10

4. REGULATORY ANALYSIS **4-1**
4.1 Federal Permitting Programs 4-1
4.2 Air Quality Regulations 4-3

5. BACT ANALYSIS **5-1**
5.1 BACT Definition 5-1
5.2 BACT Assessment Methodology 5-3
5.3 BACT "Top Down" Approach 5-4
5.4 Defining the Source 5-7
5.5 VOC BACT – Marine Loading 5-9
5.6 VOC BACT – Large Non-Emergency Natural Gas Fired Generators 5-21
5.7 VOC BACT – Large Emergency Diesel Firewater Pump 5-23
5.8 VOC BACT – Small Emergency Diesel Generator 5-25
5.9 VOC BACT – Small Non-Emergency Diesel Crane Engines 5-28
5.10 VOC BACT – Fugitive Emissions 5-30
5.11 VOC BACT – Storage Vessels 5-32
5.12 CO BACT – Large Non-Emergency Natural Gas-Fired Generators 5-33
5.13 CO BACT – Large Emergency Diesel Firewater Pumps 5-35
5.14 CO BACT – Small Emergency Diesel Generators 5-37
5.15 CO BACT – Small Non-Emergency Diesel Crane Engines 5-38
5.16 NO_x BACT – Large Non-Emergency Natural Gas-Fired Generators 5-40
5.17 NO_x BACT – Large Emergency Diesel Firewater Pumps 5-44
5.18 NO_x BACT – Small Emergency Diesel Generator 5-46
5.19 NO_x BACT – Small Non-Emergency Diesel Crane Engines 5-47
5.20 $PM_{10}/PM_{2.5}$ BACT – Large Non-Emergency Natural Gas Fired Generators 5-48
5.21 $PM_{10}/PM_{2.5}$ BACT – Large Emergency Diesel Firewater Pumps 5-50
5.22 $PM_{10}/PM_{2.5}$ BACT – Small Emergency Diesel Engines 5-52
5.23 $PM_{10}/PM_{2.5}$ BACT – Small Non-Emergency Diesel Crane Engines 5-53
5.24 GHG BACT – Large Non-Emergency Natural Gas Fired Generators 5-54
5.25 GHG BACT – Large Emergency Diesel Firewater Pumps 5-57
5.26 GHG BACT – Small Emergency Diesel Generators 5-58
5.27 GHG BACT – Small Non-Emergency Diesel Crane Engines 5-60

APPENDIX A. SITE MAPS AND PLOT PLANS **A-1**

APPENDIX B. LDEQ FORMS B-1

APPENDIX C. DETAILED EMISSIONS CALCULATIONS C-1

APPENDIX D. BACT SUPPORTING DOCUMENTATION D-1

APPENDIX E. MAINTENANCE ALLOWANCE APPLICATION PER 40 CFR § 63.562(B)(6) E-1

LIST OF FIGURES

Figure 2-1. Project Overview Map 2-2

Figure 2-2. Existing WC 509 Platform Complex 2-3

Figure 2-3. Schematic of the Proposed WC 509 Platform Complex 2-6

Figure 5-1. Example Vapor Combustion System 5-12

Figure 5-2. Vapor Recovery Onboard a North Sea Shuttle Tanker 5-14

LIST OF TABLES

Table 1-1. Proposed VOC BACT Summary 1-3

Table 1-2. Proposed CO BACT Summary 1-3

Table 1-3. Proposed NO_X BACT Summary 1-4

Table 1-4. Proposed $PM_{10}/PM_{2.5}$ BACT Summary 1-4

Table 1-5. Proposed GHG BACT Summary 1-5

Table 2-1. DWP Components for Offshore Loading 2-5

Table 3-1. Potential Emissions Summary 3-1

Table 3-2. Marine Loading Emissions Specifications 3-4

Table 3-3. Summary of UPL by HAP, Liquid Mass Percent 3-7

Table 3-4. Summary of UPL by HAP, Vapor Mass Percent 3-7

Table 3-5. Crude Oil Vapor HAP Speciation 3-8

Table 3-6. Potential VOC and HAP Mass Emissions from Uncaptured Marine Loading 3-9

Table 3-7. Storage Tank Representation 3-14

Table 4-1. Major Stationary Source Determination 4-2

Table 4-2. Project Emissions Increase Evaluation 4-2

Table 5-1. Rank of Remaining VOC Control Technologies for Marine Loading 5-19

Table 5-2. Added Emissions as a Result of the VCU Control of Marine Loading 5-20

1. EXECUTIVE SUMMARY

Blue Marlin Offshore Port LLC (the Applicant) is proposing to develop the Blue Marlin Offshore Port (BMOP) Project (Project) in the Gulf of Mexico (GOM) to provide United States (U.S.) crude oil loading services onto very large crude carriers (VLCCs), and other crude oil carriers, for export to the global market.

The primary purpose of the Project will be to provide for safe and reliable long-term supply of crude oil for export to the global market. To accomplish this purpose, BMOP will repurpose an existing subsea pipeline within the Stingray Pipeline System to transport crude oil to the proposed deep water port (DWP). This DWP will be located in federal waters within Outer Continental Shelf (OCS) West Cameron Lease Block (WC) 509, WC 508, and East Cameron (EC) Block 263. At the DWP location, VLCCs and other crude oil carriers (collectively referred to as "crude oil carriers" in this report), will moor at one of two Catenary Anchor Leg Mooring (CALM) Buoys, a type of Single Point Mooring (SPM) buoy system. Floating crude oil hoses will be connected to the buoy to support crude oil loading. Up to 275 VLCCs or other crude oil carriers may be loaded per year.

In response to EPA's September 13, 2022, request, BMOP has added vapor capture and control for the loading of the crude oil carriers at the proposed DWP. The vapor capture and control system will include floating vapor return hoses, which will be connected to the crude oil carriers along with the floating crude oil hoses. Displaced vapors from the crude oil carrier will be routed through the floating vapor return hoses back to the CALM buoys. Separate submerged hoses will carry the vapors from the buoys to the pipeline end manifold (PLEM) at the sea floor, and a looped subsea vapor return pipeline will route the vapors from the PLEMs back to the WC 509 Platform Complex. A dock safety skid and vapor blowers will be added to the WC 509 Platform Complex. The captured vapors (expected 99% capture efficiency) will be routed to three (3) vapor combustion units (VCUs), which will have an average destruction and removal efficiency (DRE) for volatile organic compounds (VOCs) of 95%, during routine loading operations.

The proposed project will require a DWP license in accordance with the Deep Water Port Act (DWPA). The U.S. Environmental Protection Agency (EPA) is identified as a cooperating agency in the review of a DWP license, in accordance with Title 33 of the Code of Federal Regulations (CFR) §148.3(d). The DWPA also requires evaluation of the DWP in accordance with the Clean Air Act (CAA). The Project consists of both onshore and offshore components. As defined in 33 CFR §148.5, a deep water port is:

> *"[A]ny fixed or floating manmade structures other than a vessel, or any group of structures, located beyond State seaward boundaries that are used or are intended for use as a port or terminal for the transportation, storage, or further handling of oil or natural gas for transportation to any State, except as otherwise provided in the Deepwater Port Act of 1974, as amended, and for other uses not inconsistent with the purposes of the Deepwater Ports Act, including transportation of oil or natural gas from the United States' OCS… Must be considered a 'new source' for the purposes of the Clean Air Act…"*

As such, this application is being re-submitted to the EPA Region 6 for a Prevention of Significant Deterioration (PSD) air permit to authorize the direct emissions sources proposed for the DWP under the CAA New Source Review (NSR) program.

1.1 Air Permit Applicability Overview

The DWP site will be approximately 82 statute miles off the coast of Cameron Parish, Louisiana, with an approximate water depth of 156 to 162 feet.[1] The nearest Parish onshore is Cameron Parish, Louisiana. Cameron Parish is designated by EPA as "attainment" or "unclassifiable" with the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants.[2] Therefore, the Project is not subject to Nonattainment New Source Review (NNSR) permitting requirements for any criteria pollutants.

Based on potential air emissions calculations, the Project will be subject to preconstruction review under the federal PSD permitting program, as potential emissions are greater than the 250 tons per year (tpy) major source threshold for multiple pollutants. The project results in a significant emissions increase and a significant net emissions increase of oxides of nitrogen (NO_X), carbon monoxide (CO), VOC, particulate matter (PM) with an aerodynamic diameter less than 10 microns (PM_{10}), PM with an aerodynamic diameter less than 2.5 microns ($PM_{2.5}$), and greenhouse gases (GHGs), represented as carbon dioxide equivalents (CO_2e).

1.2 Application Contents

In accordance with 40 CFR §52.21(n)(1), the following source information shall be submitted in an application for a project triggering PSD permitting:

i. A description of the nature, location, design capacity, and typical operating schedule of the source or modification, including specification and drawings showing its design and plant layout;

In addition to the description of the Project provided in Section 2 of this report, additional project details defining the characteristics, design capacity, and expected operating schedule for the equipment associated with the Project are provided in Section 3 of this report. Site maps and plot plans describing the Project are provided in Appendix A of this application. Application forms are included in Appendix B of this application.

ii. A detailed schedule for construction of the source of modification;

A proposed construction schedule is provided in Section 2.

iii. A detailed description as to what system of continuous emission reduction is planned for the source of modification, emission estimates, and any other information necessary to determine best available control technology would be applied;

Emissions estimates are described in Section 3 and detailed emissions calculations are provided in Appendix C of this application. An analysis of potentially applicable state and federal air regulations is provided in Section 4 and a case-by-case best available control technology (BACT) determination, meeting the requirements of 40 CFR §52.21(j), is detailed in Section 5. The following tables delineate a summary of the BACT determination following a "top-down" approach, as suggested by EPA:

[1] The DWP will be approximately 99 statute miles from where the pipe leaves the shore, also in Cameron Parish, Louisiana.

[2] 40 CFR §81.319

Table 1-1. Proposed VOC BACT Summary

Emission Source	Pollutant	Selected BACT	Emission / Operating Limit	Compliance Method
Marine Loading	VOC	VCU	Routine Operations: 99% Capture Efficiency; 95% Control Efficiency	Initial Test per 40 CFR § 63.563(b) and § 63.565(d)(2) of MACT Subpart Y, Continuous Compliance per § 63.564(e)
		Submerged fill	Maintenance Allowance	Per § 63.562(b)(6)(v) and (vi)
Natural Gas-Fired Engine-Driven Generator	VOC	Oxidation catalysts	0.3 g/hp-hr	Performance Testing Per Table 2 of Subpart JJJJ
Emergency Diesel-Fired Engine-Driven Generator	VOC	Good combustion practices	4.0 g/kW-hr of NMHC + NO_X	Certified engine; Maintenance records
Diesel-Fired Crane Engines	VOC	Good combustion practices	0.29 g/kW-hr	Certified engine; Maintenance records
Emergency Diesel-Fired Engine-Driven Firewater Pumps	VOC	Good combustion practices	3.0 g/hp-hr of NMHC + NO_X	Certified engine; Maintenance records
Fugitive Emissions	VOC	Component design; Good operating practices	Leak monitoring program	Leak monitoring records
Storage Vessels	VOC	Submerged fill	Installation of conforming tanks	Fixed roof tanks with submerged fill pipes

Table 1-2. Proposed CO BACT Summary

Emission Source	Pollutant	Selected BACT	Emission / Operating Limit	Compliance Method
Natural Gas-Fired Engine-Driven Generator	CO	Oxidation catalysts	0.23 g/hp-hr	Performance Testing Per Table 2 of Subpart JJJJ
Emergency Diesel-Fired Engine-Driven Generator	CO	Good combustion practices	3.5 g/kW-hr	Certified engine; Maintenance records
Diesel-Fired Crane Engines	CO	Good combustion practices	3.5 g/kW-hr	Certified engine; Maintenance records
Emergency Diesel-Fired Engine-Driven Firewater Pumps	CO	Good combustion practices	3.5 g/kW-hr	Certified engine; Maintenance records

Table 1-3. Proposed NO_X BACT Summary

Emission Source	Pollutant	Selected BACT	Emission / Operating Limit	Compliance Method
Natural Gas-Fired Engine-Driven Generator	NO_x	Good combustion practices	0.5 g/hp-hr	Performance Testing Per Table 2 of Subpart JJJJ
Emergency Diesel-Fired Engine-Driven Generator	NO_x	Good combustion practices	4.0 g/kW-hr of NMHC + NO_X	Certified engine; Maintenance records
Diesel-Fired Crane Engines	NO_x	Good combustion practices	0.6 g/kW-hr	Certified engine; Maintenance records
Emergency Diesel-Fired Engine-Driven Firewater Pumps	NO_x	Good combustion practices	4.0 g/kW-hr (3.0 g/bhp-hr) of NMHC + NO_X	Certified engine; Maintenance records

Table 1-4. Proposed $PM_{10}/PM_{2.5}$ BACT Summary

Emission Source	Pollutant	Selected BACT	Emission / Operating Limit	Compliance Method
Natural Gas-Fired Engine-Driven Generator	$PM_{10}/PM_{2.5}$	Use of pipeline-quality natural gas, good combustion practices	Work Practice	Maintenance records
Emergency Diesel-Fired Engine-Driven Generator	$PM_{10}/PM_{2.5}$	Use of ultra-low sulfur diesel, good combustion practices	0.2 g/kW-hr	Certified engine; Maintenance records
Diesel-Fired Crane Engines	$PM_{10}/PM_{2.5}$	Use of ultra-low sulfur diesel, good combustion practices	0.03 g/kW-hr	Certified engine; Maintenance records
Emergency Diesel-Fired Engine-Driven Firewater Pumps	$PM_{10}/PM_{2.5}$	Use of ultra-low sulfur diesel, good combustion practices	0.2 g/kW-hr (0.15 g/bhp-hr)	Certified engine; Maintenance records

Table 1-5. Proposed GHG BACT Summary

Emission Source	Pollutant	Selected BACT	Emission / Operating Limit	Compliance Method
Natural Gas-Fired Engine-Driven Generator	GHG	Use of natural gas, good combustion practices	12,871 tons CO_2e/yr, combined	Fuel consumption records
Emergency Diesel-Fired Engine-Driven Generator	GHG	Good combustion practices	Work Practice	Maintenance records
Diesel-Fired Crane Engines	GHG	Good combustion practices	Work Practice	Maintenance records
Emergency Diesel-Fired Engine-Driven Firewater Pumps	GHG	Good combustion practices	Work Practice	Maintenance records

Supporting documentation for the BACT evaluation is included as Appendix D of this application.

In accordance with 40 CFR §52.21(n)(2), the following information shall also be provided:

i. *The air quality impact of the source or modification, including meteorological and topographical data necessary to estimate such impact; and*

ii. *The air quality impacts, and the nature and extent of any or all general commercial, residential, industrial, and other growth which has occurred since August 7, 1977, in the area the source or modification would affect.*

The air quality impacts of the Project, as well as the source impact analysis required under 40 CFR §52.21(k) are addressed in Volume 2 of this PSD application.

2. PROJECT DESCRIPTION

The Applicant is proposing to develop the BMOP Project in the GOM to load crude oil into crude oil carriers for export to the global market.

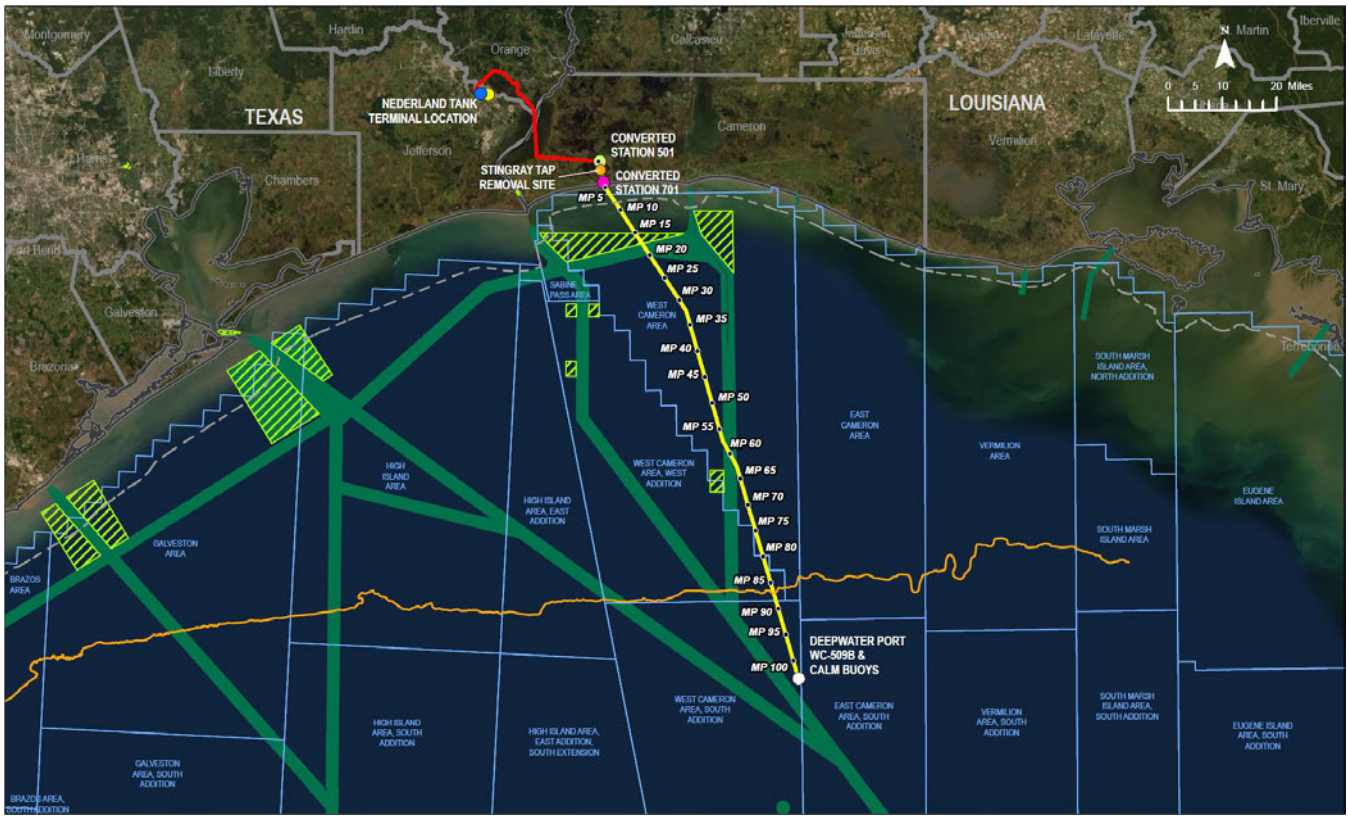
The primary purpose of the Project is to provide for safe and reliable long-term supply of crude oil for export to the global market. To fulfill the primary purpose, the Project must be capable of fully loading the international fleet of crude-carrying marine vessels to accommodate the safe and efficient transport of crude. Accordingly, the Project requires a DWP that can accommodate the draft and berth of a fully loaded VLCC with the ability to load in varying meteorological conditions. This ensures safety in transfer and transit by minimizing risks of transportation incidents (e.g., spills, allisions, collisions). It is not possible for existing onshore terminals in the GOM to fully load a VLCC due to limited draft. There are only a couple existing onshore terminals in the GOM that can partially load a VLCC; loading is completed offshore via reverse lightering. The proposed DWP design avoids the inefficiency and cost of idled time at a fixed port for partial VLCC loading while offering the benefit of avoiding dock-constrained ports to free up dock space for other commodities. This approach also resolves the logistical challenges and added vessel traffic of reverse lightering while mitigating the risks and additional environmental impacts of multiple loadings for a single fully-loaded VLCC.

2.1 Project Overview

The proposed Project utilizes many existing facilities, both onshore and offshore. Crude oil for export at BMOP will be transported out of the existing Energy Transfer Nederland Terminal, LLC terminal and storage facility in Jefferson County, Texas (Nederland Terminal or NT). This terminal is connected to multiple crude oil pipelines from across the U.S. In addition, an affiliate of the Applicant owns the Stingray Pipeline System (Stingray) and has confirmed that its existing subsea pipeline and offshore platforms are suitable for conversion to facilitate crude oil export from a DWP in the northern GOM.

Crude oil will be routed from the NT pump station through a new 42-inch outer diameter (OD) onshore pipeline to the existing Stingray Mainline at the existing Station 501, and from there through the existing 36" OD Stingray Mainline to the existing offshore platform complex at WC 509. The following figure presents a map of the Project. This figure is reproduced in Appendix A with additional detail.

Figure 2-1. Project Overview Map



The DWP will be located in federal waters within and adjacent to the OCS in WC 509, WC 508 and EC 263. The DWP will be approximately 82 statute miles off the coast of Cameron Parish, Louisiana, with an approximate water depth of 162 feet.[3] The crude oil will be metered at the pump station on the NT and on the existing WC 509B Platform and routed through two Crude Oil Loading Lines to PLEMs located on the seafloor below two CALM buoys located in WC 508 and in EC 263. From each PLEM, the crude oil will be routed to its respective floating CALM buoy through submerged flexible hoses. Crude oil carriers will moor at a CALM buoy, retrieve and connect the floating crude oil hoses connected to the CALM buoy and the crude oil will then route from the buoy to the crude oil carriers for loading. Up to 275 VLCCs will load per year.

The crude oils that will be exported range from light to heavy grade crudes and will be sent from the existing NT facility. The Project will accommodate loading up to 275 VLCCs with the use of two CALM buoys. Loading will not occur at both buoys simultaneously. During the time necessary for a loaded vessel to disconnect and depart the safety zone, and for a subsequent vessel to approach the same buoy, moor, and attach to the loading hoses, the second buoy will be loading a moored ship at up to 80,000 bbl/hr. The loading operation will then switch to the alternate buoy, providing the ability to continuously load one ship at a time. Displaced vapors during loading will be routed from the crude oil carrier to the CALM buoys through floating vapor return hoses. Submerged vapor hoses will carry the vapors from the buoys to the PLEM at the sea floor, where a looped subsea vapor return pipeline will route the vapors from the PLEMs to the VCUs at the WC 509 Platform Complex.

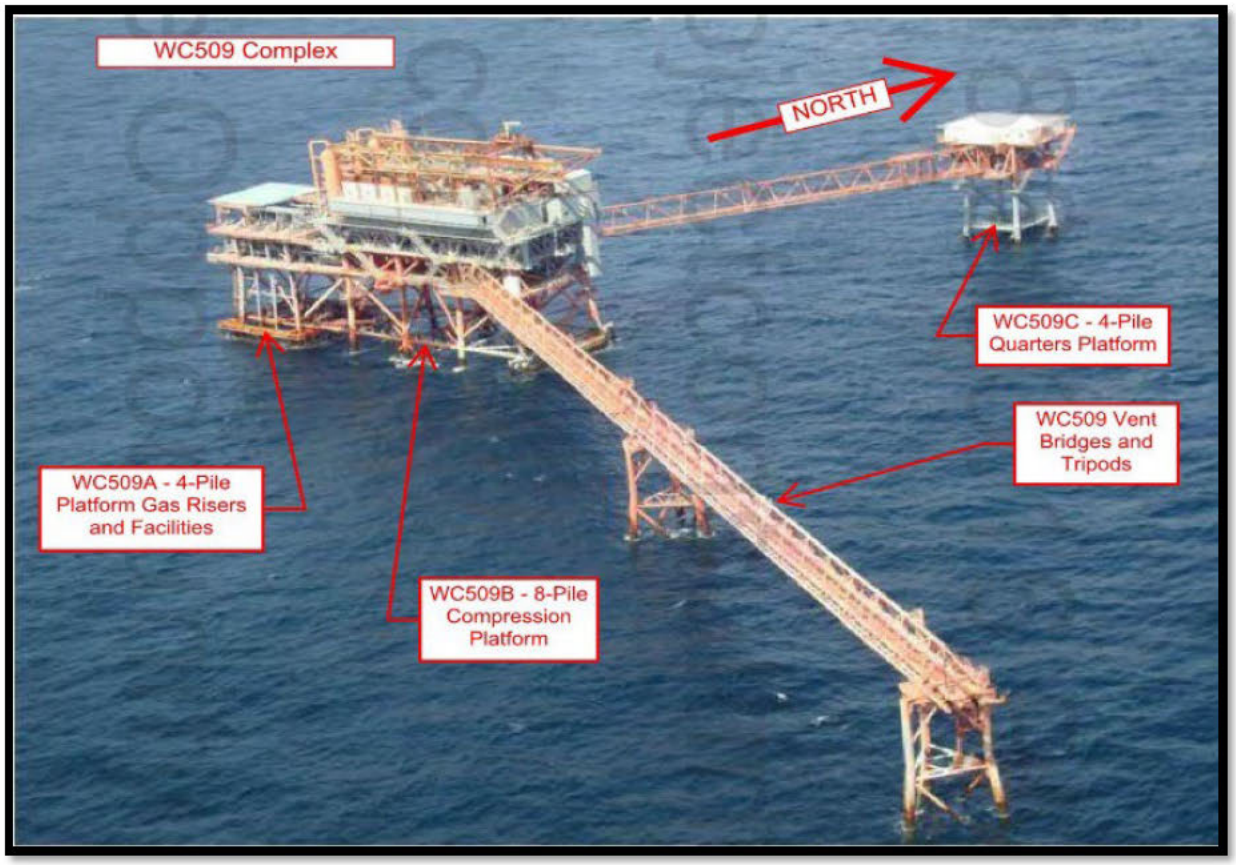
[3] The DWP will be approximately 99 statute miles from where the pipe leaves the shore, also in Cameron Parish, Louisiana.

This application is for the aggregated stationary sources subject to preconstruction permitting under PSD at the proposed offshore DWP. Site maps and plot plans at WC 509 are included in Appendix B to this application. The following subsections identify the stationary emissions sources.

2.1.1 Modified WC 509 Operations

Flow through the existing offshore Stingray Pipeline will be reversed to transfer crude oil from the existing Station 501 onshore to the existing WC 509 platform complex.

Figure 2-2. Existing WC 509 Platform Complex



This existing platform complex is near existing shipping channels currently used by large seafaring crude oil vessels with a water depth >160 feet. The natural gas lines currently on the WC 509A platform will be redirected subsea to the Sea Robin Pipeline system.

Following EPA's September 13, 2022, letter, BMOP has revised the Project design to include vapor capture and control with VCUs. The deck of the WC 509A platform will be stripped and raised, such that it can house dock safety units and three VCU stacks. With this design update, the Project will include added ability to access offshore natural gas supply currently routed through either the existing Stingray system to the WC 509A platform, or through a new connection to receive gas from the Sea Robin Pipeline system. Together, these gas supplies will serve basic platform utilities and vapor combustion assist gas without necessitating that all utilities be powered by fuel delivered from shore.

The Project will repurpose the WC 509B platform, removing all current equipment in natural gas service, and replacing it with support facilities for the crude oil DWP. The revised design will no longer retain any of the existing equipment – the existing natural gas compressors, four gas inlet scrubbers, piping and risers on 509A, and all other existing emissions units will be removed. To support the crude oil export operation, new components for oil service and other ancillary utility equipment will be installed at the WC 509 platform complex. The following new emission sources will be added at WC 509:

- Vapor controls
  - Three (3) vapor combustion units (VCUs);
  - One (1) low pressure flare for vapor line pigging operations at the Vent Bridge Tripod;
- One (1) high pressure flare for natural gas line pigging operations at the Vent Bridge Tripod;
- Fugitive Emissions from crude oil piping components;
  - New 36" OD risers;
  - Batch switching/pigging capability;
  - Crude oil meter and meter prover;
- Crude oil 1,000 barrel (bbl) capacity surge vessel and surge system;
- Fugitive Emissions from lube oil, waste oil, and sump collection systems;
- Ancillary utility equipment;
  - Two (2) redundant 1,736 kilowatt (kW) natural gas-fired engine-driven generators, Caterpillar G3516C, or similar;
  - One (1) 336 kW emergency diesel-fired engine-driven generator, Caterpillar 3512C, or similar;
    - Primary diesel fuel tank;
  - Two (2) 475 horsepower (hp) diesel-fired engine-driven cranes, Caterpillar G13, or similar;
    - Two (2) diesel fuel tanks (one for each crane);
  - Two (2) 650 hp emergency diesel-fired engine-driven firewater pumps, one on WC 509B and one on WC 509C; and
  - Helicopter re-fueling tank.

2.1.2 New Offshore Equipment for Marine Loading

From the existing WC 509 platform complex, new equipment will be added offshore to serve the DWP, including:

- **Two new CALM Buoys**
  - The CALM buoys will be anchored to the seafloor using a multiple-point, chain anchoring system capable of accommodating mooring forces exerted by a VLCC or other large seafaring vessel during loading operations. Each CALM buoy will have two 24-inch diameter floating hoses for vessel loading. Additionally, two floating vapor return hoses will be connected to the crude oil carrier's vapor system to capture displaced vapors, with the other end connected to a second swivel path on each CALM buoy. These floating hoses will be similar to the crude oil loading hoses, but for vapor return. All hoses will be approximately 1,500 feet long.
- **Two new PLEMs** connecting to each of the CALM buoys. One PLEM per buoy will transport crude oil from the seafloor up to the buoy through dual 24-inch undersea flexible hoses. The other PLEM transports returned vapors from the buoy down to the seafloor through dual 24-inch undersea flexible hoses.
- **Two lateral subsea Crude Oil Loading Pipelines** installed from the existing WC 509 Platform Complex to the PLEM locations, one for each PLEM. The Crude Oil Loading Pipelines to PLEM / CALM Buoy No. 1 and PLEM / CALM Buoy No. 2 will be 6,325 feet long and 6,085 feet long, respectively.
- **Four lateral subsea Vapor Return Pipelines** installed from the existing WC 509 Platform Complex to the PLEM locations, two for each PLEM in a loop for pigging. The Vapor Return Pipelines will transport

returned vapors from the PLEM at the seafloor to the WC 509 Platform Complex, where they are routed to the three (3) VCUs. The Vapor Return Pipelines to PLEM / CALM Buoy No. 1 and PLEM / CALM Buoy No. 2 will be 6,422 feet long and 6,085 feet long, respectively.

The location of the new equipment for marine loading in comparison to the existing WC 509 Platform Complex is delineated in the following table.

Table 2-1. DWP Components for Offshore Loading

Component	Latitude (N) (degrees minutes seconds)	Longitude (W) (degrees minutes seconds)	Water Depth (feet)
WC 509 Platform Complex[a]	28° 26' 00.01"	93° 00' 15.23"	162
CALM Buoy No. 1 and PLEM (WC 508)	28° 26′ 3.29″	93° 00′ 12.33″	162
CALM Buoy No. 2 and PLEM (EC 263)	28° 26′ 34.37″	92° 59′ 19.21″	159

a. Riser #1.

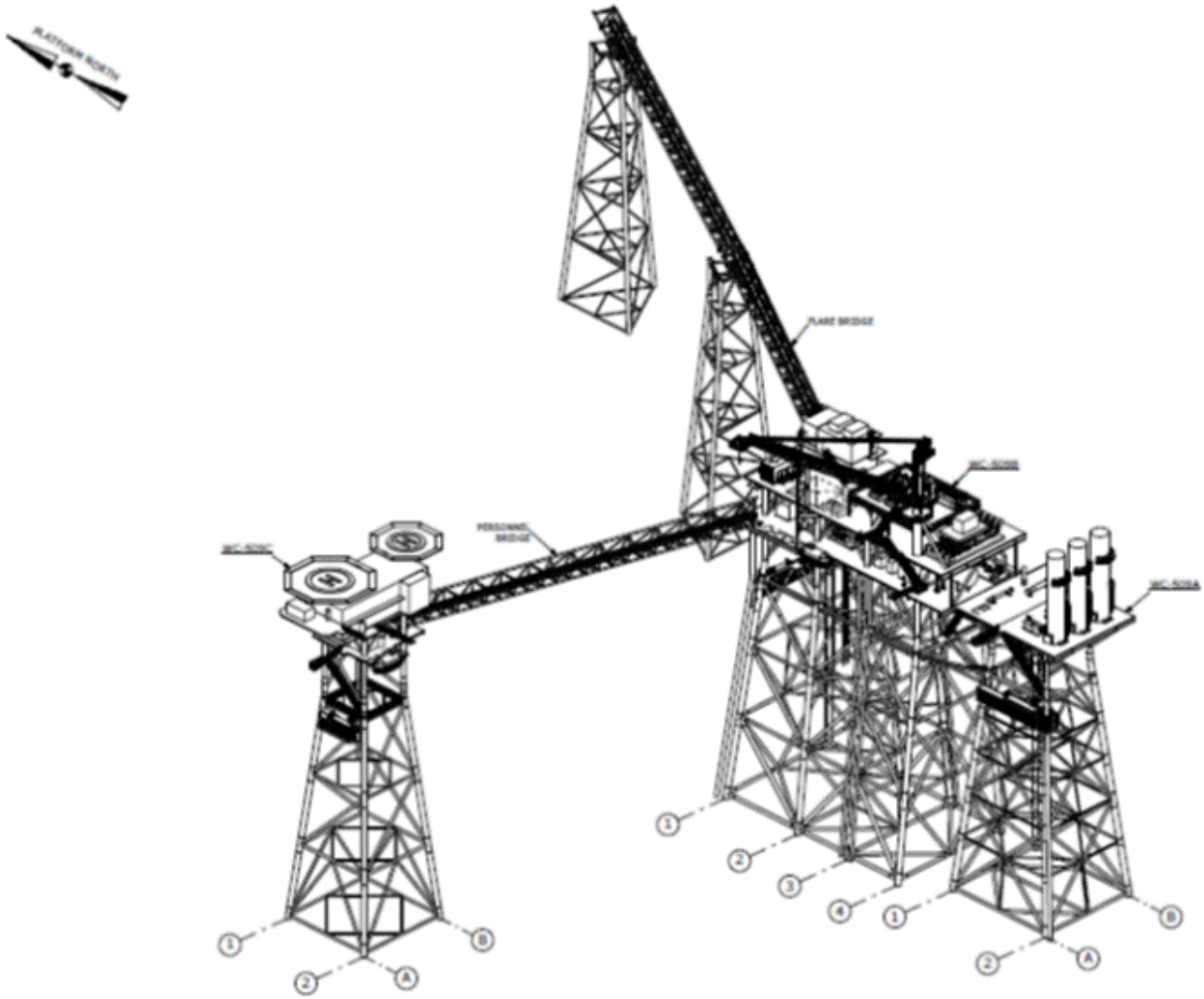
CALM Buoy No. 1 is 6,325 feet from its WC 509B riser, while CALM Buoy No. 2 is 6,085 feet from its WC 509B riser. Crude oil carriers will moor to the CALM buoys. As an SPM system, the vessels will be able to weathervane around the CALM buoy while moored and loading. No fixed structures or platforms will be located within ~ 1 mile of the buoy to allow safe vessel movement. This capability is an important design characteristic due to the DWP location of approximately 82 statute miles (71 nautical miles) from the nearest point on land. This location is classified as "exposed waters" by the United States Coast Guard (USCG), as it is greater than 20 nautical miles from the nearest harbor of safe refuge.[4] As well, the National Weather Service (NWS) provides distinct wind, wave, and weather forecasts for "offshore waters" greater than 60 nautical miles from shore, in comparison to "coastal water" forecasts inside of 60 nautical miles in the GOM.[5]

Floating and flexible 24-inch diameter hoses approximately 1,500 feet long will be installed for loading crude oil from the CALM buoy to the crude oil carrier, and returning vapor displaced during loading from the crude oil carrier to the CALM buoy. The floating crude oil hoses will be recovered by one of the DWP support vessels, lifted to the crude oil carrier loading manifold, and connected to the receiving flange. The floating vapor hoses will be lifted and connected to the crude oil carrier vapor system. The floating hoses will simply float on the surface of the water and will weathervane depending on the current when not being used for loading. The floating hoses will contain a butterfly valve on the end that will be utilized to isolate the hose after loading is complete and prior to placing the hoses back in the water. Additionally, a blind flange will be installed to further prevent any potential contamination or leakage while the hose is floating and waiting for the next crude oil carrier to be loaded.

[4] 46 CFR §170.050.

[5] https://www.nhc.noaa.gov/abouttafbprod.shtml

Figure 2-3. Schematic of the Proposed WC 509 Platform Complex



The schematic is presented again in Appendix A to this application.

The BMOP Project is unique from other sources and contemporary crude oil export operations because of its conversion of existing offshore facilities to support new CALM buoys in loading crude oil for export into an international fleet of crude oil carriers.

2.2 Proposed Schedule

Refurbishment of the existing WC 509 Platform Complex will begin in March 2024. The on-site installation of the crude oil subsea pipelines, PLEMs, and CALM buoy systems is expected to commence by 2025. Construction and commissioning are expected to complete in 4Q2026, with start up of the facilities occurring thereafter.

3. EMISSIONS QUANTIFICATION

3.1 Potential Emissions Summary

A summary of the potential emissions of NO_X, CO, VOC, sulfur dioxide (SO_2), PM_{10}, $PM_{2.5}$, hydrogen sulfide (H_2S), sulfuric acid mist (H_2SO_4), hazardous air pollutants (HAPs), and GHG represented as CO_2e is shown in Table 3-1.

Table 3-1. Potential Emissions Summary

	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	PM_{10}[6] (tpy)	$PM_{2.5}$ (tpy)	H_2S (tpy)	H_2SO_4 (tpy)	HAPs (tpy)	CO_2e (tpy)
Marine Loading										
Uncaptured Crude Oil Loading	--	--	1,604	--	--	--	0.70	--	89.9	--
VCU #1	143	263	260	4.25	4.99	4.99	0.11	--	14.6	157,510
VCU #2	143	263	260	4.25	4.99	4.99	0.11	--	14.6	157,510
VCU #3	143	263	260	4.25	4.99	4.99	0.11	--	14.6	157,510
Low Pressure Flare	4.03	8.05	52.9	0.32	--	--	--	--	2.96	4,815
Supporting Platform Operations										
Natural Gas High Pressure Flare	1.03	2.06	0.14	1.2E-3	--	--	--	--	0.013	886
Natural Gas Generators (x2)	11.2	5.17	6.29	0.05	0.80	0.80	--	2.3E-3	4.22	12,871
Emergency Diesel Generator	0.15	0.13	0.15	0.02	8.6E-3	8.6E-3	--	5.0E-4	6.1E-4	25.8
Platform B Cranes (x2)	2.05	11.97	0.97	1.48	0.21	0.21	--	0.05	0.06	2,383
Platform B Firewater Pump Engine	0.21	0.19	0.21	0.02	0.01	0.01	--	7.2E-4	3.6E-4	37.2
Platform C Firewater Pump Engine	0.21	0.19	0.21	0.02	0.01	0.01	--	7.2E-4	3.6E-4	37.2
Aviation Fuel Tank	--	--	5.1E-4	--	--	--	--	--	7.7E-5	--
Platform B Cranes Diesel Tank #1	--	--	1.9E-3	--	--	--	--	--	2.7E-4	--
Platform B Cranes Diesel Tank #2	--	--	1.9E-3	--	--	--	--	--	2.7E-4	--
Primary Diesel Tank	--	--	8.5E-3	--	--	--	--	--	1.2E-3	--
Surge Tank #1	--	--	3.73	--	--	--	--	--	0.07	--
Total Fugitive Emissions	--	--	23.7	--	--	--	5.1E-3	--	2.96	1,211
Total	**449**	**817**	**2,473**	**14.7**	**16.0**	**16.0**	**1.04**	**0.05**	**144**	**494,797**

[6] PM_{10} and $PM_{2.5}$ emissions are represented as the sum of filterable PM_{10}/$PM_{2.5}$ and condensable emissions.

3.2 Detailed Emissions Calculations

Potential emissions were calculated for the stationary offshore sources by using the following calculation methodologies.

3.2.1 Marine Loading

Emissions from marine loading occur as a result of displaced vapors from loading crude oil into a marine vessel. There are three emissions pathways as a result of the loading activity:

- Uncaptured loading vapors;
- Captured loading vapors controlled by a VCU; and
- Captured loading vapors that are routed to a low pressure flare during vapor pipeline pigging.

Each of these emissions pathways are addressed in this subsection, with the calculation methodology for characterizing the total vapor and the vapor constituents addressed first.

3.2.1.1 Marine Loading Vapors – VOC

VOC emissions from marine loading of crude oil are calculated based on the maximum hourly loading rate (gallons per hour [gal/hr]) and Equations 2 and 3 of EPA's AP-42, Section 5.2 (07/08), which was developed specifically for loading crude oil into ships and ocean barges,[7] and has also been utilized by EPA in the development of the National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart Y for onshore/near shore loading of crude oil.[8] The Project will load only crude oil, and no refined products. In addition to EPA's explicit direction in AP-42 to utilize Equations 2 and 3 for crude oil loading into ocean-going ships, this methodology is consistent with other marine loading of crude and permitting determinations in Louisiana,[9] which is the nearest onshore state. To align with the nearest state consistent with the DWP,[10] and based on Louisiana's recent determinations for crude loading into ships, Equations 2 and 3 are most appropriate to estimate emissions for the Project. Furthermore, BMOP has referenced footnote A of Table 5.2-3 in AP-42, which identifies that VOC emissions are 15% lower than the factor in the table, in consideration of the non-VOC loading vapors in the referenced arrival emissions factors for inerted marine vessel tanks.[11]

The application of Equations 2 and 3 is described below.

---

[7] AP-42 Chapter 5.2 Transportation and Marketing of Petroleum Liquids, 6/08.

[8] "*We agree with the commenter that the emission factors for ships and barges, as applicable to the type of marine vessel being loaded, should be considered for estimating VOC and HAP emissions. We have revised the emission estimates using the barge and ship emission factors from AP–42,"* referenced from 76 FR 22582, April 21, 2011, left column. Also see Subpart Y: Email from Michelle Herman, Chevron to Steve Shedd, EPA Chevron Pipe Line Nederland TX Emissions Data for MVL, 5/18/2010, ID: EPA-HQ-OAR-2010-0600-0044, which uses AP-42 Eq. 2 and 3 for crude oil loading into ships, and Eq. 1 for gasoline loading.

[9] See examples: Part 70 Permit No. 2520-00033-V-14 for International Matex Tank Terminals – IMTT – St. Rose, Louisiana, 8/14/2019, based on crude loading emissions from Eq. 2 and 3 from application for Title V Revision, dated June 3, 2019, and also Part 70 Permit No. 2560-00034-V9 for Sugarland Pipeline Station/Terminal, Shell Pipeline Company, LP, St. James, Louisiana, based on crude loading emissions from Eq. 2 and 3.

[10] 33 USC §1518(b).

[11] It should be noted that BMOP's crudes will be "weathered." This refinement considers the arrival emission factor (the characteristics of the vessel's tank vapors – which, in part, is related to the vessel's prior cargo).

$$C_L = C_A + C_G$$

Where:

$C_L = Total\ Loading\ Loss, pounds\ per\ 1000\ gallons\ \left(\frac{lb}{10^3 gal}\right) of\ crude\ oil\ loaded$

$C_A = Arrival\ emission\ factor, contributed\ by\ vapors\ in\ the\ empty\ tank\ compartment\ before\ loading, \frac{lb}{10^3 gal}\ of\ crude\ oil\ loaded$

$C_G = Generated\ emission\ factor, contributed\ by\ evaporation\ during\ loading, \frac{lb}{10^3 gal}\ of\ crude\ oil\ loaded$

Continuing to conservatively use the average arrival emission factor for an uncleaned ship/ocean barge tank, but following footnote A of AP-42 Table 5.2-3, C_A is determined to be:

$$C_A = TOC\ EF\ \left(\frac{lb}{10^3 gal}\right) \times (1 - nonVOC\ fraction) = 0.86 \times (1 - 0.15) = 0.731 \left(\frac{lb}{10^3 gal}\right)$$

The generated emissions factor, C_G is calculated based on Equation 3 of AP-42, Section 5.2, as described below.

$$C_G = 1.84 \times (0.44 \times P - 0.42) \times \frac{MG}{T}$$

Where:

$P = True\ vapor\ pressure\ of\ loaded\ crude\ oil, psia$

$M = Molecular\ weight\ of\ vapors, \frac{lb}{lb - mol}$

$G = Vapor\ growth\ factor, 1.02\ (dimensionless)$

$T = Temperature\ of\ vapors, °R$

BMOP estimates a maximum hourly loading rate of 80,000 barrels per hour (bbl/hr) of crude oil. [12] Note that with the implementation of vapor capture, it is not possible to sustain the maximum hourly loading rate for continuous loading every hour of the year. Accordingly, the maximum annual throughput is 605 million barrels per year (bbl/yr), based on the maximum annual loading schedule into marine vessels with vapor capture.

To calculate the VOC loading loss rate (in lb/10^3 gal), maximum hourly and annual average crude loading temperatures and crude true vapor pressures are used, based on Project design specifications. Because the crude oil will be subsea for approximately 100 nautical miles, the long-term temperature representative of the sea floor was used to estimate the loading temperatures.[13] The molecular weight of the crude oil (liquid and vapor) is based on AP-42, Chapter 7, Table 7.1-2 (06/20). A summary of the characteristics used to calculate VOC emissions is provided in Table 3-2.

3.2.1.2 Marine Loading Vapors – H_2S

Emissions of H_2S from marine loading are based on the hourly maximum and annual average H_2S content in the crude oil, and the following mass balance equation.

[12] 80,000 bbl/hr is approximately 3,360,000 gal/hr.

[13] Temperature data from ROMS Texas A&M University Outputs, Location: WC509, Depth 151 feet. Long-term average of 72.66°F used for annual average conditions and a maximum of 90°F used for short-term maximum conditions (max of dataset is 85.4°F.

$$H_2S\ Emission\ Rate\ \left(\frac{lb\ H_2S}{lb\ VOC}\right) = \frac{X}{1x10^6} \times \frac{M_{crude}}{M_{H2S}} \times \frac{M_{H2S}}{M_{Vapor}} \times k$$

Where:

$X = Crude\ H_2S\ Content, parts\ per\ million\ by\ weight\ (ppmw)$

$M_{crude} = Molecular\ weight\ of\ crude\ liquid, \left(\frac{lb}{lb-mol}\right)$

$M_{H_2S} = Molecular\ weight\ of\ H_2S, \left(\frac{lb}{lb-mol}\right)$

$M_{Vapor} = Molecular\ weight\ of\ crude\ vapor, \left(\frac{lb}{lb-mol}\right)$

$k = Vapor\ to\ liquid\ H_2S\ partition\ factor$[14]

A summary of the characteristics used to calculate H_2S emissions is also provided in the table below.

Table 3-2. Marine Loading Emissions Specifications

	Maximum Hourly	Annual Average
Crude Loading Rate (bbl/hr)	80,000	80,000
TOC Arrival Emission Factor	0.86	0.86
VOC Arrival Emission Factor	0.731	0.731
Loading Temperature (°R)	550	532
Vapor Molecular Weight (lb/lbmol)	50	50
Liquid Molecular Weight (lb/lbmol)	207	207
True Vapor Pressure [TVP] (psia)[15]	10.99	9.00
Liquid H_2S Partition	25	21
H_2S Concentration (ppmw)[16]	125	5
H_2S Molecular Weight (lb/lbmol)	34.1	34.1

3.2.1.3 Marine Loading Vapors – HAP

Emissions of HAP are based on an identified maximum crude oil vapor HAP speciation, by individual HAP, provided in weight percent (wt%) of the vapor. These maximum individual HAP concentrations were determined from thirteen samples of various crude types at the Nederland Terminal from May and June 2020 and analyzed per Method D7900, *Standard Test Method for Determination of Light Hydrocarbons in Stabilized Crude Oils by Gas Chromatography*.[17] The analytical results provided an extensive speciation of the crude oil, of which >99.9% was identified as VOCs. From these 13 samples, the average total HAP concentration in the liquid was 3.2 wt%. This identifies the expected average HAP concentration to be less than 5%, by weight, in the liquid.

[14] Per the Petroleum Processing Handbook, McGraw-Hill, New York, Figure 12-71, page 12-93.

[15] Maximum short-term and annual average true vapor pressure aligned with the permit limits for the origination of the crude oil for the BMOP Project – the Nederland Terminal. Note that the purpose of the project is to load a variety of both heavy and light crude oils, so using the permit limits is a conservative estimate of potential emissions for the Project.

[16] Hourly H_2S concentration aligned with permit limits for the origination of the crude oil for the BMOP Project – the Nederland Terminal. Annual mass H_2S emissions calculated from a conservative assumption of 5 ppmw. The average of all samples from Nederland (>3000 samples) is 1.31 ppmw.

[17] 49 CFR §171.7(h)(45).

For calculating potential emissions, the concentration in the vapor phase was calculated. Consistent with AP-42, Chapter 7.1.4 (06/2020), Raoult's Law was followed to determine the HAP content in the vapor phase of the crude oil from the HAP content in the liquid phase. Raoult's Law states that the mole fraction in the liquid of a speciated component, when multiplied by the vapor pressure of that component, is equal to the partial pressure of that component, or:

$$P_i = (P)(x_i)$$

Where:

$P_i = partial\ pressure\ of\ component\ i, psia$

$P = vapor\ pressure\ of\ pure\ component\ i\ at\ the\ average\ daily\ liquid\ surface\ temperature, psia$

$x_i = liquid\ mole\ fraction\ of\ component\ i, \frac{lb-mole}{lb-mole}$

The vapor pressure of each HAP species was determined using published Antoine Coefficients at the average daily temperature, described above.

The liquid mole fraction was determined from the liquid weight fraction of the component in the samples per:

$$x_i = \left(\frac{Z_{Li} M_L}{M_i}\right)$$

Where:

$x_i = liquid\ mole\ fraction\ of\ component\ i, \frac{lb-mole}{lb-mole}$

$Z_{Li} = weight\ fraction\ of\ component\ i\ in\ the\ liquid, lb/lb$

$M_L = molecular\ weight\ of\ liquid\ stock, \left(\frac{lb}{lb-mol}\right)$

$M_i = molecular\ weight\ of\ component\ i, \left(\frac{lb}{lb-mol}\right)$

The vapor mole fraction was determined by:

$$y_i = \frac{P_i}{P_{VA}}$$

Where:

$y_i = vapor\ mole\ fraction\ of\ component\ i, \frac{lb-mole}{lb-mole}$

$P_i = partial\ pressure\ of\ component\ i, psia$

$P_{VA} = total\ vapor\ pressure\ of\ liquid\ mixture, psia$

The weight fractions in the vapor phase can then be determined from the mole fractions in the vapor phase.

$$Z_{Vi} = \frac{y_i M_i}{M_V}$$

Where:

$Z_{Vi} = vapor\ weight\ fraction\ of\ component\ i, lb/lb$

$y_i = vapor\ mole\ fraction\ of\ component\ i, \frac{lb-mole}{lb-mole}$

$M_i = molecular\ weight\ of\ component\ i, \left(\frac{lb}{lb-mol}\right)$
$M_V = molecular\ weight\ of\ vapor\ stock, \left(\frac{lb}{lb-mol}\right)$

The resulting total HAP in the vapor averaged 2.4% for all 13 samples.

In order to ensure a conservative representation of potential emissions on a short-term basis, the 99% upper prediction limit (UPL) was calculated for each individual HAP identified in the 13 samples. The UPL is a value derived from widely accepted and commonly used statistical principles and represents the upper end of a prediction interval.[18] EPA notes that the UPL is a statistical methodology used "as the primary tool to account for emissions variability when setting emissions standards." The UPL calculates the average emissions limitation achieved over time by the best performing source. [19]

> *In the context of development of MACT floors, the UPL is a value, calculated from a dataset, that identifies the average emissions level that a source or group of sources is meeting and would be expected to meet a specified percent of the time that the source is operating.*
>
> *In other words, the 99 percent UPL is the level of emissions that we are 99 percent confident is achieved by the average source represented in a dataset over a long-term period based on its previous, measured performance history as reflected in short term stack test data.*
>
> *In sum, the UPL predicts the level of emissions that the sources upon which the floor is based are expected to meet over time, considering both the average emissions level achieved as well as emissions variability and the uncertainty that exists in the determination of emissions variability given the available, short-term data.*

Following EPA's preferred approach to determining a standard that can be met by a unit with emissions at the average level of the best performing source, BMOP has completed the calculation of the 99 percent UPL value for each individual HAP identified from the 13 crude oil samples. The following equation presents the approach to the UPL calculations for a dataset with a lognormal distribution (Equation 2 from *EPA's Response to Remand of the Record for Major Source Boilers, July 14, 2014*).

$$UPL_{100-(\alpha\times100)} = e^{\hat{\mu}+\frac{\hat{\sigma}^2}{2}} + \frac{z_{(1-\alpha)}}{m}\sqrt{me^{2\hat{\mu}+\hat{\sigma}^2}\left(e^{\hat{\sigma}^2}-1\right) + m^2e^{2\hat{\mu}+\hat{\sigma}^2}\left(\frac{\hat{\sigma}^2}{n} + \frac{\hat{\sigma}^4}{2(n-1)}\right)}$$

Where: α = level of significance expressed as a decimal (e.g., 1% significance = 0.01); note that confidence level $= 100 - (\alpha \times 100)$;
e = base of the natural logarithm ≈ 2.718282;
$\hat{\mu}$ = mean of the log transformed sample data $\left(= \frac{1}{n}\sum_{i=1}^{n} \ln\,(x)_i\right)$;
$\hat{\sigma}^2$ = variance of the log transformed sample data $\left(= \frac{1}{n}\sum_{i=1}^{n} (\ln(x)_i - \hat{\mu})^2\right)$;
z = z score, the one-tailed z value of the z distribution for a specific level of significance;

[18] National Institute of Standards and Technology, *NIST/SEMATECH e-Handbook of Statistical Methods*, <http://www.itl.nist.gov/div898/software/dataplot/refman1/auxillar/predlimi.htm>.

[19] Memorandum from Stephen D. Page, Director, Office of Air Quality Planning and Standards, U.S. EPA, to Docket ID No. EPA-HQ-OAR-2002-0058, "EPA's Response to Remand of the Record for Major Source Boilers," July 14, 2014.

m = number of sample values used to calculate the average;
n = number of samples.

The results of the UPL of the HAP mass percent in the liquid crude are presented in the following table.

Table 3-3. Summary of UPL by HAP, Liquid Mass Percent

HAP	99% UPL (wt. %, liquid)
Hexane	3.09
Benzene	0.46
Toluene	1.10
Ethylbenzene	0.29
1,2,4-Trimethylbenzene	0.76
1,3—Dimethylbenzene	0.79
1,4-Dimethylbenzene	0.57
1,2-Dimethylbenzene	0.37
Cumene	0.08
Total HAP	**7.50**

The liquid mass percent was converted to the mass percent in vapor, based on the calculated vapor speciation using the extended results of the 13 samples and Raoult's Law. The calculation of vapor pressure utilized Antoine's equation, referenced at equation 1-26 of AP-42, Chapter 7.1 (06/2020), and Antoine's constants determined for each species at a temperature of 72.66 °F. The 99% UPL was then determined for the vapor mass percent, as shown in the table below.

Table 3-4. Summary of UPL by HAP, Vapor Mass Percent

HAP	99% UPL (wt. %, vapor)
Hexane	4.09
Benzene	0.34
Toluene	0.29
Ethylbenzene	0.02
1,2,4-Trimethylbenzene	0.01
1,3—Dimethylbenzene	0.05
1,4-Dimethylbenzene	0.03
1,2-Dimethylbenzene	0.02
Cumene	0.003
Total HAP	**4.86**

BMOP used the higher of the 99% UPL vapor weight percent from the 13 samples, or the Nederland Terminal Permit basis for each individual HAP, whichever was greater. The result is a conservative estimate for each individual HAP and the total HAP (which is the sum of the highest values for each individual HAP).

BMOP has used the following crude oil vapor HAP speciation to estimate emissions.

Table 3-5. Crude Oil Vapor HAP Speciation

HAP	Vapor Weight %
Hexane	4.09
Benzene	0.80
Toluene	0.36
Ethylbenzene	0.05
1,2,4-Trimethylbenzene	0.01
1,3-dimethylbenzene	0.05
1,4-dimethylbenzene	0.03
1,2-dimethylbenzene (Xylene)	0.21
i-propylbenzene (Cumene)	0.01
Biphenyl	0.00002
Cresols	0.001
Naphthalene	0.001
Phenol	0.001
Total HAP	5.60

Hourly and annual VOC emissions are multiplied by each HAP speciation, above, to determine the hourly and annual HAP mass emission rates.

3.2.1.4 Marine Loading Vapors – GHG

None of the 13 samples of varying crude types identified methane (CH_4) or carbon dioxide (CO_2) in the crude. Although produced crude may have some amount of methane, methane is highly volatile and will quickly be released in vapor prior to being loaded into a marine vessel in the BMOP DWP, after many steps of production (which is initially extracted at pressure, then stored in atmospheric tanks where the majority of light ends flash off), processing, storage, and hundreds of miles of transmission. Referred to as "weathering," it is typical for the lightest volatile compounds, including methane and carbon dioxide, to be released well before reaching a storage terminal. This is evident in that none of the 13 samples contained even a small fraction of methane or carbon dioxide in the crude at the Nederland Terminal.

Accordingly, GHG emissions from crude oil loading at the BMOP project are not expected.

3.2.2 Marine Loading – Uncaptured Emissions

This submittal reflects the new Project design, including capture and control of vapors from marine loading. BMOP expects the vapor capture system collection efficiency to be 99% during routine operations. Accordingly, 1% of routine marine loading results in uncaptured emissions.

In addition, 40 CFR 63 Subpart Y provides a "maintenance allowance," or a period of time that the DWP is allowed to perform maintenance on the loading berth without controlling emissions from marine tank vessel

loading operations.[20] BMOP has estimated an annual maintenance allowance of 629 hours, as presented in more detail in Section 4.2.1.2.4 of this application. During these 629 hours, it is assumed that all loading emissions from submerged fill operations will be uncaptured at the annual average emissions rate.

Table 3-6. Potential VOC and HAP Mass Emissions from Uncaptured Marine Loading

Pollutant	Max Hourly Loading Vapors (lb/hr)	Uncaptured Annual Emissions (tpy)
VOC	4,989	1,604
HAP speciation:		
Hexane	204.0	65.6
Benzene	39.93	12.8
Toluene	17.73	5.70
Ethylbenzene	2.48	0.80
1,2,4-Trimethylbenzene	0.53	0.17
1,3-dimethylbenzene	2.38	0.76
1,4-dimethylbenzene	1.66	0.53
1,2-dimethylbenzene (Xylene)	10.36	3.33
i-propylbenzene (Cumene)	0.29	0.09
Biphenyl	0.001	0.0003
Cresols	0.04	0.012
Naphthalene	0.03	0.010
Phenol	0.07	0.024
Total HAP	279.5	89.9

3.2.3 Marine Loading – Controlled Emissions by Vapor Combustion Units

The Project will operate three (3) vapor combustion units (VCUs) to control the captured vapor emissions from marine vessel loading operations. BMOP predicts that each VCU will have a destruction and removal efficiency (DRE) of 95% during routine operations.

NO_x and CO emissions are calculated based on the emission factor estimated by the VCU vendor. Filterable and condensable PM emissions are estimated based on emissions factors from AP-42 Chapter 1, Table 1.4-2 (07/98), *Emissions Factors for Natural Gas Combustion*. Filterable PM emissions are assumed to be equivalent to PM_{10} and $PM_{2.5}$ emissions. SO_2 and H_2S emissions are based on an annual average H_2S concentration of 5 ppmw from crude oil compositions provided by BMOP. It is assumed that 95% of the H_2S is combusted, and 100% of the combusted H_2S is oxidized to form SO_2. VOC and HAP emissions are also based on the crude oil compositions, discussed previously for marine loading vapor composition, and the predicted DRE of 95% (of the 99% captured vapors, less the maintenance allowance). GHG emissions of CO_2, CH_4, and N_2O are based on emission factors provided in 40 CFR 98, Subpart C, Tables C-1 and C-2, for

[20] Definition of "maintenance allowance" per 40 CFR 63.561.

"various types of fuel". The CO_2e emission rate was calculated based on the CO_2, CH_4, and N_2O GWP's of 1, 25, and 298, respectively.

To calculate emissions for heat rate based emission factors (lb/MMBtu or kg/MMBtu), a crude oil vapor HHV of 1,456 MMBtu/MMscf and VCU maximum heat input rate of 218 MMBtu/hr were used. These values were derived from crude oil specifications at 100% vessel loading by BMOP, which represents a short-term maximum. The average heat input rate of an entire vessel is expected to be lower.

To conservatively estimate emissions from the VCU stacks, BMOP assumes that each VCU will operate continuously at 100% loading.

3.2.4 Marine Loading – Controlled Emissions by Low Pressure Flare

The Project will operate one (1) low pressure flare to be utilized to control routine pigging of the crude oil carrier vapor lines following marine vessel loading. BMOP predicts that the low pressure flare will receive vapor at a rate of 3.5 MMscf/day.

NO_x and CO emissions estimated for high Btu gas stream combustion in flares that are not steam assisted. VOC and HAP emissions are found using the crude oil vapor composition from 13 crude oil samples, an assumption that all vapors are VOC, and a flare DRE of 98%. SO_2 emissions are also found from the H_2S content in the provided crude oil vapor composition. It is assumed that 100% of the H_2S in the vapor is oxidized to form SO_2. GHG emissions of CO_2, CH_4, and N_2O from vapor combustion are based on emission factors provided in 40 CFR 98, Subpart C, Tables C-1 and C-2, for "various types of fuel". The CO_2e emission rate was calculated based on the CO_2, CH_4, and N_2O GWP's of 1, 25, and 298, respectively.

Based on current project design specifications, the low pressure flare is operated in a 1-hour period following loading of each vessel. Up to 275 VLCCs are loaded at the WC 509 Platform per year. Thus, emissions from the low pressure flare are based on an annual operating time of 275 hours.

3.3 WC 509 Platform Support Equipment Emissions

The following subsections describe the emissions calculation methodology for equipment on the WC509 Platform Complex that supports the proposed DWP.

3.3.1 Natural Gas Generators

The Project will operate two (2) natural gas-fired generators. BMOP design identifies that the make/model of each generator will be similar to a Caterpillar G3516C, each rated at approximately 2,000 hp. To conservatively estimate emissions from the proposed units, a maximum power of 2,328 hp was used, per the manufacturer's specifications sheet at 100% load.

Emissions from NO_X, CO, and VOC are based on the vendor expected emissions for a Caterpillar G3516C engine with an oxidation catalyst, in grams per horsepower-hour (g/hp-hr). Emissions from formaldehyde are limited to 14 ppmvd or less at 15% O_2, based on Table 2a of NESHAP Subpart ZZZZ.[21] Emissions from CO_2 and CH_4 are estimated based on the manufacturer's specifications sheet, in grams per kilowatt hour (g/kW-hr). Emissions from filterable PM_{10}, $PM_{2.5}$, condensable PM, SO_2, and the remaining HAPs are estimated based on emission factors from AP-42 Chapter 3, Table 3.2-2 (07/00), *Uncontrolled Emission Factors for 4-Stroke Lean Burn Engines*, in pounds per million British thermal units (lb/MMBtu). Filterable

[21] Table 2a of NESHAP Subpart ZZZZ for four-stroke lean burn (4SLB) stationary RICE.

PM emissions are assumed to be equivalent to filterable PM_{10} and $PM_{2.5}$ emissions. H_2SO_4 emissions are assumed to be 5% of SO_2 emissions. The natural gas specific emission factor from 40 CFR 98 Subpart C, Table C-2, *Default CH_4 and N_2O Emission Factors for Various Types of Fuel,* is used to estimate N_2O emissions, in kilograms per MMBtu (kg/MMBtu). The CO_2e emission rate is calculated based on the CO_2, CH_4, and N_2O emission rates, weighted according to their global warming potentials (GWP) of 1, 25, and 298, respectively.

To calculate emissions for heat rate based emission factors (lb/MMBtu or kg/MMBtu), a natural gas higher heating value (HHV) of 1,020 British thermal units per standard cubic foot (Btu/scf)[22] and average brake-specific fuel consumption rate of 17,820 scf per hour (scf/hr) are used.[23]

Based on the current Project design, only one engine will be operating at any given time to continuously power the sources of the DWP platform. Therefore, potential annual emissions are based on the continuous operation of a single engine at 100% load.

3.3.2 High Pressure Flare

The Project will operate one (1) high pressure flare to be utilized during periodic pigging of the natural gas line to the WC 509 Platform. BMOP predicts that the high pressure flare will receive natural gas at a rate of 32 MMscf/day, and conservatively estimates 1 event per year.

NO_x and CO emissions estimated for high Btu gas stream combustion in flares that are not steam assisted. VOC, HAP, and uncombusted CH_4 emissions are found using the Stingray system natural gas composition and a flare DRE of 98%. SO_2 emissions are also found from the H_2S content in the provided natural gas composition. It is assumed that 100% of the H_2S in the natural gas is oxidized to form SO_2. GHG emissions of CO_2, CH_4, and N_2O from natural gas combustion are based on emission factors provided in 40 CFR 98, Subpart C, Tables C-1 and C-2, for natural gas. The CO_2e emission rate is calculated based on the CO_2, CH_4, and N_2O GWP's of 1, 25, and 298, respectively.

Based on current project design specifications, the high pressure flare is only operated during natural gas line pigging. Each pigging event lasts around 11 hours. Pigging is expected to occur once per 7 years but is conservatively assumed to occur once per year in the emissions calculations.

3.3.3 Emergency Diesel Generator

The Project will operate one (1) emergency, diesel-fired generator. BMOP design identifies that the emergency generator will be rated at approximately 336 kW (~450 hp).

Emissions from filterable PM, NO_X, VOC, and CO are estimated based on the emissions standards provided in 40 CFR §60.4202(a)(2) and Table 3 of Appendix I to 40 CFR 1039, in g/kW-hr.[24] Filterable PM emissions are assumed to be equivalent to PM_{10} and $PM_{2.5}$ emissions. HAP emissions are estimated based on emission factors from AP-42 Chapter 3, Tables 3.3-1 and 2 (10/96), *Emission Factors for Uncontrolled Gasoline and*

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[22] Per footnote b of AP-42, Table 3.2-2.

[23] Per the manufacturer's specification sheet at 100% load.

[24] Per 40 CFR §60.4202(a)(2), for 2007 model year or later emergency stationary compression ignition internal combustion engines with a rated power greater than or equal to 50 hp, less than 3,000 hp, with a displacement less than 10 liters per cylinder, and that are not fire pump engines. It is conservatively assumed that NO_X and VOC emissions are equivalent to the NMHC+NO_X emission limit.

Diesel Industrial Engines, in lb/MMBtu. AP-42 Chapter 3.3 does not provide an emission factor for condensable PM, therefore, the condensable PM emission factor provided in AP-42, Table 3.4-2, *Emission Factors for Large Uncontrolled Stationary Diesel Engines,* is conservatively used. SO_2 and H_2SO_4 emissions are based on a diesel fuel sulfur content of 0.1%. It is estimated that 98% of the sulfur is oxidized to SO_2 and the remaining 2% is hydrolyzed to H_2SO_4. GHG emissions of CO_2, CH_4, and N_2O are based on emission factors provided in 40 CFR §98, Subpart C, Tables C-1 and C-2, for distillate fuel oil No. 2. The CO_2e emission rate is calculated based on the CO_2, CH_4, and N_2O GWP's of 1, 25, and 298, respectively.

To calculate emissions for heat rate based emission factors (lb/MMBtu or kg/MMBtu), a distillate fuel oil HHV of 19,300 British thermal units per pound (Btu/lb) and average brake-specific fuel consumption (BSFC) rate of 7,000 British thermal units per horsepower-hour (Btu/hp-hr) are used. [25]

The emergency diesel-fired generator will only operate during periods where both natural gas generators are unavailable or for maintenance and readiness testing. Therefore, to estimate potential emissions, BMOP conservatively assumes that the emergency generator will not operate more than 100 hours per year, operating at 100% load.

3.3.4 Platform Crane Engines

The Project will operate a number of platform cranes for various types of operation. Based on current design specifications for the Project, the following diesel-fired crane engines will be located at the WC 509 platform complex:

- Two (2) 354 kW (~475 hp) diesel engines.

Emissions from filterable PM, NO_X, CO, and VOC are estimated based on the emissions standards provided in 40 CFR §60.4204(b), in g/kW-hr.[26] To conservatively estimate emissions from the crane engines, emissions of PM, NO_X, and VOC are multiplied by the appropriate Not to Exceed (NTE) multiplier provided in 40 CFR §1039.101(e), which, for engines with a NO_X standard less than 2.5 g/kW-hr and PM standard less than 0.07 g/kW-hr is 1.5. Filterable PM emissions are assumed to be equivalent to PM_{10} and $PM_{2.5}$ emissions.

Emissions from HAPs are estimated based on emission factors from AP-42 Chapter 3, Tables 3.3-1 and 2 (10/96), *Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines*. AP-42 Chapter 3.3 does not provide an emission factor for condensable PM, therefore, the condensable PM emission factor provided in AP-42, Table 3.4-2, *Emission Factors for Large Uncontrolled Stationary Diesel Engines,* is conservatively used. SO_2 and H_2SO_4 emissions are based on a diesel fuel sulfur content of 0.1%. It is estimated that 98% of the sulfur is oxidized to SO_2 and the remaining 2% is hydrolyzed to H_2SO_4. GHG emissions of CO_2, CH_4, and N_2O are based on emission factors provided in 40 CFR §98, Subpart C, Tables C-1 and C-2, for distillate fuel oil No. 2. The CO_2e emission rate is calculated based on the CO_2, CH_4, and N_2O GWP's of 1, 25, and 298, respectively.

To calculate emissions for heat rate based emission factors (lb/MMBtu or kg/MMBtu), a distillate fuel oil HHV of 19,300 Btu/lb and average BSFC rate of 7,000 Btu/hp-hr are used. [27]

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[25] Per footnote e of AP-42 Table 3.4-1.

[26] Per 40 CFR §60.4204(b) and 40 CFR §1039.101, for 2014 model year or later combustion ignition internal combustion engines between 130 kW to 560 kW.

[27] Per footnote c of AP-42 Table 3.3-1.

To conservatively estimate emissions from the crane engines, BMOP assumes that each crane engine will operate up to 4,380 hours per year.

3.3.5 Firewater Pump Engines

The Project will operate two (2) firewater pump engines. Current design specifications for the Project identify that the engines will be rated at approximately 485 kW (~650 hp).

Emissions from filterable PM, NO_X, CO, and VOC are estimated based on the emissions standards provided in Table 4 of NSPS Subpart IIII[28] and 40 CFR §60.4204(b), in g/kW-hr.[29] Filterable PM emissions are assumed to be equivalent to PM_{10} and $PM_{2.5}$ emissions.

Emissions from HAPs are estimated based on emission factors from AP-42 Chapter 3, Tables 3.3-1 and 2 (10/96), *Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines*. AP-42 Chapter 3.3 does not provide an emission factor for condensable PM, therefore, the condensable PM emission factor provided in AP-42, Table 3.4-2, *Emission Factors for Large Uncontrolled Stationary Diesel Engines,* is conservatively used. SO_2 and H_2SO_4 emissions are based on a diesel fuel sulfur content of 0.1%. It is estimated that 98% of the sulfur is oxidized to SO_2 and the remaining 2% is hydrolyzed to H_2SO_4. GHG emissions of CO_2, CH_4, and N_2O are based on emission factors provided in 40 CFR §98, Subpart C, Tables C-1 and C-2, for distillate fuel oil No. 2. The CO_2e emission rate is calculated based on the CO_2, CH_4, and N_2O GWP's of 1, 25, and 298, respectively.

To calculate emissions for heat rate based emission factors (lb/MMBtu or kg/MMBtu), a distillate fuel oil HHV of 19,300 Btu/lb and average BSFC rate of 7,000 Btu/hp-hr are used. [30]

The emergency firewater pump engines will only operate during periodic maintenance testing and during emergencies. Therefore, to estimate potential emissions, BMOP conservatively assumes that the firewater pump engines will not operate more than 100 hours per year, operating at 100% load.

3.3.6 Storage Tanks

The Project will operate various fuel and petroleum liquid storage tanks. Current design specifications for the Project predict that the following storage tanks will be located at each platform:

- Platform B
  - Two (2) 4,400 gallon diesel storage tanks associated with each platform crane.
  - One (1) 18,000 gallon primary diesel storage tank.
  - One (1) 42,000 gallon crude oil surge tank.
- Platform C
  - One (1) 3,000 gallon aviation fuel (estimated as jet kerosene) tank.

[28] Per 40 CFR §60.4205(c) for firewater pump engines with a displacement of less than 30 liters/cylinder between 225 kW and 450 kW. Conservatively assume that NO_X and VOC emissions are equivalent to the NMHC+NO_X emissions limit.

[29] Per 40 CFR §60.4204(b) and 40 CFR §1039.101, for 2014 model year or later combustion ignition internal combustion engines between 130 kW to 560 kW.

[30] Per footnote c of AP-42 Table 3.3-1.

TankESP™ software was utilized to estimate potential annual emissions consistent with the methodology of AP-42 Chapter 7.1 using the following dimensions and usage assumptions.

Table 3-7. Storage Tank Representation

Tank	Tank Dimensions				Volume (gal)	Max. Filling Rate (gal/hr)	Annual Throughput (gal/yr)	Orientation
	L (ft)	W (ft)	H (ft)	Dia. (ft)				
Crane Diesel Storage Tank #1	--	--	30	5	4,400	400	114,400	Vertical
Crane Diesel Storage Tank #2	--	--	30	5	4,400	400	114,400	Vertical
Primary Diesel Storage Tank	16	15.48	16	--	18,000	400	468,000	Horizontal
Crude Oil Surge Tank	47.5	12.67	47.5	--	42,000	80,000	42,000	Horizontal
Aviation Fuel Tank	10	--	--	6.67	3,000	200	13,000	Horizontal

The chemical characteristics for jet kerosene and diesel fuel were based on standard TankESP™ defaults, while the chemical characteristics for crude oil were based on the same annual average values as described for loading emissions, provided in Table 3-2 above. It was assumed that all tanks will have fixed roofs and will be operated continuously.

3.3.7 Fugitive Emissions

Fugitive emissions were calculated based on the synthetic organic chemical manufacturing industry (SOCMI) average emission factor (in pounds per hour [lb/hr])[31], using the following equation.

$$E_{VOC} = F_A \times WF_{VOC} \times N$$

Where:

$E_{VOC} = Emission\ rate\ of\ VOC\ from\ all\ equipment\ in\ the\ stream, \frac{lb}{hr}$

$F_A = SOCMI\ average\ emission\ factor, \frac{lb}{hr}$

$WF_{VOC} = Weight\ fraction\ of\ VOC\ in\ the\ stream, \%$

$N = number\ of\ components\ in\ the\ stream$

This factor was chosen to ensure a conservative representation of the collection of piping components in various services (i.e. crude oil, diesel, natural gas, vapor etc) at the WC 509 DWP. It should be noted that no reduction from these average emissions factors has been applied for these estimates, to ensure a conservative representation. Actual emissions will be much lower, as piping components will be monitored and repaired, if found to be leaking, based on the applicable leak detection and monitoring requirements.

The total number of piping components for each applicable stream are based on current design estimates for the Project. The different streams are categorized as gas/vapor or light liquid service based on the contents of the stream. The total number of components are then multiplied by the appropriate SOCMI emission factor. For piping components servicing natural gas streams, it is assumed that the components

[31] As provided in EPA's Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017 https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf

are in gas/vapor service. For piping components servicing diesel fuel, crude oil, or aviation fuel (assumed to be equivalent to jet kerosene), it is assumed that the components are in light liquid service.

To determine the VOC emission rate, the stream is multiplied by the VOC wt% of the stream. For components in natural gas service, the total VOC composition of the stream is based on an April 13, 2020 sample at the DWP platform. For components in diesel fuel or jet kerosene service, the total VOC composition is consistent with the TankESP™ defaults. For components in crude oil service, the total VOC composition is based on the maximum vapor wt% used for crude oil loading emissions calculations.

Similar to VOC emissions, HAP emissions for the fugitive components were calculated using the same approach as above. Fugitive emissions also consider H_2S emissions from components in crude oil service and GHG emissions from components in natural gas service, using the same methodology as above. Annual emissions for all fugitive components are based on continuous operation (i.e. 8,760 hours of operation).

3.3.8 Maintenance, Startup, and Shutdown

BMOP has evaluated potential emissions not already identified above that may occur during maintenance, startup, and shutdown (MSS). In accordance with 40 CFR § 3.562(b)(6) of NESHAP Subpart Y, BMOP is applying for a "maintenance allowance" of 629 hours, annually that the DWP may perform maintenance on the loading berths without controlling emissions from marine tank vessel loading operations. During the maintenance allowance, the displaced vapors from crude oil loading activities would exhaust through the crude oil carrier's vent mast riser. The emissions during the maintenance allowance have been addressed previously and included in the annual potential emissions represented for uncaptured emissions from marine loading.

The existing WC 509 platform complex includes a vent boom for natural gas blowdowns. Following the repurposing of the platform complex from natural gas service to crude oil service, the vent boom will be updated to include a high pressure flare (emissions previously addressed). Similarly, routine pigging of the vessel loading vapor return lines will be routed to a low pressure flare (emissions previously addressed).

The Project includes pig launchers and receivers on WC 509B for the crude oil pipeline. During maintenance activities requiring pigging, BMOP will utilize marine vessels for collection of the liquid pushed by the pigs. BMOP will follow the same Best Management Practices (BMP) as marine vessel loading and identify records as "maintenance." Because potential VOC and HAP emissions have been calculated based on continuous loading, emissions from loading losses as a result of pigging are already included in the potential emissions estimates above.

4. REGULATORY ANALYSIS

The Project is subject to certain federal and state air quality regulations. This section summarizes the air permitting requirements and key air quality regulations that would apply to the operation of the proposed DWP. Specifically, applicability to air permitting programs such as NSR, federal emissions standards such as NSPS and NESHAP, and applicable state air regulations are addressed.

4.1 Federal Permitting Programs

Federal permitting programs comprise requirements for construction of new major stationary sources or modification of existing major stationary sources (NSR) and for operation of major sources of air pollutants (Title V Air Operating Permit Program).

4.1.1 New Source Review

Federal NSR requires that construction of new emission sources or modifications to existing emission sources be evaluated when a significant project emissions increase and a significant net emissions increase result. Two distinct NSR permitting programs apply depending on whether the facility is located in an attainment or nonattainment area for a particular pollutant; nonattainment NSR permitting is required for facilities located in nonattainment areas, while PSD permitting is required for facilities located in attainment areas.

The DWP will be located approximately eighty-two (82) statute miles from the nearest point of the Louisiana coastline. The nearest Parish onshore is Cameron Parish, Louisiana. Cameron Parish is designated by the EPA as "attainment" or "unclassifiable" with NAAQS for all criteria pollutants.[32]

Therefore, the Project is not subject to offshore NNSR permitting requirements for any criteria pollutants. Under PSD permitting rules, the major source threshold is 250 tpy unless the facility is listed specifically in 40 CFR §52.21(b)(1)(i)(a) as having a lower 100 tpy threshold. The Project is not included on the list of operations subject to the more stringent 100 tpy threshold. As such, the Project will be subject to PSD permitting should emissions from the facility exceed the major source threshold of 250 tpy of any regulated NSR pollutant.

The following table presents the Project potential emissions in comparison to the major source thresholds.

[32] 40 CFR §81.319.

Table 4-1. Major Stationary Source Determination

Regulated NSR Pollutant	Potential Emissions (tpy)	PSD Major Source Threshold (tpy)	Major Source?
NO_X	448.8	250	**YES**
CO	817.3	250	**YES**
VOC	2,473	250	**YES**
SO_2	14.66	250	No
PM-filterable	3.88	250	No
PM_{10}	16.00	250	No
$PM_{2.5}$	16.00	250	No
H_2S	1.04	250	No
H_2SO_4	0.05	250	No

Based on the potential operating emissions calculations for stationary sources, the Project is a major stationary source as potential emissions of a regulated NSR pollutant exceeds 250 tpy. As a new major stationary source, BMOP calculated emissions increases in accordance with 40 CFR §52.21(d).

> *A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit… from each emissions unit following completion of the project and the baseline actual emissions… of these units before the project equals or exceeds the significant amount for that pollutant…*

The baseline emissions are considered zero for this analysis, and the project emissions increase is equal to the Project potential emissions. The following summarizes the project emissions increase in comparison to the significant emission rates (SER) for relevant regulated NSR pollutants (per 40 CFR §52.21(b)(23)).

Table 4-2. Project Emissions Increase Evaluation

Regulated NSR Pollutant	Potential Emissions (tpy)	Significant Emissions Rate[a] (tpy)	Above SER?
NO_X	448.8	40	**YES**
CO	817.3	100	**YES**
VOC	2,473	40	**YES**
SO_2	14.66	40	No
PM-filterable	3.88	25	No
PM_{10}	16.00	15	**YES**
$PM_{2.5}$	16.00	10	**YES**
H_2S	1.04	10	No
H_2SO_4	0.05	7	No
GHG (CO_2e)	494,797	75,000	**YES**

a. "Significant" for GHG is defined under 40 CFR §52.21(b)(49)(iii).

As identified in the table above, the Project exceeds the SER for VOC, NO_X, CO, PM_{10}, $PM_{2.5}$, and GHG. Accordingly, PSD review is required for VOC, NO_X, CO, PM_{10}, $PM_{2.5}$, and GHG. BMOP is submitting this application encompassing the requirements for a PSD air permit application.

4.1.2 Title V Air Operating Permit Program

Title V air operating permits are required for major stationary sources of air pollutants on the OCS, beyond state's seaward boundaries, as defined in 40 CFR §71. Based on potential emission calculations provided in Table 3-1, the Project will be a Title V major source since potential emissions exceed the Title V major source threshold for NO_X, CO, VOC, and HAP. BMOP has submitted an application for a Title V Air Operating Permit under separate cover.

4.1.3 State Permitting Program

The DWPA identifies that the law of the nearest adjacent coastal state will apply to a DWP, such as the proposed Project.[33] The nearest adjacent coastal state is Louisiana.

4.1.3.1 Louisiana Permitting Program

Louisiana's State Implementation Plan (SIP) provides the requirements for state permitting of construction or modification of emissions sources and operation of emission sources in Louisiana Administrative Code (LAC) 33.III.Chapter 5 – Permit Procedures, regulated by the LDEQ.

The LDEQ permitting provisions of this Chapter apply to the owner and operator of any source which emits or has the potential to emit any air contaminant.

Such sources include, but are not limited to:

- Any major source as defined LAC 33:III.502.A;
- Any nonmajor (area) source of hazardous air pollutants required to obtain an operating permit pursuant to regulations promulgated under Section 112 of the federal Clean Air Act; and
- Any nonmajor (minor) source that does not meet the exemptions specified in LAC 33:III.501.B and is thus required to obtain an air quality permit.

The Project will be subject to federal major source permitting under the PSD pre-construction program, as discussed previously. As such, this application is submitted for review and a permitting determination by EPA Region 6, and will be subject to regulations under Louisiana's SIP, as applicable.

4.2 Air Quality Regulations

The Project is potentially subject to federal and state regulations for air quality control. This section describes the applicability, criteria and principal requirements of federal, state, and local regulations that result in permit conditions for the offshore components of the Project.

4.2.1 Federal Regulations

This section outlines the federal applicability analysis. Both NSPS and NESHAP are evaluated.

[33] 33 USC §1518(b).

4.2.1.1 New Source Performance Standards (NSPS)

NSPS require new, modified, or reconstructed sources to control emissions to the level achievable by the best demonstrated technology as specified in the applicable provisions. Moreover, any source subject to an NSPS is also subject to the general provisions of Subpart A, except as noted. Following is a discussion of potentially applicable subparts for the Project.

4.2.1.1.1 NSPS Subpart K – Volatile Organic Liquid Storage Vessels

NSPS Subpart K, *Standards of Performance for Storage Vessels for Petroleum Liquids for which Construction, Reconstruction, or Modification Commenced After June 11, 1973 and Prior to May 19, 1978*, regulates storage vessels for petroleum liquids with a capacity greater than 151,416 liters (40,000 gallons) which construction, reconstruction, or modification commenced after March 8, 1974, and prior to May 19, 1978. Subpart K also applies to storage vessels greater than 246,052 liters (65,000 gallons) that commenced construction or modification after June 11, 1973, and prior to May 19, 1978.

All of the Project's storage vessels will be constructed after May 19, 1978, and thus the Project is not subject to the requirements of Subpart K.

4.2.1.1.2 NSPS Subpart Ka – Volatile Organic Liquid Storage Vessels

NSPS Subpart Ka, *Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction Reconstruction, or Modification Commenced After May 18, 1978 and Prior to July 23, 1984*, regulates storage vessels for petroleum liquids with a capacity greater than 151,412 liters (40,000 gallons) which construction, reconstruction, or modification commenced after May 18, 1978, and prior to July 23, 1984.

All of the Project's storage vessels will be constructed after July 23, 1984, and thus the Project is not subject to the requirements of Subpart Ka.

4.2.1.1.3 NSPS Subpart Kb – Volatile Organic Liquid Storage Vessels

NSPS Subpart Kb, *Standards of Performance for Volatile Organic Liquid Storage Vessels*, regulates storage vessels with a capacity greater than or equal to 75 cubic meters (m^3) (19,813 gallons) that are used to store volatile organic liquids for which construction, reconstruction, or modification commenced after July 23, 1984.

NSPS Subpart Kb has provisions in §60.110b(b) to exempt tanks based on size and the maximum TVP of the material stored. Specifically, NSPS Subpart Kb "does not apply to storage vessels with a capacity greater than or equal to 151 m^3 (39,890 gallons) storing a liquid with a maximum TVP less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 (19,813 gallons) but less than 151 m^3 (39,890 gallons) storing a liquid with a maximum TVP less than 15.0 kPa." Vessels permanently attached to mobile vehicles such as trucks, railcars, barges, or ships are not subject to this subpart. In addition, process vessels do not meet the definition of a storage vessel per 40 CFR §60.111b.

The offshore Project includes the following storage vessels with a capacity greater than 19,813 gallons:

- One (1) 42,000 gallon crude oil surge tank located at the DWP platform.

However, the surge tank is considered a process vessel and is therefore not subject to NSPS Subpart Kb. EPA provided additional guidance that process tanks are exempt from Subpart Kb and that vessels used for

pipeline surge control (not storage) are considered to be process tanks.[34] As such, the Project is not subject to the requirements of NSPS Subpart Kb.

4.2.1.1.4 NSPS Subpart IIII – Stationary Compression Ignition Internal Combustion Engines

NSPS Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* applies to owners or operators of compression ignition (CI) internal combustion engines (ICE) that commenced construction, reconstruction or modification after July 11, 2005 and were manufactured after April 1, 2006 if not fire pump engines, and after July 1, 2006 if certified fire pump engines.

BMOP proposes the following CI ICE, located on the DWP platform, that are subject to the requirements of NSPS Subpart IIII:

- One (1) 336 kW (~450 hp) emergency diesel generator (40 CFR §60.4100(a)(2)(i));
- Two (2) 354 kW (~475 hp) non-emergency diesel crane engines (40 CFR §60.4100(a)(2)(i)); and
- Two (2) 485 kW (~650 hp) emergency diesel firewater pump engines (40 CFR §60.4100(a)(2)(ii)).

The one (1) 336 kW (~450 hp) emergency diesel generator will be subject to 40 CFR §60.4205(b), which states that owners or operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with emission standards for new CI engines in 40 CFR §60.4202. Per 40 CFR §60.4202(a)(2), 2007 model year or later emergency CI ICE <3,000 hp and displacement <10 L/cylinder that are not fire pump engines, must meet standards in 40 CFR § 1039, Appendix I and 40 CFR § 1039.105 (as applicable). Table 1 to Appendix I of 40 CFR §1039 limits emissions standards to the following for engines between 130kW to 560 kW:

- Non-methane hydrocarbons (NMHC) + NO_X – 4.0 g/kW-hr
- CO - 3.5 g/kW-hr
- PM - 0.2 g/kW-hr

The two (2) 354 kW (~475 hp) non-emergency diesel crane engines at WC 509 will be subject to 40 CFR §60.4204(b), which states that owners or operators of 2007 model year or later non-emergency stationary CI ICE with a displacement of less than 30 liters/cylinder must comply with emission standards for new CI engines in 40 CFR §60.4201. Per 40 CFR §60.4201(a), 2007 model year or later non-emergency CI ICE <3,000 hp and displacement <10 liters/cylinder must meet standards in 40 CFR §1039.101 (as applicable). Per Table 1 of 40 CFR §1039.101, for engines that are model year 2014 or later, between 130 kW and 560 kW, emission standards are as follows. Per 40 CFR §1039.101(e), exhaust emissions from the engines may not exceed the applicable NTE standards, which for the applicable pollutants (NO_X, NMHC, and PM) is 1.5 times the standard. The following emissions standards have included the appropriate NTE multiplier for the engines.

- PM - 0.03 g/kW-hr
- NO_X - 0.6 g/kW-hr
- NMHC (VOC) - 0.29 g/kW-hr
- CO - 3.5 g/kW-hr

The two (2) 485 kW (~650 hp) emergency diesel firewater pumps will be subject to 40 CFR §60.4205(c), which states that owners or operators of fire pump engines with a displacement of <30 liters/cylinder must

[34] 68 FR 59329-59330, October 15, 2003.

comply with emission standards in Table 4 of NSPS Subpart IIII. Per Table 4, model year 2009 or later engines with a maximum engine power greater than or equal to 450 kW and less than or equal to 560 kW must meet the following emission standards:

- NMHC + NO_X - 4.0 g/kW-hr (3.0 g/bhp-hr)
- CO - 3.5 g/kW-hr (2.60 g/bhp-hr)
- PM - 0.2 g/kW-hr (0.15 g/bhp-hr)

Per 40 CFR §60.4209(a) and §60.4214(b), owners of emergency stationary CI ICE that do not meet the standards applicable to non-emergency engines must install a non-resettable hour meter prior to startup of the engine and keep records of the operation of the engine in emergency and non-emergency service. For all the CI ICEs, the owner must purchase an engine certified to the emission standards and install and configure the engine according to manufacturer's specifications, per 40 CFR §60.4211(c).

4.2.1.1.5 NSPS Subpart JJJJ – Stationary Spark Ignition Internal Combustion Engines

NSPS Subpart JJJJ, *Standards of Performance for Stationary Spark Ignition Internal Combustion Engines* applies to owners or operators of spark ignition ICE that commenced construction or were modified or reconstructed after June 12, 2006.

The two (2) proposed 1,736 kW (~2,328 hp) natural gas fired generators at the proposed DWP are considered spark ignition ICE and are subject to NSPS Subpart JJJJ per 40 CFR §60.4230(a)(4)(i). Per 40 CFR §60.4233(e), engines greater than 100 hp must comply with the emission standards in Table 1 of Subpart JJJJ.

Non-emergency lean burn engines greater than 1,350 hp manufactured after July 1, 2010 must meet the following emission standards, according to Table 1 of NSPS Subpart JJJJ:

- NO_X - 1.0 g/hp-hr or 1.36 g/kW-hr (82 ppmvd at 15% O_2)
- CO - 2.0 g/hp-hr or 2.72 g/kW-hr (270 ppmvd at 15% O_2)
- VOC - 0.7 g/hp-hr or 0.95 g/kW-hr (60 ppmvd at 15% O_2)

Per 40 CFR §60.4243(b), the owner must either purchase a certified engine, or if purchasing a non-certified engine, complete performance testing per 40 CFR §60.4244 to demonstrate compliance with emission limits. Initial performance testing is required within 180 days of startup (per Subpart A) and subsequent testing every 8,760 hours or 3 years, whichever comes first. Per 40 CFR §60.7(a)(3), initial notification is due within 15 days of startup.

4.2.1.1.6 NSPS Subpart OOOO – Crude Oil and Natural Gas Production, Transmission, and Distribution

NSPS Subpart OOOO, *Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution* establishes emission standards and compliance schedules for the control of VOC and SO_2 emissions from affected facilities that commence construction, modification, or reconstruction after August 23, 2011. Only onshore affected facilities are subject, which exclude all facilities located in the territorial seas or on the OCS.[35] Therefore, NSPS Subpart OOOO does not apply to the Project.

[35] Definition of "onshore" at 40 CFR §60.5430.

4.2.1.1.7 NSPS Subpart OOOOa – Crude Oil and Natural Gas Facilities

NSPS Subpart OOOOa establishes emission standards and compliance schedules for the control of GHG, VOC, and SO_2 emissions from affected facilities that commence construction, modification, or reconstruction after September 18, 2015. Similar to Subpart OOOO, above, affected facilities include only onshore operations. Therefore, NSPS Subpart OOOOa does not apply to the Project.

4.2.1.2 National Emission Standards for Hazardous Air Pollutants

NESHAP are emission standards for HAP and are applicable to major and area sources of HAP. A HAP major source is defined as having potential total HAP emissions in excess of 25 tpy and/or potential individual HAP emissions in excess of 10 tpy. An area source is a stationary source that is not a major source. Part 61 NESHAPs are chemical based NESHAPs, while Part 63 NESHAP allowable emission limits are established on the basis of a MACT determination for a particular source category. NESHAP apply to sources in specifically regulated industrial source categories (CAA Section 112(d)) or on a case-by-case basis (Section 112(g)) for facilities not regulated as a specific industrial source type. The Project is a major source of HAP, as potential individual and total HAP emissions are greater than 10 and 25 tpy, respectively.

Similar to NSPS, any source subject to a NESHAP is also subject to the general provisions of the respective NESHAP Subpart A, unless specifically excluded.

4.2.1.2.1 40 CFR §61 Subpart V - Equipment Leaks (Fugitive Emission Sources)

NESHAP Subpart V, *NESHAP for Equipment Leaks (Fugitive Emission Sources)* applies to the following sources that are intended to operate in volatile hazardous air pollutant (VHAP) service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by the subpart.

A 'VHAP' and 'in VHAP' service are respectively defined in 40 CFR §61.241 as:

> *VHAP means a substance regulated under this part for which a standard for equipment leaks of the substance has been proposed and promulgated. Benzene is a VHAP. Vinyl chloride is a VHAP.*
>
> *In VHAP service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 10 percent by weight a volatile hazardous air pollutant (VHAP) as determined according to the provisions of §61.245(d). The provisions of §61.245(d) also specify how to determine that a piece of equipment is not in VHAP service.*

The crude oil to be handled and loaded at the DWP will contain benzene at less than 10% by weight. As such, the pipeline components regulated by this subpart will not operate "in VHAP service", as defined in 40 CFR §61.241. Therefore, Subpart V does not apply to the Project.

4.2.1.2.2 40 CFR §63 Subpart B – Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections 112(g) and 112(j)

Per 40 CFR §63.40(b), the use of CALM-buoys in exposed waters to load crude oil into VLCCs (and other crude oil carriers) for export to the global market is potentially subject to Subpart B of Part 63.

> *The requirements of §63.40 through §63.44 of this subpart apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants after the effective date of*

section 112(g)(2)(B) (as defined in §63.41) and the effective date of a title V permit program in the State or local jurisdiction in which the major source is (or would be) located unless the major source in question has been specifically regulated or exempted from regulation under a standard issued pursuant to section 112(d), section 112(h), or section 112(j) and incorporated in another subpart of part 63, or the owner or operator of such major source has received all necessary air quality permits for such construction or reconstruction project before the effective date of section 112(g)(2)(B).

While BMOP previously prepared and submitted a case-by-case MACT application in accordance with Section 112(g) of the CAA to the EPA on September 28, 2020, the EPA stated their belief on September 13, 2022, that *NESHAP for Marine Tank Vessel Loading Operations* (40 CFR Part 63, Subpart Y) applies to the Project. In accordance with EPA's stated belief, the Project is not subject to Subpart B.

4.2.1.2.3 40 CFR §63 Subpart H – Equipment Leaks

NESHAP Subpart H, *NESHAP for Equipment Leaks* applies to pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, instrumentation systems, and control devices or closed vent systems required by this subpart that are intended to operate in organic hazardous air pollutant service 300 hours or more during the calendar year within a source subject to the provisions of a specific subpart in 40 CFR §63 that references this subpart. No Part 63 subpart that applies to the Project references this Subpart H. Furthermore, "in organic HAP service" is defined in 40 CFR §63.161 as:

... a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP's as determined according to the provisions of §63.180(d) of this subpart. The provisions of §63.180(d) of this subpart also specify how to determine that a piece of equipment is not in organic HAP service.

The Project will not operate pipeline components that are in organic HAP service; therefore, BMOP has determined that NESHAP Subpart H is not applicable to the Project.

4.2.1.2.4 40 CFR §63 Subpart Y – Marine Tank Loading Operations

NESHAP Subpart Y, *NESHAP for Marine Tank Loading Operations*, applies to marine tank loading operations located at major or area sources of HAP emissions. The Project will be a major source of HAP. In accordance with the September 13, 2022, letter, the EPA believes that the Project is subject to Subpart Y requirements for new major offshore loading terminals.

Following this interpretation, the Project would be considered a new major source offshore loading terminal as defined in 40 CFR § 63.561. 40 CFR Part 63, Subpart Y, is unique for NESHAP standards, as it includes both MACT standards, as well as reasonably available control technology (RACT) standards. The applicable MACT standards are delineated below. The RACT standards of Subpart Y are not applicable to the Project.[36]

[36] *Existing* offshore loading terminals are explicitly exempted from both MACT and RACT standards (40 CFR § 63.560(d)(6)). For *new* offshore loading terminals, Subpart Y is explicit with an applicable MACT standard, but silent as to RACT (40 CFR § 63.562(b)(4)). This silence is intentional; it would be illogical for a more stringent RACT standard to be applicable without specific confirmatory language. Further, in the preamble to the Final Rule, EPA (1) "determined that offshore terminals loading 10 million barrels or more per year of gasoline or 200 million barrels or more of crude oil *should not* be required to control VOC or HAP emissions under section 183(f) RACT requirements" and (2) included a table of applicable standards, in which "new major source terminals located more than 0.8 kilometers (0.5 miles) offshore" need only meet Section 112 (i.e. MACT) standards. See 60 Fed. Reg. at 48,389, 48,393.

MACT Standards
The DWP is subject to the MACT standards in 40 CFR § 63.562(b) including:

- The operation of a vapor collection system to collect HAP vapors displaced from marine tank vessels during loading operations and to prevent HAP vapors collected at one loading berth from passing through another loading berth into the atmosphere [40 CFR § 63.562(b)(1)(i)];
- The limitation of marine tank vessel loading operations to vessels equipped with vapor collection equipment that is compatible with the terminal's vapor collection system [40 CFR § 63.562(b)(1)(ii)];
- The limitation of marine tank vessel loading operations to vessels which are vapor tight and connected to the vapor collection system [40 CFR § 63.562(b)(1)(iii)]; and
- For new major source offshore loading terminals, the reduction of HAP emissions from marine tank vessel loading operations by 95 weight percent [40 CFR § 63.562(b)(4)].
- Option to apply for a maintenance allowance for loading berths based on a percent of annual throughput of annual marine tank vessel loading operation time [40 CFR § 63.562(b)(6)]. Records of all maintenance performed on the air pollution control equipment shall be maintained.
  - BMOP is using this option to apply for a maintenance allowance for the loading berths at the DWP. BMOP's maintenance allowance is based on 629 hours, annually, of marine tank vessel loading operation time. The application for the maintenance allowance is included in Appendix E of this submittal.

Per 40 CFR §63.562(e), BMOP will be required to operate and maintain the source, including associated air pollution control equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. BMOP shall develop a written operation and maintenance plan that describes in detail a program of corrective action for varying air pollution control equipment and monitoring equipment in accordance with 63.562(e)(2), which will be used to demonstrate compliance with the MACT standard.

Compliance Requirements

BMOP is required to follow the vapor-tightness requirements for the marine vessel to be loaded, in accordance with 40 CFR § 63.563(a)(4):
- Provide a copy of the vapor-tightness pressure documentation described in § 63.567(i) for each marine tank vessel prior to loading [40 CFR § 63.563(a)(4)(i)];
- If no documentation of the vapor-tightness pressure test is available, then provide the leak test documentation described in § 63.567(i) prior to loading [40 CFR § 63.563(a)(4)(ii)];
  - The date of leak test must be within the preceding 12 months, and must have been conducted in accordance with § 63.565(c)(2).
  - If the marine tank vessel has failed its most recent vapor-tightness leak test at that terminal, the owner or operator of the non-vapor-tight marine tank vessel shall provide documentation that the leaks detected during the previous vapor-tightness test have been repaired and documented with a successful vapor-tightness leak test described in § 63.565(c)(2) conducted during loading.
    - If the owner or operator of the marine tank vessel can document that repair is technically infeasible without cleaning and gas freeing or dry-docking the vessel, the owner or operator of the affected source may load the marine tank vessel.
- If no documentation of vapor tightness is available, the owner or operator of a marine tank vessel shall perform a leak test of the marine tank vessel during marine tank vessel loading operation using the procedures described in § 63.565(c)(2) [40 CFR § 63.563(a)(4)(iii)];
  - If no leak is detected during testing, the owner or operator of the marine vessel must complete the documentation in § 63.567(i).

- If a leak is detected, the owner or operator of the marine tank vessel shall document the vapor-tightness failure for the marine tank vessel prior to departure of the vessel. The leaking component shall be repaired prior to the next marine tank vessel loading operation at a controlled terminal unless the repair is technically infeasible without cleaning and gas freeing or dry-docking the vessel. If the owner or operator of the vessel provides documentation that repair of such equipment is technically infeasible without cleaning and gas freeing or dry-docking the vessel, the equipment responsible for the leak will be excluded from future Method 21 tests until repairs are effected. A copy of this documentation shall be maintained by the owner or operator of the affected source. Repair of the equipment responsible for the leak shall occur the next time the vessel is cleaned and gas freed or dry-docked. For repairs that are technically feasible without dry-docking the vessel, the owner or operator of the affected source shall not load the vessel again unless the marine tank vessel owner or operator can document that the equipment responsible for the leak has been repaired.

► Ensure that a marine tank vessel is loaded with the product tank below atmospheric pressure (i.e., at negative gauge pressure). The pressure shall be measured between the facility's vapor connection and its manual isolation valve, and the measured pressure must be below atmospheric pressure. Following the date on which the initial performance test is completed, marine tank vessel loading operations for non-vapor-tight vessels must be performed below atmospheric pressure (i.e., at negative gauge pressure) in the product tank [40 CFR § 63.563(a)(4)(iii)];

Testing Requirements

► An initial performance test of the VCU control system is required within 180 days after the compliance date per 40 CFR § 63.563(b)(1). All testing shall be performed during the last 20 percent of loading of a tank or compartment per § 63.565(d)(2). The emissions testing intervals shall consist of each 5 minute period during the performance test in accordance with § 63.565(d). During initial performance testing, BMOP must determine the efficiency of and/or the outlet VOC concentration from the combustion device per § 63.563(b)(4).
  - BMOP shall establish as an operating parameter for the baseline VOC concentration using the procedures described in § 63.565(g). Following the initial performance test, the facility shall operate with a block average outlet VOC concentration no more than 20% above the baseline VOC concentration; or
  - BMOP shall establish an operating parameter for the baseline temperature using the procedures described in § 63.565(f) – either during the performance testing or from the manufacturer recommended minimum operating temperature for combustion devices. Following the initial performance test, the facility shall operate with the block average temperature as determined in § 63.564(e)(2) or (3) no more than 28°C (50°F) below the baseline temperature.

► BMOP shall inspect and monitor all ductwork and piping and connections to vapor collection systems and control devices once each calendar year using Method 21 [40 CFR § 63.563(c)(1)];

► If evidence of a potential leak is found, all ductwork, piping, and connections to the vapor collection system and control devices shall be inspected to the extent necessary to positively identify the potential leak and any potential leaks shall be monitored within 5 days by Method 21. Each detection of a leak shall be recorded, and the leak shall be tagged until repaired [40 CFR § 63.563(c)(2); and

► When a leak is detected, a first effort to repair the vapor collection system and control device shall be made within 15 days or prior to the next marine tank vessel loading operation, whichever is later [40 CFR § 63.563(c)(3)].

Test Methods and Procedures

- When testing a vessel for vapor tightness to comply with the marine vessel vapor-tightness requirements of § 63.563(a)(4)(i), the owner or operator shall use the methods delineated in § 63.565(c)(1) or (c)(2).
- For combustion devices, the average VOC concentration in the vent upstream and downstream shall be determined using Method 25 of appendix A of part 60 of this chapter for combustion devices, except flares. The average VOC concentration shall correspond to the volume measurement by taking into account the sampling system response time [40 CFR § 63.565(d)(4)]. Alternative test procedures may be submitted to EPA for review and approval 60 days prior to testing in accordance with § 63.565(m) and § 63.7(f).

Monitoring Requirements

BMOP will determine continuing compliance of the VCU control system by monitoring either of the following:

- A temperature monitor accurate to within ±10 °F or within 1 percent of the baseline temperature, whichever is less stringent, shall be installed, calibrated, and maintained per § 63.564(e)(4). The monitor shall be installed at the exhaust of each VCU, but not within the combustion zone, and shall measure and record the temperature every 15-minutes. The accuracy of the temperature monitor shall be verified once each calendar year with a reference temperature monitor. Monitored temperature shall be reduced to an average temperature each hour/cycle and a 3-hour/cycle block average every third hour/cycle per § 63.564(e)(2) or (3). Following the date that the initial performance test is completed, the 3-hour block average temperature shall be operated no more than 50 °F below the baseline temperature per § 63.563(b)(4)(ii).
- Alternatively, in accordance with § 63.564(e)(1), the VOC concentrations may be monitored at the exhaust point of the combustion device and recorded . For sources monitoring the outlet VOC concentration established during the performance test, a data acquisition system shall record a concentration every 15 minutes and shall compute and record an average concentration each cycle (same time period or cycle as the performance test) and a 3-cycle block average concentration every third cycle. The owner or operator will install, calibrate, operate, and maintain a CEMS consistent with the requirements of PS 8 to measure the VOC concentration. The daily calibration requirements are required only on days when marine tank vessel loading operations occur.

Recordkeeping and Reporting Requirements

- BMOP shall maintain a documentation file for each marine tank vessel loaded to reflect current test results as determined by the appropriate vapor tightness method per 40 CFR § 63.567(c);
- BMOP shall calculate an annual estimate of HAP emissions from marine tank vessel loading operations in accordance with 40 CFR § 63.565(l). BMOP shall maintain records of all measurements, calculations, and other documentation, and submit annual reports in accordance with 40 CFR § 63.567(j);
- BMOP shall maintain information for 5 years for each leak detected and repaired in accordance with 40 CFR § 63.567(k);
- BMOP is required to submit initial notification in accordance with 40 CFR § 63.9(b)(i);
- BMOP shall notify the Administrator in writing of the intention to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin to allow the Administrator to review and approve the site-specific test plan required under § 63.7(c), if requested by the Administrator, and to have an observer present during the test [40 CFR § 63.9(e)];
- BMOP shall submit summary reports and excess emissions and monitoring system performance reports in accordance with 40 CFR § 63.567(e).

BMOP must comply with the general notification requirements per 40 CFR § 63.9, and recordkeeping and reporting requirements per 40 CFR § 63.10 in accordance with Table 1 to 40 CFR § 63.560.

4.2.1.2.5 40 CFR §63 Subpart HH – Oil and Natural Gas Production Facilities

NESHAP Subpart HH, *NESHAP from Oil and Natural Gas Production Facilities,* applies to owners and operators of affected sources at oil and natural gas production facilities at major or area sources of HAP emissions. The Project is not considered an oil and natural gas production facility per 40 CFR §63.760(a)(3), as it does not process, upgrade or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. Therefore, the Project is not subject to Subpart HH.

4.2.1.2.6 40 CFR §63 Subpart VV – Oil-Water Separators and Organic-Water Separators

NESHAP Subpart VV, *NESHAP for Oil-Water Separators and Organic-Water Separators,* applies to the control of air emissions from oil-water separators and organic-water separators for which another subpart of 40 CFR Parts 60, 61, or 63 references the use of this subpart for such air emission control. No Part 63 subpart that applies to the Project references Subpart VV. Therefore, BMOP has determined that NESHAP Subpart VV is not applicable to the Project.

4.2.1.2.7 40 CFR §63 Subpart HHH – Natural Gas Transmission and Storage Facilities

Per 40 CFR §63.1270(a) and (b), Subpart HHH applies to glycol dehydration units at major sources of HAP. The Project does not involve any glycol dehydration units; therefore, Subpart HHH is not applicable.

4.2.1.2.8 40 CFR §63 Subpart EEEE – Organic Liquids Distribution (Non-Gasoline)

NESHAP Subpart EEEE, *NESHAP for Organic Liquids Distribution (Non-Gasoline),* applies to organic liquids distribution (OLD) operations at, or part of, a major source of HAP emissions. Subpart EEEE includes standards for the following sources (40 CFR §63.2338):

- Storage tanks storing organic liquids
- Transfer racks at which organic liquids are loaded into, or unloaded out of, transport vehicles and/or containers
- All equipment leak components in organic liquid service that are associated with:
  - Storage tanks
  - Transfer racks
  - Pipelines between storage tanks and transfer racks
  - Transport vehicles and containers.

The proposed 1,000 barrel surge vessel is not a storage tank, as it is explicitly excluded from the definition of "storage tank" at 40 CFR §63.2406. The other storage tanks proposed do not store an organic liquid (excludes diesel, and fuels used for refueling). In addition, the project will not include a transfer rack, as the delivery of crude is to marine vessels, not to a cargo tank or tank car.

As such, the Project is not subject to requirements under Subpart EEEE.

4.2.1.2.9 40 CFR §63 Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines

NESHAP Subpart ZZZZ, *NESHAP for Stationary Reciprocating Internal Combustion Engines*, applies to reciprocating internal combustion engines (RICE) located at major or area sources of HAP emissions. A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy

into mechanical work and which is not mobile. For engines located at a major source of HAP emissions, a stationary RICE is 'new' if the unit commenced construction or reconstruction on or after December 19, 2002 and if the engine has a site rating of more than 500 hp or on or after June 12, 2006 and if the engine has a site rating of less than or equal to 500 hp (40 CFR §63.6590(a)(2)(i) and (ii)). All the proposed engines associated with the WC 509 platform complex are considered 'new'.

Per 40 CFR §63.6590(c)(7), new CI stationary RICE with a site rating of less than or equal to 500 brake hp located at a major source of HAP emissions must meet the requirements of NESHAP ZZZZ by demonstrating compliance with NSPS Subpart JJJJ or IIII, respectively. This applies to the following RICE associated with the DWP project:

- Two (2) 354 kW (~475 hp) non-emergency diesel crane engines; and
- One (1) 336kW (~450 hp) emergency diesel generator.

These engines have no further requirements under Subpart ZZZZ.

The two (2) proposed 1,736 kW (~2,328 hp) natural gas fired generators are four-stroke, lean burn spark ignition ICE and must comply with the emissions limitations in Table 2a and the operating limitations in Table 2b, per 40 CFR §63.6600(b), as provided below:

- Four-stroke lean burn engines must reduce CO emissions by 93% or more or limit the concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15% O_2 [Table 2a];
- Maintain catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test [Table 2b]; and
  - Demonstrate initial compliance with CO reduction or formaldehyde limit in accordance with Table 5 [§63.6630(a)].
  - During the initial performance test, establish each operating limitation described above [§63.6630(b)].
  - Conduct initial performance testing per Table 4 of this subpart within 180 days of startup and in accordance with §63.7(a)(2) [§63.6610(a) and Table 4].
  - Submit a notification of compliance status containing the results of the initial compliance demonstration according to the requirements of §63.6645 [§63.6630(c)].
  - Conduct semi-annual performance tests for CO to demonstrate that the required CO percent reduction is achieved [§63.6615, §63.6640(a), Table 3 and Table 6].
- Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450°F and less than or equal to 1350°F [Table 2b].
  - Install, operate, and maintain a temperature continuous parameter monitoring system (CPMS) that meets the requirements of §63.6625(b) [§63.6625(b)].
  - Continuously collect and reduce data to 4-hour averages [§63.6635, §63.6640(a) and Table 6];
- Per 40 CFR §63.6605, at all times you must be in compliance with the emission limitations, operating limitations, and operate and maintain the engine, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions;
- Per 40 CFR §63.6625(h), any new stationary engine must minimize engine idle time at startup and limit startup period to less than 30 minutes;
- Report each instance in which the engine did not meet the emission or operating limitations as deviations according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you

reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE. Deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. [§63.6640(b) and (d)];

- Per 40 CFR §63.6650 and Table 7, submit compliance reports semi-annually according to the requirements of §63.6650(b)(1)-(5). These reports are due July 31 and January 31 for the periods of January 1 – June 30 and July 1 – December 31, respectively. These reports must contain the information included in §63.6650(c), (d), and (e), if applicable; and
- Maintain records as specified in §63.6655(a),(b)&(d) for 5 years [§63.6655 and §63.6660].

The two (2) 485 kW (~650 hp) emergency diesel firewater pump engines are subject only to an initial notification requirement of 40 CFR § 63.6645(f), in accordance with 40 CFR § 63.6590(b)(1)(i). No other requirements of Subpart ZZZZ or Subpart A apply.

4.2.1.3 Risk Management Program

Requirements under 40 CFR §68, Chemical Accident Provisions, require submittal of a Risk Management Plan if the facility stores a regulated material above the applicable concentration and threshold values. Since BMOP will not store a regulated material above the applicable threshold limits, the Project is only subject to the General Duty Clause requirements and must review materials as purchased to verify if additional requirements must be met.

4.2.1.4 Greenhouse Gas Mandatory Reporting Rule

The EPA has promulgated monitoring, reporting, and recordkeeping rules for GHGs at 40 CFR Part 98. A facility is required to report its GHG emissions if its aggregate maximum rated heat input from all combustion sources is greater than 30 million British thermal units per hour (MMBtu/hr) and it emits more than 25,000 metric tpy of carbon dioxide equivalent (CO_2e) (40 CFR § 98.2(a)). The Project will monitor and report its GHG emissions under 40 CFR Part 98.

4.2.2 State Regulations

For Deepwater Port License Applications (DPLAs), EPA administers CAA requirements and reviews air permit applications using adjacent state's regulations. The nearest adjacent state to the DWP project's offshore location is Louisiana. Therefore, the LDEQ rules and regulations will apply to the offshore portion of the Project. The following is a discussion of potentially applicable LAC 33:III chapters for the Project.

4.2.2.1 Louisiana Air Quality Regulations

The following is a discussion of potentially applicable LAC 33:III chapters for the Project.

As discussed above, the Project is subject to Title V permitting under 40 CFR §71. For consistency with the applicable Louisiana SIP requirements, the LDEQ-required Title V Part 70 forms have been completed as part of the application.

The following LDEQ required application forms are provided in Appendix B of this application:

- The Application for Approval of Emissions of Air Pollutants from Part 70 Sources;
- Emissions Inventory Questionnaire (EIQ) Forms; and
- The Environmental Assessment Statement (EAS or "IT" Question Responses).

4.2.2.1.1 LAC 33:III Chapter 11 – Control of Emissions of Smoke

This regulation prohibits impairment of visibility due to emissions of smoke and provides an opacity limit of 20 percent from combustion smoke except during periods of maintenance. Also provided are restrictions for outdoor burning. The opacity standards set forth in LAC 33:III.1101 do not apply to combustion units when combusting only natural gas and combustion units subject to a federal standard promulgated pursuant to section 111 or 112 of the Clean Air Act that limits average opacity to less than or equal to 20 percent, except for one six-minute period or less per hour.

The diesel combustion sources located at the DWP platform will be subject to this Chapter. However, all of the combustion sources combusting only natural gas will be exempt from this rule as they meet the criteria of LAC 33:III.1107.B.1.

4.2.2.1.2 LAC 33:III Chapter 13 – Emission Standards for Particulate Matter

This regulation prohibits impairment of visibility due to emissions of PM. According to LAC 33:III.1311.C, this regulation provides an opacity limit of 20 percent from emissions of PM. This regulation applies to all combustion sources of the offshore project.

4.2.2.1.3 LAC 33:III Chapter 15 – Emission Standards for Sulfur Dioxide

This regulation applies to new or existing sulfuric acid production units, sulfur recovery plants, and all other single point sources that emit or have the potential to emit 5 tpy or more of SO_2 into the atmosphere. Since no single point source for the Project emits or has the potential to emit 5 tpy or more of SO_2, this regulation does not apply.

4.2.2.1.4 LAC 33:III Chapter 21, Section 2103 – Storage of Volatile Organic Compounds

This regulation applies to storage tanks greater than 40,000 gallons which store VOC products with a maximum TVP of 1.5 psia or greater at storage conditions. The diesel storage tanks proposed as part of the Project are not subject to this regulation since the vapor pressure of diesel is less than 1.5 psia. The 42,000 gallon crude oil surge vessel located at the WC 509B platform is exempt from this regulation per LAC 33:III 2103.G.1, since the tank has a nominal storage capacity of less than 420,000 gallons and is not subject to NSPS.

4.2.2.1.5 LAC 33:III Chapter 21, Section 2108 – Marine Vapor Recovery

This regulation applies to any marine loading operation serving ships and/or barges loading crude oil, gasoline, or VOC with uncontrolled emissions of 25 tpy or more of VOC in the parishes of Ascension, East Baton Rouge, Iberville, Livingston, and West Baton Rouge, or 100 TPY or greater of VOC in any other parish of the State of Louisiana.

Since this is an offshore project and is not located onshore in any of the Louisiana parishes, BMOP has determined that this regulation is not applicable to the Project.

4.2.2.1.6 LAC 33:III Chapter 21, Section 2111 – Pumps and Compressors

Rotary pumps and compressors that handle VOCs having a TVP greater than or equal to 1.5 psia at handling conditions must be equipped with mechanical seals or other equivalent equipment or means as approved by the administrative authority. The WC 509 platform complex does not include crude oil pumps, nor natural gas compressors. The diesel equipment does not handle VOCs having a TVP greater than or equal to 1.5

psia. Only the condensate system for the existing natural gas lines, the surge vessel, and the sump system may have pumps that will be subject to this requirement.

4.2.2.1.7 LAC 33:III Chapter 21, Section 2113 – Housekeeping

This regulation defines the practices required to maintain the "best practical housekeeping and maintenance" for area VOC control. These practices include activities such as cleaning up spills, keeping containers closed, and properly storing waste. The Project is subject to this regulation.

4.2.2.1.8 LAC 33:III Chapter 21, Section 2121 – Fugitive Emission Control

This Section is applicable to each process unit at petroleum refineries, natural gas processing plants, synthetic organic chemical manufacturing industry facilities, methyl tertiary butyl ether manufacturing facilities, and polymer manufacturing facilities. The Project is not one of the listed facility types and is not subject to this regulation.

4.2.2.1.9 LAC 33:III Chapter 51 - Comprehensive Toxic Air Pollutant Emission Control Program

The provisions of the Comprehensive Toxic Air Pollutant (TAP) Program (LAC 33:III.Chapter 51) apply to owners and operators of any major source that emits, or has the potential to emit, 10 tpy or more of any individual TAP, or 25 tpy or more of any combination of TAPs, listed in Table 51.1 of LAC 33:III.5112. The Project will be subject to this chapter. An evaluation of the TAP program is included as part of the air quality impacts analysis in Volume 2 of this PSD application.

4.2.2.1.10 LAC 33:III Chapter 56 - Prevention of Air Pollution Emergency Episodes

This regulation is designed to prevent the buildup of excess concentrations of air contaminants during periods of high air pollution potential. The Project is subject to this regulation.

4.2.2.1.11 LAC 33:III Chapter 59 - Chemical Accident Prevention and Minimization of Consequences

This regulation does not apply to the Project since it does not produce, process, handle, or store any substance listed in LAC 33:III.5907 in greater than the threshold amounts.

5. BACT ANALYSIS

This section discusses the regulatory basis for BACT, the approach used in completing the BACT analyses, and the BACT analyses for the Project. Supporting documentation is included in Appendix D of this application.

A BACT analysis was performed for NO_X, CO, VOC, $PM_{10}/PM_{2.5}$, and GHG, as the pollutants with both a significant emissions increase and a significant net emissions increase from the proposed project. This BACT analysis follows the "top-down" approach suggested by EPA, as described in more detail below.

The following emission units were considered in the BACT analysis and detailed discussions of each unit are included in the following subsections.

- Marine Loading
- Combustion Sources
  - Natural Gas-Fired Engine-Driven Generators
  - Emergency Diesel-Fired Engine-Driven Generator
  - Diesel-Fired Crane Engines
  - Emergency Diesel-Fired Engine-Driven Firewater Pumps
- Fugitive Emissions
- Storage Vessels

5.1 BACT Definition

The requirement to conduct a BACT analysis is set forth in the PSD regulations [40 CFR §52.21(j)(2)]:

> *(j) Control Technology Review.*
> *(2) A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.*

BACT is defined [40 CFR §52.21(b)(12) as:

> *...<u>an emission limitation</u> (including a visible emissions standard) based on the maximum degree of reduction for <u>each pollutant</u> subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is <u>achievable</u> for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.*

The underlined terms in the primary BACT definition above are addressed further below.

5.1.1 Emission Limitation

BACT is "an emission limitation," not an emission reduction rate or a specific technology. The BACT limit is an emissions limitation and does not require the installation of any specific control device. While BACT is prefaced upon the application of technologies reflecting the maximum reduction rate achievable, the final

result of BACT is an emission limit. Typically, when quantifiable and measurable[37], this limit would be expressed as an emission rate limit of a pollutant (e.g., lb/MMBtu, ppm, or lb/hr).[38]

5.1.2 Each Pollutant

The BACT evaluation process is typically conducted for each regulated pollutant individually and not for a combination of pollutants. For the proposed Project, NO_X, CO, VOC, $PM_{10}/PM_{2.5}$, and GHG trigger a BACT review.

5.1.3 Achievable

BACT is to be set at the lowest feasible value that is achievable. However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life.

As discussed by the DC Circuit Court of Appeals,

> *In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."* [39]

EPA has reached similar conclusions in prior determinations for PSD permits.

> *Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.* [40]

Thus, BACT must be set at the lowest feasible emission rate recognizing that the emission unit must be in compliance with that limit for the lifetime of the unit on a continuous basis. Thus, while viewing individual unit performance or proposed performance can be instructive in evaluating what BACT might be, actual performance data is given more weight than performance that has not been demonstrated and even that performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will feasibly achieve during its entire operating life. For NO_X, CO, VOC, $PM_{10}/PM_{2.5}$, and GHG BACT, BMOP must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source (see "Defining the Source" section below). In

[37] The definition of BACT allows use of a work practice where emissions are not easily measured or enforceable.

[38] Emission limits can be broadly differentiated as "rate-based" or "mass-based."

[39] As quoted in Sierra Club v. EPA (97-1686).

[40] EPA Environmental Appeals Board decision, In re: Newmont Nevada Energy Investment L.L.C. PSD Appeal No. 05-04, decided December 21, 2005. Environmental Administrative Decisions, Volume 12, Page 442.

contrast to limited snapshots of actual performance data, emission performance levels from similar sources can reasonably be used to infer what is "achievable."[41]

5.1.4 Floor

Emissions [shall not] exceed … 40 CFR §60 and §61.

The least stringent emission rate allowable for BACT is any applicable limit under either NSPS – Part 60 or NESHAP – Part 61. State SIP limitations must also be considered when determining the floor. The regulatory applicability analysis in Section 4 of this application identifies the floor for BACT for the following sources:

- Natural gas-fired engine-driven generators
  - NSPS Subpart JJJJ (40 CFR §60.4233(e) and Table 1 of Subpart JJJJ)
- Emergency diesel-fired engine-driven generator
  - NSPS Subpart IIII (40 CFR §60.4202)
- Diesel-fired crane engines
  - NSPS Subpart IIII, (40 CFR §60.4201)
- Emergency diesel-fired engine-driven firewater pumps
  - NSPS Subpart IIII (40 CFR §60.4205(c))

5.2 BACT Assessment Methodology

The primary document referenced for the general BACT methodology is EPA's 1990 *NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting* ("NSR Workshop Manual").[42] To assist applicants and regulators with the case-by-case process, EPA issued a Draft Manual on NSR permitting in 1990 which included a "top-down" BACT analysis.

The five steps in a top-down BACT evaluation can be summarized as follows:

- **Step 1**. Identify all possible control technologies;
- **Step 2**. Eliminate technically infeasible control options;
- **Step 3**. Rank the technically feasible control technologies based upon emission reduction potential;
- **Step 4**. Evaluate ranked control technologies based on energy, environmental, and/or economic considerations; and
- **Step 5**. Select BACT.

While the top-down BACT analysis is a procedural approach suggested by EPA policy, this approach is not specifically mandated as a statutory requirement of the BACT determination. The process is conducted on a unit-by-unit, pollutant-by-pollutant basis and only considers the portions of the facility that are considered "emission units" as defined under 40 CFR §52.21(b)(7).

[41] Emission limits must be used with care in assessing what is "achievable." Limits established for facilities that were never built must be viewed with care, as they have never been demonstrated and that company never took a significant liability in having to meet that limit. Likewise, permitted units that have not yet commenced construction must also be viewed with special care for similar reasons.

[42] EPA, October 1990. https://www.epa.gov/nsr/nsr-workshop-manual-draft-october-1990

5.3 BACT "Top Down" Approach

BACT in this report has been evaluated via a "top-down" approach that includes the steps outlined in the following subsections. The minimum control efficiency to be considered in a BACT assessment must result in an emission rate less than or equal to any applicable NSPS or NESHAP emission rate for the source. [43]

5.3.1 Identification of Potential Control Technologies (Step 1)

Available control technologies with the practical potential for application to the emission unit are identified. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts, control technologies with potential application to the emission unit under review are identified in this step. Under Step 1 of a criteria pollutant BACT analysis, the following resources are typically consulted when identifying potential technologies:

1. EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;
1. Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
2. Engineering experience with similar control applications;
3. Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
4. Review of literature from industrial technical or trade organizations.

BMOP performed searches of the RBLC database to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT within the past ten years for comparable emission sources. There are no existing similar sources for marine loading at CALM buoys in exposed offshore waters, 82 statute miles to the nearest point on shore. RBLC was evaluated for the following process types:

- 17.000 Internal Combustion Engines
  - 17.100 – Large Internal Combustion Engines (>500 hp)
    - 17.110 – Fuel Oil (ASTM # 1,2, includes kerosene, aviation, diesel fuel)

Two (2) 485 kW (~650 hp) emergency diesel-fired engine-driven firewater pumps

    - 17.130 – Natural Gas (includes propane & liquefied petroleum gas)

Two (2) 1,736 kW (~2,328 hp) natural gas-fired engine-driven generators

  - 17.200 – Small Internal Combustion Engines (≤500 hp)
    - 17.210 – Fuel Oil (ASTM # 1,2, includes kerosene, aviation, diesel fuel)

One (1) 336 kW (~450 hp) emergency diesel-fired engine-driven generator
Two (2) 354 kW (~475 hp) diesel-fired crane engines

- 42.000 Organic Liquid Storage & Marketing (Petroleum, Gasoline, VOL)
  - 42.004 – Petroleum Liquid Marketing (except 42.001-003 & 42.005-006)
    - Marine loading operations
    - Fugitive emissions from piping components
  - 42.005 – Petroleum Liquid Storage in Fixed Roof Tanks
    - Storage vessels (diesel fuel storage tanks, aviation fuel storage tank, surge vessel)

[43] 40 CFR §52.21(b)(12).

5.3.2 Elimination of Technically Infeasible Control Options (Step 2)

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it is demonstrated. If so, it is feasible.

Demonstrated means that it has been installed and operated successfully elsewhere on a similar facility. "This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible."[44]

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available".[45] Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: "An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration."[46] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

5.3.3 Rank of Remaining Control Technologies (Step 3)

All remaining technically feasible control options are ranked based on their overall control effectiveness for the pollutant of interest.

5.3.4 Evaluation of Most Stringent Control Technologies (Step 4)

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration, it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified.

Economic analyses were performed to compare total costs (capital and annual) for potential control technologies. Capital costs include the initial cost of the components intrinsic to the complete control system. Annual operating costs include the financial requirements to operate the control system on an annual basis and include overhead, maintenance, outages, raw materials, and utilities.

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[44] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.17.

[45] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

[46] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

The capital cost estimating technique used is based on a factored method of determining direct and indirect installation costs. That is, installation costs are expressed as a function of known equipment costs. This method is consistent with the latest EPA's Office of Air Quality Planning and Standards (OAQPS) guidance manual on estimating control technology costs.[47]

Total capital investment (TCI) represents the delivered cost of the control equipment, auxiliary equipment, and instrumentation (purchased equipment costs). Auxiliary equipment consists of all the structural, mechanical, and electrical components required for the efficient operation of the device. Auxiliary equipment costs are estimated as a straight percentage of the equipment cost. Direct installation costs consist of the direct expenditures for materials and labor for site preparation, foundations, structural steel, erection, piping, electrical, painting and facilities. Indirect installation costs include engineering and supervision of contractors, construction and field expenses, construction fees, and contingencies. Other indirect costs include equipment startup, performance testing, working capital, and interest during construction.

Annual costs are comprised of direct and indirect operating costs. Direct annual costs include labor, maintenance, replacement parts, raw materials, utilities, and waste disposal. Indirect operating costs include plant overhead, taxes, insurance, general administration, and capital charges. Replacement part costs, such as the cost of replacement of catalysts for the oxidation catalysts, were included where applicable. With the exception of overhead, indirect operating costs were calculated as a percentage of the total capital costs. The indirect capital costs were based on the capital recovery factor (CRF) defined as:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where i is the annual interest rate and n is the equipment life in years.

The equipment life is based on the normal life of the control equipment and varies on an equipment type basis. The same interest rate applies to all control equipment cost calculations. For this analysis, an interest rate of 7% was used based on information provided in the most recent OAQPS Control Cost Manual.[48] Detailed BACT cost calculations are included in Appendix D to this report.

The primary focus of the environmental impact analysis is the reduction in ambient concentrations of the pollutant being controlled. Increases and decreases in other criteria or non-criteria pollutants may occur with some technologies and should also be identified. Non-air impacts, such as solid waste disposal and increased water consumption, may be an issue as well.

5.3.5 Selection of BACT (Step 5)

In the final step, the BACT emission limit is determined for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. BACT is an emission limit unless technological or economic limitations of the measurement methodology would make

[47] EPA, *OAQPS Control Cost Manual*, 7th edition sections: https://www.epa.gov/economic-and-cost-analysis-air-pollution-regulations/cost-reports-and-guidance-air-pollution#cost%20manual

[48] https://www.epa.gov/sites/production/files/2017-12/documents/epaccmcostestimationmethodchapter_7thedition_2017.pdf

the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

5.4 Defining the Source

The EPA's NSR Workshop Manual states: "Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives."[49] The courts have confirmed EPA's use of a two-part test for determining when a considered control, for the purposes of BACT, illegitimately redefines the proposed source.

The United States Court of Appeals for the Ninth Circuit has summarized and adopted the EPA's two-part test for determining when the evaluation of an alternative production process as a control technology[50] veers into an illegitimate redefinition of the source proposed by the permit applicant.

> *First, "the permit applicant initiates the process and … defines the proposed facility's end, object, aim or purpose—that is the facility's basic design." The purpose must be "objectively discernable." Additionally, the applicant's proposed definition "must be for reasons independent of air permitting" and cannot be motivated by cost savings or avoidance of risks.*
>
> *Second, EPA takes a "hard look" at the proposed definition to determine which design elements are inherent to the applicant's purpose and which elements can be changed to reduce pollutant emissions without disrupting the applicant's basic business purpose.*[51]

The Court's two-part test can be further characterized by examples in the NSR Workshop Manual and prior permitting decisions, which are outlined as:

- Step 1: The applicant defines the project in a way that addresses:
  - The purpose of the project
  - The basic design and location to meet the project purpose
- Step 2: EPA reviews the Applicant's stated purpose and basic design elements:
  - Are the design elements inherent to the purpose?
  - Could any basic design element change without impacting the project purpose?

The following presents the Applicant's stated purpose of the project and the corresponding basic design and location.

5.4.1 Purpose of the Project and Key Design Criteria

The primary purpose of the Project is to provide for a safe and reliable long-term supply of crude oil for export to the global market. To fulfill this purpose, the Project must be capable of fully loading the international fleet of crude-carrying marine vessels to accommodate the safe and efficient transport of

[49] NSR Workshop Manual, page B-13.

[50] Again, such an evaluation is disallowed under Massachusetts regulations. Algonquin sets out this test here as an alternative method of demonstrating that EMD improperly redefines the source.

[51] *Helping Hands Tools v. Envtl. Prot. Agency*, 848 F.3d 1185, 1194 (9th Circuit 2016).

crude. Accordingly, the Project requires a DWP that can accommodate the draft and berth of a fully loaded VLCC with the ability to load in varying meteorological conditions. This ensures safety in transfer and transit by minimizing risks of transportation incidents (e.g., spills, allisions, collisions). It is not possible for existing onshore terminals in the GOM to fully load a VLCC due to limited draft. There are only a couple existing onshore terminals in the GOM that can partially load a VLCC; loading is completed offshore via reverse lightering. The proposed DWP design avoids the inefficiency and cost of idled time at a fixed port for partial VLCC loading while offering the benefit of avoiding dock-constrained ports to free up dock space for other commodities. This approach also resolves the logistical challenges and added vessel traffic of reverse lightering while mitigating the risks and additional environmental impacts of multiple loadings for a single fully-loaded VLCC.

The following are key design considerations for the siting criteria, consistent with the primary purpose of the Project:

- Location with deep water
- Location that is distant from sensitive coastal resources and that would minimize vessel traffic at inland waterways and eliminate the need for dredging
- Location near, but without interference to, designated shipping fairways
- Sufficient restricted safety area for safe transiting, maneuvering, and loading of an international fleet of VLCCs and other large seafaring crude vessels
- Loading a ship from a floating buoy, as opposed to a fixed berth for maximum availability and safety in exposed deep water subject to unique offshore weather and wave conditions
- Ability to fully load a VLCC in approximately 1 day
- A DWP design that can be called upon by the existing worldwide fleet of VLCCs or other crude oil carriers by matching worldwide fleet piping manifold pressure limitations, and that utilizes proven design that is safe to operate
- Use of existing infrastructure and facilities with a local fuel source, where possible
- Operational control and communications to enable safe loading
- Location with access to U.S. crude oil supply infrastructure, such as the Nederland Terminal, which is a key supply hub for domestic crude
- Flexibility to export a wide variety of crude oil types

These factors were specifically used in guiding the development of the proposed source, with the following conclusions dictating the basic design of the proposed source:

- Use of an existing offshore pipeline system provides access to the siting criteria to meet the Project purpose while minimizing total project impacts.
- Use of CALM buoys to provide safe, efficient, and high availability to load large seafaring vessels, including VLCCs, in the varying sea states of exposed deep water.
- Availability of an existing platform complex provides operational control and communications without requiring new structures and impacts.
- Access to the existing Nederland Terminal with the ability to provide a variety of domestic crude types for export.

With this project-specific evaluation, BMOP has identified the existing Stingray Pipeline System, which provides an existing 36-inch OD subsea pipeline from Cameron Parish, Louisiana to an existing platform complex in federal waters within and adjacent to the OCS in West Cameron Lease Block 509.

The primary purpose and identified objectives defining the basic design of the Project cannot be attained with traditional crude export and existing operations. As such, existing operations with the following design characteristics do not fit the purpose and objective of the Project, and would not be similar sources:

- Fully loading VLCCs through reverse lightering of smaller vessels shuttling back and forth to existing onshore terminals;
- Use of a fixed loading berth; or
- Customized vessels dedicated to operations shuttling uniform product types between limited, defined locations.

5.4.2 Control Alternatives that Redefine the Source

The NSR Workshop Manual and the courts have identified characteristics of control alternatives that would redefine the source inappropriately for a BACT evaluation. Relevant precedent includes an opinion by the Environmental Appeals Board (EAB), holding that design elements of a facility that support the reliability of the process are inherent to the purpose of the facility. In *City of Palmdale*, the applicant proposed to construct a hybrid natural gas-solar power plant with the purpose of providing 570 MW of baseload power. In response to a challenge that the BACT should have considered all solar power as a control alternative, the EAB concluded:

> *According to the record, however, "solar power plants alone do not produce reliable energy generation night and day." Thus, "[e]nergy production would either have to be supplemented by a storage facility to produce during the evening and night hours or would be available only throughout the daylight hours. Because of the limited energy during night hours, [the applicant] would not increase its level of assurance that residential, commercial, and industrial power needs in the City would be met, which is one of the … project objectives." In other words, such a design would be incompatible with PHPP's overarching purpose: a reliable, baseload facility… The Board concludes the [permitting authority's] determination here that an all-solar alternative would redefine the source was eminently reasonable…"*[52]

A control technology that may be consistent with the basic design and purpose of one facility does not necessarily make it so for other facilities. For the BMOP project, control technology applied to marine loading terminals that interrupt the Project purpose of a **safe** and **reliable** long-term supply of **crude oil export for the global market** redefines the source, just as applying less reliable electricity generation redefines the source for *City of Palmdale*.

The BACT for each emission unit considers the project purpose and definition of the source in completing the "top-down" BACT analysis per the NSR Workshop Manual draft guidance.

5.5 VOC BACT – Marine Loading

5.5.1 Background on Pollutant Formation

Evaporative emissions of VOC occur as organic vapors in cargo tanks on marine vessels are displaced during marine loading activities. The displaced vapors include evaporated residual product from the prior load, crude oil vapors generated in the cargo tank as the crude oil is being loaded, and inert gases added to the

[52] *In re City of Palmdale*, PSD App. No. 11-07, 2012 WL 4320533 (EAB September 17, 2012).

cargo tank for safety. The VOC emissions from marine loading at the Project are a function of the following parameters:[53]

- Physical and chemical characteristics and method of unloading the previous cargo;
- Physical and chemical characteristics of the crude oil loaded; and
- Method of loading the crude oil.

In regard to the previous cargo, these emissions are estimated by a constant arrival emissions factor, and represent an inerted vessel. The displaced vapors from marine vessel cargo tank are not uniform throughout loading. For the proposed Project, inerted vessels will arrive blanketed with inert gases to maintain oxygen concentration below 8% - specifically to make them noncombustible.[54] As well, hydrocarbon vapors are denser than air.

> *Because of its high density the gas forms a layer at the bottom of the tank which rises with the oil surface as the tank is filled. Once it has been formed the depth of the layer increases only slowly over the period of time normally required to fill a tank, although ultimately an equilibrium gas mixture is established throughout the ullage space.*
>
> *Above this layer the atmosphere originally present in the tank persists almost unchanged and it is this gas which in the early stages of loading enters the venting system. In an initially gas free tank, therefore, the gas vented at first is mainly air (or inert gas) with a hydrocarbon concentration below the Lower Explosive Limit (1 percent HC).*[55]

The physical and chemical characteristics of the crude oil loaded are dependent upon the source. For the proposed Project, the physical and chemical characteristics are based on the crude oil handling requirements and limitations of the Nederland Terminal.

The method of loading crude oil affects the rate of evaporation. Because VOC emissions from marine loading are, in part, a result of evaporated crude oil, the rate of evaporation affects total loading emissions. The Marine Board for the National Research Council has noted that faster, efficient loading can minimize air emissions.

> *Atmospheric emissions while loading cargo are minimized by filling each compartment as rapidly as possible, to reduce the amount of evaporation into the ullage space (an exception to this is at the start of loading when rapid rates may cause splashing, which increases evaporation)* [56]

As noted, reducing splashing in an effort to minimize surface area and convection-driven evaporation also minimizes VOC emissions from marine loading.

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[53] AP-42 Chapter 5.2 Transportation and Marketing of Petroleum Liquids, 6/08.

[54] 33 CFR §154.2001.

[55] International Chamber of Shipping, *International Safety Guide for Oil Tankers and Terminals*, (ISGOTT), 2d Ed, London: Witherby & Co.

[56] Marine Board, National Research Council, "Controlling Hydrocarbon Emissions from Tank Vessel Loading," 1987, page 82. (Docket A-90-44, II-I-4).

5.5.2 Identification of Potential Control Technologies (Step 1)

The following VOC emissions control technologies have been identified:

- Vapor Combustion Control
- Vapor Recovery Control
- Vapor Balancing
- Vapor Control System Onboard VLCC
- Vapor Control System Onboard Support Vessel
- Submerged Fill and VOC Best Management Practices (BMP)

5.5.2.1 Vapor Combustion Control

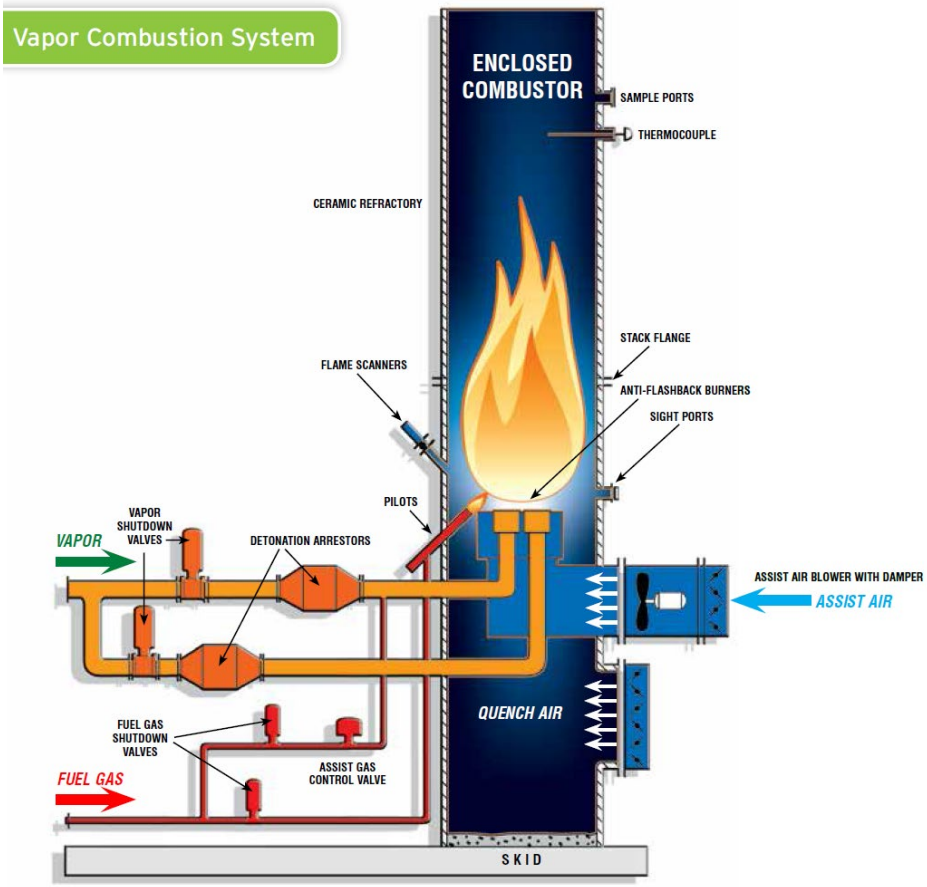
A common approach for marine loading at onshore terminals is the use of a vapor combustion unit (VCU) to control displaced organic vapors. Vapor capture systems are necessary for use of a VCU. For onshore terminals with fixed berths, dockside vapor collection hoses or arms are connected to the vessel's inert gas vapor system on the deck of the ship to capture displaced loading loss vapors. The terminal's facility vapor control system (VCS) must meet USCG safety requirements at 33 CFR Part 154. The USCG regulations require safety protection devices to be as close as possible to the vessel's connection with the facility VCS. Compliance with the safety device requirements is typically met at marine terminals with a dock safety unit (DSU), an entire skid that includes the required detonation arrester, pressure control, oxygen analyzer, and inerting/enrichment equipment. Blowers/fans are utilized to pull the displaced vapors through the facility VCS and to the VCU, and for combustion air/quench air in the combustor control.

A VCU utilizes burners to add the heat energy required to raise the temperature in the enclosed combustor to the point that VOC chemical bonds are broken. However, as discussed above, the displaced vapor composition is not uniform and inerted. A VCU requires supplemental fuel, both to sustain a pilot flame for ignition, as well as assist gas necessary to enable combustion to sustain the high temperatures required for VOC destruction. For marine loading, assist gas is often required until the vessel is loaded to 85% of full capacity, or more. The VCU control utilizes a ceramic refractory to allow quick heating and sustain temperatures to improve VOC destruction.

The following figure presents a simplified VCU control system. A VCU requires a DSU, a large enclosed combustor with ceramic refractory, blowers and fans to both pull the displaced vapors through the facility VCS and sustain proper combustion control in the VCU, and a reliable, plentiful fuel source for pilot fuel and assist gas. When the space, height of the stack (and residence time), power, and fuel requirements are available at an onshore marine terminal, VCUs can achieve VOC control of 95 to 99% of captured vapors.[57]

[57] 95% control required by NESHAP Subpart Y at 40 CFR § 63.562(b)(4).

Figure 5-1. Example Vapor Combustion System[58]



Flares are also a common combustion control device used in the "process vent or stack discharges" source classification. Flares require the same vapor capture components as a VCU (i.e., DSU and blowers/fans), as well as supplemental fuel supply. Combustion occurs at the tip of the stack, which is exposed to atmospheric disturbances and precipitation. Therefore, a flare has less residence time and control of combustion temperature in comparison to a VCU. The result is a control efficiency that is typically 95 to 98% control of captured vapors when rich enough to sustain combustion. As well, flares require operations that maintain tip velocity and a vapor stream with a net heating value of at least 270 Btu/scf.[59] As discussed for VCUs, the displaced vapors occurring during a majority of the loading time (~85% of full capacity) of marine vessels with crude oil will not sustain combustion. Supplemental fuel will also be required to sustain complete combustion in a flare. Without the insulation and radiative heating from an enclosed combustor, a flare will require more supplemental fuel and/or sustain lower VOC destruction efficiency.

In addition to sufficient space for installation of the required components, flares also require sufficient space for safe operation in consideration of the thermal radiation from the exposed flame.

[58] https://www.johnzinkhamworthy.com/wp-content/uploads/vapor-combustion-systems.pdf

[59] AP-42, Chapter 13.5 Industrial Flares,02/18.

5.5.2.2 Vapor Recovery Control

Vapor recovery requires the same vapor capture system discussed in the vapor combustion control section, but instead of using a combustor to oxidize the captured hydrocarbons, a vapor recovery unit (VRU) uses one of the following control practices to recover the hydrocarbon as liquid:

- Refrigeration
  - Condense hydrocarbons out of the vapor stream by reducing the temperature below the dewpoint
  - Most effective on vapor-rich streams with low volumetric flow
  - Require significant energy for refrigeration cycle
  - Require storage tank for collection of recovered hydrocarbon liquids
- Adsorption
  - Adsorb hydrocarbons with use of activated carbon (or similar)
  - Require controlled temperature and pressure for effectiveness and safety
  - Carbon replacement requires frequent supply vessel trips and carbon changeout
- Absorption/Adsorption
  - Adsorb hydrocarbons with use of activated carbon (or similar)
  - Utilize two-stage vacuum system to regenerate one carbon bed while alternate carbon bed is controlling the vapor stream
  - Require controlled temperature and pressure for effectiveness and safety
  - Regeneration requires additional equipment including an absorption column and storage tank for lean oil recovered
  - Supply vessels for recovered lean oil or an additional subsea pipeline system would be required to pump lean oil to marine vessels

VRUs can achieve 95 to 99% control, similar to a VCU. A VRU also would require the addition of a completely new platform to house the equipment. Fuel for assist gas would not be required, but the VRU requires significant electrical power (in addition to the vapor blower). Accordingly, a diesel generator would be required. Storage tanks would be necessary for liquids recovered from the vapor stream, and frequent carbon replenishment would necessitate supply boats and added material consumption/waste.

5.5.2.3 Vapor Balancing

Vapor balancing is a passive measure for vapor capture, and potentially subsequent control of loading emissions. Displaced vapors are simply transferred to another tank or vessel, to subsequently be processed or combusted. While simple, it requires a storage tank with vapor space, or an idle vessel serving as a floating storage tank.

5.5.2.4 Vapor Control System Onboard VLCC

Countries engaged in crude oil loading from production platforms in the North Sea developed requirements for control of VOC emissions that initially required 78% reduction in VOCs from loading marine vessels. Purpose-built shuttle tankers operating in the North Sea were modified to have vapor recovery systems onboard. Recovered hydrocarbons are then bunkered and may be used as fuel for the onboard boilers or engines. The recovery of hydrocarbons requires additional safety consideration for the vessel, as well as customization to add the system on the deck.[60]

[60] International Maritime Organization, "Technical Information on Systems and Operations to Assist Development of VOC Management Plans," July 27, 2009 (MEPC.1/Circ. 680).

Figure 5-2. Vapor Recovery Onboard a North Sea Shuttle Tanker

5.5.2.5 Vapor Control System Onboard Support Vessel

Barges have been used in the past to capture and control vapor displaced when loading vessels. The Barge Jovalan and Barge Olympic Spirit have been used at the Ellwood Marine Terminal (no longer in operation), and the Barge San Pedro was utilized at El Segundo Marine Terminal, both in California. Both of these since-retired barges operated near shore, and at much lower loading rates.

For BMOP's proposed DWP, a purpose-built dynamically positioned (DP) vessel would be needed to serve as a floating VRU. BMOP has researched purpose-built vessels and no vessels have been identified that are capable of controlling 80,000 bbl/hr. The highest identified loading rate is 65,000 bbl/hr, on an ~85 meter (almost 300 feet) long ship. The DP vessel would require diesel engine drives and a diesel generator, operating continuously while in service. Further, the DP vessel would introduce another large vessel, but at a different size and draft from the VLCCs and other crude carriers.

A critical design of the DWP is the ability for crude carriers to weathervane and rotate around the CALM buoy to safely load in changing weather (e.g., change in wind direction and currents). A VLCC has a dead weight tonnage (DWT) of 200,000 to 320,000 tons, and is approximately 330 meters (~1,000 feet) in Length Overall (LOA), with a draft up to 29 meters (~95 feet). A vessel of this size will react differently to Meteorological and Oceanographic (MetOcean) conditions than an 85-meter DP vessel. Further, as the crude oil carrier is loaded, the draft will increase. Ocean currents will become a stronger influence over the wind as the load continues and is expected to become the determining factor in the crude carrier's heading (weathervaning). The shallower draft DP vessel will be expected to have a stronger influence from the wind, which could result in differences in the relative headings of the 2 vessels, creating a possible conflict of differing state. With a DP vessel position mid-ship of the crude oil carrier to support vapor capture and recovery, it is particularly susceptible to conflicts due to wind and sea state conditions. The DP will have the ability to change relative location (with diesel engine drives) and could shift to the stern of the crude carrier or to the CALM buoy. Each location will provide advantages and disadvantages, and all will be dynamically affected by MetOcean conditions throughout the loading process.

Adding a large vessel in the same space as a crude carrier as large as a VLCC in the changing MetOcean conditions ~80 miles offshore adds significant operating variables that impact the safety and reliability of the DWP and at a customized size never before built.

BMOP has evaluated expected allowable operating MetOcean conditions for a purpose-built DP vessel. It is estimated that seas in excess of five feet significant wave will potentially cause the operation to be halted based on safety and environmental concerns for the DP vessel. Based on a review of the MetOcean conditions specific to WC509, a DP vessel would result in ~1,720 hours/year of downtime compared to a platform-based vapor control.

5.5.2.6 Submerged Fill and VOC BMP

Submerged fill loading reduces splashing while still allowing for fast loading times in an effort to minimize surface area and total evaporation over time, to minimize VOC emissions throughout the loading event. In prior rulemaking, such as 40 CFR 63 Subpart Y, the EPA has identified that submerged fill can reduce emissions by 60%.

> *Submerged fill reduces the amount of emissions generated from the loading of vessels by reducing turbulence and misting. Use of this technique results in a 60-percent reduction in emissions compared to splash loading.*[61]

A best management practice that promotes coordination with the vessel for loading activities will also minimize the total loading time while loading safely.

5.5.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

5.5.3.1 Vapor Combustion Control

In comparison to a VCU, a flare has the same vapor capture system requirements, similar space requirements, and additional non-air quality environmental, energy, and safety impacts with lower control efficiency. Therefore, BMOP has evaluated a hypothetical vapor combustion control technology utilizing a VCU, because of its additional effectiveness, for the proposed Project.

A VCU control applied to the proposed Project would use floating vapor hoses (~1,500 feet long) to connect the VLCC to the CALM buoys, similar to the crude oil loading hoses, but for vapor return. The vapor hoses would be connected to the VLCC's vapor system to capture displaced vapors, instead of having displaced vapors released through the vent mast riser. The CALM buoys would have to be modified to accommodate the additional vapor line with an additional swivel path, and subsea vapor hoses connecting to PLEMs on the sea floor would have to be constructed with under-buoy vapor hoses (~200 feet). A looped subsea vapor pipeline (~6,000 feet to each buoy) would have to return the captured vapors to a new platform, where risers (~250 feet) would bring the captured vapor to a safety skid with detonation arresters, and then to three marine VCUs. There are few instances of subsea vapor pipelines utilized at nearshore berths to return collected vapors to shore. However, no subsea vapor pipelines have been demonstrated in operation at the

[61] 75 FR 65115, October 21, 2010, right column

water depth, distance, and vertical return up a riser to an offshore pipeline, as would be required for the proposed Project.

BMOP has spent considerable effort designing and evaluating a vapor capture and control system to meet EPA's September 13, 2022 request. The vapor capture system will route captured vapors during loading of a crude oil carrier back to the WC509 Platform Complex. BMOP has re-designed the entire platform complex to accommodate VCU control equipment. The re-design requires the following:

- Addition of vapor capture and pipeline system.
- Re-design of the WC509 Platform Complex.
  - Complete removal of all existing equipment to make space and remove weight.
  - Raising the cellar deck of WC509A to make it even with WC509B and create more physical space for equipment.
  - VCU stacks of limited height to minimize the wind loading on the platform and maintain strength and fatigue criteria. The height of the VCU stack is directly related to the emissions performance and DRE achievability. The BMOP VCU design can achieve 95% DRE during routine operations.
  - Addition of a low pressure flare, to which vapors are directed during vapor line pigging.
- Pending: Assistant Commandant for Marine Safety, Security, and Environmental Protection of the United States Coast Guard to grant an exemption from the distance requirements for the safety devices under 33 CFR 154 Subpart P for approval of a custom DSU for safe operation of the vapor capture and control system in the offshore setting with >1 mile of vapor line distance. [62]
- Sufficient natural gas assist gas with a supply path from Sea Robin, should Stingray's existing supply reduce below minimum needs.
  - Addition of a high pressure flare for natural gas pipeline pigging (anticipated once every seven years).
- Revised DWP Operations.
  - Updated vessel loading schedule to accommodate vapor connections, disconnections, and vapor line pigging.
  - Pending: U.S. Environmental Protection Agency approval of the "maintenance allowance" request included in Appendix E of this application, per 40 CFR § 63.562(b)(6).

With these Project design updates (and pending approval of the custom DSU), vapor capture and control with a VCU is technically feasible during routine loading operations.

5.5.3.2 Vapor Recovery Control

Vapor recovery, or VRU, requires additional real estate that is not available at the WC509 Platform Complex. A VRU would necessitate additional space – on an entirely new platform. A new platform is outside the Purpose of BMOP and would be a re-design of the Project.

5.5.3.2.1 VRU Control at Gaviota is Not Demonstrated in Practice for the Project's Purpose

BMOP has reviewed historical documents regarding a temporary loading operation in California in the mid-1990s that applied vapor capture and control with VRU to loading marine vessels with crude oil, referred to as the "Gaviota Interim Marine Terminal."

The Gaviota Interim Marine Terminal was driven by a need for company-owned stranded assets and huge project costs to find a temporary solution until the long-term project purpose could be realized. Based on

[62] 33 CFR §154.2000(h).

its near-shore location with access to extensive onshore equipment and internal floating roof tanks, lower loading rates, and temporary business need, a vapor recovery system was temporarily operated at the Gaviota Interim Marine Terminal Such a vapor recovery system cannot be applied at BMOP because it lacks these attributes and such a system does not meet the Project purpose. The Gaviota Interim Marine Terminal does not confirm that long-term feasibility, reliability, or operability of controls is demonstrated for BMOP's unique Project purpose.

A VRU would not meet explicit USCG safety requirements and would significantly affect the reliability of the Project. Accordingly, a VRU requirement would redefine the source, and can be rejected from consideration in the top-down BACT analysis.

5.5.3.3 Vapor Balancing

The Marine Board identified the practical limitations of vapor balancing.

> *The technique known as vapor balancing can be used as an adjunct to vapor control to reduce instantaneous processing rates, or for other reasons. For example, at Exxon's offshore Hondo Field in California, loading emissions are pumped into a large tank vessel where they are retained for subsequent burning. The vessel acts as a buffer, permitting loading rates higher than could otherwise be accommodated by the vapor treatment facilities at the site. Vapors are drawn from the holding tanks at a constant rate, not dependent on instantaneous loading rates.*
>
> *But vapor balancing should not be regarded as a standard procedure. The roofs of many modern storage tanks are designed to float on the surface of the liquid, leaving no space for vapors. There may be applications for vapor balancing at specific sites.*[63]

BMOP does not fit the very specific criteria where vapor balancing would be a practical control, as it adds the need for a very large vapor storage vessel with the capacity to store displaced vapors from loading VLCCs at up to 80,000 bbl/hr. Furthermore, a vapor storage vessel would not provide the ability to control the emissions – just a temporary storage vessel to hold the displaced vapors. A VCU platform or other control system would still be needed, with the added complication of a storage vessel. Vapor balancing is not a technically feasible control for the proposed Project.

5.5.3.4 Vapor Control System Onboard VLCC

Shuttle tankers are not the same as typical crude carriers, as they are designed and built for a specific purpose – to carry produced oil a short distance to a processing plant. Shuttle tankers are used when the depth or sea conditions of an offshore production area make pipelines to shore economically undesirable.

Shuttle tankers are designed for the North Sea environment and loading from production platforms or floating production, storage & offtake vessels (FPSO). The shuttle tankers are equipped with a bow loading system or a submerged turret loading system. They are equipped with dynamic positioning systems, which include azimuth and tunnel thrusters both forward and aft. North Sea shuttles also have twin-screw propulsion system for redundancy and dynamic positioning. Shuttle tankers also typically have large ballast

[63] Marine Board, National Research Council, "Controlling Hydrocarbon Emissions from Tank Vessel Loading," 1987, page 80. (Docket A-90-44, II-I-4)

tank volume to help with stability and positioning at the sacrifice of cargo-carrying efficiency. North Sea shuttle tankers have a capacity of less than half of a VLCC (<850,000 bbls).

Shuttle tankers are alternatives to pipelines and serve as short-run transport between limited receipt points and delivery points. The loading and discharging frequency are comparatively high, with less time in transit (up to 50 loads per year). Some shuttle tankers spend 50% of their life in loading mode in the field.[64] This high frequency of loading of produced oil (not weathered crude from a terminal) provides additional benefit for onboard recovery. In comparison, the VLCCs expected to call at the BMOP DWP will traverse the globe and will have longer hauls with fewer annual loading events. Thus, VLCCs are designed for efficiency of transit – and the larger size of their cargo is critical for this efficiency.

BMOP does not own VLCCs or other crude carrying vessels. The purpose of the project is to serve the existing fleet of international ships for export based on market conditions, not a purpose-built shuttle from the DWP to a few nearby delivery points. A shuttle tanker does not meet the purpose of the project and cannot feasibly be implemented by BMOP as a single terminal in the international commodity market.

For the BMOP project, control technology applied to marine loading terminals that interrupt the Project purpose of a safe and reliable long-term supply of **crude oil export for the global market** redefines the source, just as applying less reliable electricity generation redefines the source for *City of Palmdale*. Vapor control systems onboard VLCCs would redefine the source and are not a technically feasible control for the proposed Project.

5.5.3.5 Vapor Control System Onboard Support Vessel

The following operational constraints do not allow for application of vapor control systems onboard VLCCs to BMOP:

- Loading Rate Limits. Barges with onboard vapor control limit the loading capacity significantly. The largest of the identified barges that have employed vapor control, the Barge San Pedro, had a maximum loading rate of 15,000 bbl/hr (Ellwood Marine Terminal was limited to a loading rate of 4,200 bbl/hr). This would not conform to the Project purpose, as it would take almost a week to fully load a VLCC. The largest purpose-built DP vessel that could be customized with onboard vapor control is limited to 65,000 bbl/hr. This remains below the capacity of BMOP.
- VOC Control Limits. The Barge San Pedro was only capable of accommodating gas-free tankers prior to loading – a unique requirement to El Segundo. The carbon canister capacity of the barge would be exceeded if not gas-free, even for vessels with 20% of the capacity of the VLCCs to be accommodated at BMOP. This would require frequent interruption in loading to change out carbon canisters. The refrigeration design of the Barges Jovalan (56,000 bbl capacity) and Olympic Spirit (80,360 bbl capacity) was an onboard recovery with return to the barge storage capacity (more than 25 times smaller than a VLCC).
- Sea State Limits. The onboard vapor recovery has only been utilized at fixed berth locations near shore in partially-protected coastal waters (Ellwood Marine Terminal was ~0.5 miles offshore Goleta, California in a water depth of 60 feet). This allows for a fendered barge to safely approach the port side of a moored vessel in a fixed position. In the exposed waters of the open ocean with more extreme weather, requiring a vessel to approach and remain tandem to the starboard or port side of a vessel free to weathervane introduces safety risks and further limits the permissible sea state conditions for operations. A smaller barge will react differently than a large VLCC from the impact of wind (size of

[64] https://www.dnvgl.com/expert-story/maritime-impact/Shuttle-tankers-safe-flexible-efficient.html

vessel) and current (draft). Operations will therefore be dependent on restricted sea states and weather to ensure that a barge can safely approach and operate immediately adjacent to the VLCC.

The barges and purpose-built DP vessels evaluated utilized carbon canisters and refrigeration. Other vapor recovery technologies on barges have been considered and rejected because of the significant equipment size. Chevron has previously noted other vapor recovery technology "is not practicable because the equipment is too large to be installed on a workboat or barge."[65]

Vapor control systems onboard a support vessel are not a technically feasible control for the proposed Project and would redefine the source to a slower loading rate, significantly reduced operations, and less safety and reliability – all critical to the Projects' Purpose.

5.5.3.6 Submerged Fill and VOC BMP

Submerged fill is common among marine vessels and required by the U.S. Coast Guard (USCG) at 46 CFR §153.282.

> *The Commenter noted that submerged fill, as defined by the Coast Guard, has been standard industry practice for some time, reduces HAP emissions, and eliminates static electricity from free-falling cargo, thereby enhancing operational safety.*[66]

Best management practice ensures submerged fill loading and consideration of the vessel's VOC management plan meeting the International Maritime Organization's requirements of MEPC.185(59).

Loading by submerged fill and following best management practices is technically feasible for the Project.

5.5.4 Rank of Remaining Control Technologies (Step 3)

Table 5-1. Rank of Remaining VOC Control Technologies for Marine Loading

Control	Efficiency	Rank
Vapor Combustion Control	95 - 99%	1
Submerged Fill and VOC BMP	60%	2

5.5.5 Evaluation of Most Stringent Control Technologies (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This step has been performed for each remaining control technology to consider economic, energy, and/or environmental considerations, and is described in this section. In this step, once an option is selected, no further (i.e., lower ranking) options are assessed.

[65] Letter from J.D. Bellows, Chevron Corporation, to Mr. David W. Markwordt, U.S. EPA, "Technical Choices for Marine Vapor Controls on Loading Operations at Offshore Terminals, July 21, 1993, IV-D-136 of Docket A-90-44.

[66] 76 FR 22581, April 21, 2011, left column.

With this resubmittal of the PSD application, BMOP now includes a vapor capture and VCU control system during routine operations, and submerged fill at all times, including during the vapor control "maintenance allowance" as identified in Appendix E of this application.

Environmental Impacts

The use of vapor capture and control with VCUs results in environmental impacts from the combustion of displaced vapors, as well as fuel for the VCU pilot and assist gas necessary to sustain temperature in the VCU for interted vessels. The by-products of combustion from VCUs added to the BMOP project result in the following additional potential emissions, not otherwise emitted.

Table 5-2. Added Emissions as a Result of the VCU Control of Marine Loading

	NO_X (tpy)	CO (tpy)	SO_2 (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	CO_2e (tpy)
Marine Vapor Combustion Units						
MVCU1	143	263	4.25	4.99	4.99	157,510
MVCU2	143	263	4.25	4.99	4.99	157,510
MVCU3	143	263	4.25	4.99	4.99	157,510
Total	430	790	12.8	15.0	15.0	472,531

As a result of the VCU controls, the BMOP Project becomes a major modification for NO_X, CO, PM_{10}, $PM_{2.5}$, and GHG. Without the VCU controls, the BMOP Project would be major for VOC, only.

Further, the vapor capture system will result in secondary emissions from longer loading schedules of each crude oil carrier, and more marine support vessel activities (e.g., support tug operations to lift, support connections and disconnections, and drain floating vapor hoses. Pigging of the vapor return pipelines will also result in the byproducts of combustion.

Energy Impacts

The pilot fuel and assist gas requirements for VCUs will consume additional natural gas, not otherwise required. Further, the power requirements for the vapor capture blowers and additional control equipment will require the generation of additional electricity, consuming additional fuel at the platform to provide this power. To ensure sufficient natural gas supply at the WC 509 Platform Complex for the VCU control option, natural gas supply from the existing Stingray system and the Sea Robin system will be required (the Stingray system is not projected to provide sufficient natural gas for VCUs over the life of the Project).

The economic, environmental, and energy impacts of a vapor capture and VCU control system would not preclude the use of this control option based on EPA's September 13, 2022 letter that NESHAP Subpart Y is applicable to BMOP. The use of vapor capture and VCU control is the only feasible option available for the BMOP Project to meet the control level required by Subpart Y.

5.5.6 Selection of BACT (Step 5)

With the assumption that the two pending approvals are granted: (1) approval of the custom DSU by the United States Coast Guard, and (2) approval of the maintenance allowance in Appendix E of this application by the Environmental Protection Agency, BMOP proposes the utilization of three (3) VCUs to achieve 95% VOC control efficiency as VOC BACT during routine loading operations. Compliance with the proposed BACT

will be demonstrated by following the explicit requirements of 40 CFR 63 Subpart Y including the maintenance allowance. In addition, BMOP shall be limited to loading only crude oil via submerged fill with a maximum TVP of 10.99 psia, at a maximum throughput of 80,000 bbl/hr.

Compliance assurance will be provided in accordance with the requirements of NESHAP Subpart Y, detailed in Section 4.2.1.2.4 of this application.

5.6 VOC BACT – Large Non-Emergency Natural Gas Fired Generators

5.6.1 Background on Pollutant Formation

For natural gas-fired reciprocating engines, VOC emissions result from incomplete combustion. In natural gas combustion, some organics are carried over unreacted while others are most likely pyrolysis products of the heavier hydrocarbon fuel constituents. Partially burned hydrocarbons can occur because of incorrect air/fuel ratios in the cylinder during compression due to maladjustment of the engine fuel system. Finally, partially burned hydrocarbons can also occur in reciprocating engines due to low cylinder temperature via excessive cooling through the cylinder walls, or early cooling of the gases by expansion of the combustion volume induced by premature piston motion. [67]

While CI engines inherently operate lean, spark ignition (i.e. natural gas engines) can operate in rich or lean modes of operation based on the combustion model used in the design. The primary distinction between the two is the amount of excess air admitted prior to combustion. Rich-burn engines operate with a minimum amount of air required for combustion and lean-burn engines use 50% to 100% more air than is necessary for combustion.

Natural gas-fired reciprocating engines are separated into three design classes: 2-cycle (stroke) lean-burn, 4-stroke lean-burn, and 4-stroke rich-burn. Two-stroke engines complete the power cycle in a single crankshaft revolution as compared to the two crankshaft revolutions required for 4-stroke engines.

5.6.2 Identification of Potential Control Technologies (Step 1)

The proposed project involves two (2) 1,736 kW (~2,328 hp) large non-emergency natural gas-fired 4-stroke lean-burn generator engines. The RICEs will be subject to NSPS Subpart JJJJ and NESHAP Subpart ZZZZ requirements as identified in Section 4 above. Per NSPS Subpart JJJJ, the regulations require the purchase of a RICE certified to the applicable Tier standards or the conduct of performance testing to demonstrate compliance with emission limits, whereas NESHAP ZZZZ requires the engines to reduce CO emissions or alternatively formaldehyde emissions. These standards and accompanying requirements are taken as the baseline for this BACT analysis.

Available VOC emissions control options for lean-burn spark ignition (SI), RICE include:

- Combustion Control - Good combustion practices (GCP); and
- Post-Combustion Control - Oxidation catalyst.

[67] AP-42 Section 3.2.3 (7/00)

5.6.2.1 Good Combustion Practices

GCP involve parametric monitoring and controlling the operating parameters of the reciprocating engine to ensure the unit continually operates as close to optimum (i.e., minimum emission) conditions as practicable. Control of combustion temperature is the principal focus of combustion process control in natural gas-fired engines. Combustion control requires tradeoffs – higher temperatures favor complete consumption of the fuel and lower residual hydrocarbons (HC) and CO but result in increased NO_X formation. Lean combustion dilutes the fuel mixture and reduces combustion temperatures and therefore reduces NO_X formation. This allows a higher compression ratio or peak firing pressures resulting in higher efficiency. However, if the mixture is too lean, misfiring and incomplete combustion may occur, increasing CO and VOC emissions.[68]

5.6.2.2 Oxidation Catalyst

Oxidation catalysts consist of a substrate made up of thousands of small channels. Each channel is coated with a highly porous layer containing precious metal catalysts, such as platinum or palladium. As exhaust gas travels down the channel, HC and CO react with oxygen within the porous catalyst layer to form carbon dioxide (CO_2) and water. The resulting gases then exit the channels and flow through the rest of the exhaust system. The effectiveness of the control varies for different species of HC. The control requires sufficient exhaust temperature above 700°F.

5.6.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

5.6.3.1 Good Combustion Practices

GCP allow equipment to operate as efficiently as possible to maintain optimal emission release conditions from the unit. This is considered technically feasible for the control of VOC emissions from the engines.

5.6.3.2 Oxidation Catalyst

A review of EPA's RBLC database shows that oxidation catalysts have been employed as BACT for the control of VOC emissions for engines. BACT emission limits for units controlled by oxidation catalyst range from ~0.2 g/hp-hr to 0.5 g/hp-hr, according to the RBLC search results, included in Appendix D to this application.

5.6.4 Rank of Remaining Control Technologies (Step 3)

The more effective control option from steps 1 and 2 is oxidation catalyst, which can achieve between 30 and 50% control for total VOC, followed by GCP.

5.6.5 Evaluation of Most Stringent Control Technologies (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This step has been performed for each remaining control technology

[68] Technical Report: Technology Characterization: Reciprocating Engines, March 2015, Prepared by Darrow, K. *et al* of ICF International on Behalf of EPA and US DOE.

based on economic, energy, and environmental considerations, and is described in this section. In this step, once an option is selected, no further (i.e., lower ranking) options are assessed.

The use of oxidation catalyst reduces the effective power output of RICE and results in a solid waste stream. GCP is part of normal practice for engines so no cost is associated with that option.

5.6.6 Selection of BACT (Step 5)

BMOP proposes a VOC BACT emission limit using the oxidation catalysts and GCP consistent with the NSPS Subpart JJJJ VOC emission limit of 0.3 g/hp-hr for the natural-gas fired generators. BMOP will demonstrate compliance with the VOC BACT consistent with the testing requirements of 40 CFR §60.4244 and Table 2 to Subpart JJJJ of Part 60.

At all times, BMOP will maintain the generators and oxidation catalysts in a manner consistent with safety and good air pollution control practices for minimizing emissions per 40 CFR §63.6605. BMOP will ensure proper maintenance of the catalyst such that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test. In addition, BMOP will maintain the temperature of the engine's exhaust so that the catalyst inlet temperature is greater than or equal to 450°F and less than or equal to 1,350°F, consistent with 40 CFR §63.6600(b) and Table 2b Subpart ZZZZ of Part 63. BMOP will install, operate, and maintain a temperature CPMS that meets the requirements of §63.6625(b) to continuously collect temperature data. In instances where the catalyst is changed, BMOP will reestablish the values of the operating parameters measured during the initial performance test and conduct a performance test to demonstrate that the engines are meeting the required emission limitations.

Because the oxidation catalyst is effective only at hot exhaust temperatures (>700°F), the use of GCP and clean fuels will be the BACT work practice standards during startup to control VOC emissions.

5.7 VOC BACT – Large Emergency Diesel Firewater Pump

5.7.1 Background on Pollutant Formation

The pollutants commonly classified as hydrocarbons are composed of a wide variety of organic compounds and are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. Most unburned hydrocarbon emissions result from fuel droplets that were transported or injected into the quench layer during combustion. This is the region immediately adjacent to the combustion chamber surfaces, where heat transfer outward through the cylinder walls causes the mixture temperatures to be too low to support combustion. Partially burned hydrocarbons can occur because of poor air and fuel homogeneity due to incomplete mixing, before or during combustion; incorrect air/fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system; excessively large fuel droplets (diesel engines); and low cylinder temperature due to excessive cooling (quenching) through the walls or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed. [69]

Most of the pollutants from diesel engines are emitted through the exhaust. However, some total organic compounds (TOC) escape from the crankcase as a result of blowby (gases that are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank and carburetor

[69] AP-42 Section 3.4.3 (10/96)

because of evaporation. Evaporative losses are insignificant in diesel engines due to the low volatility of diesel fuels. [70]

5.7.2 Identification of Potential Control Technologies (Step 1)

The proposed project involves two (2) 485 kW (~650 hp) large emergency diesel firewater pumps. The RICEs will be subject to NSPS Subpart IIII and NESHAP Subpart ZZZZ[71]. These regulations require purchasing RICEs certified to applicable Tier standards, combusting only ultra-low sulfur diesel, and various monitoring, recordkeeping, and reporting requirements. The engines will be subject to the emission standards which are established for nonroad engines in 40 CFR §89 and Table 4 of NSPS Subpart IIII, respectively. These standards and accompanying requirements are taken as the floor for this BACT analysis.

Available VOC emissions control options for diesel-fired CI, RICE include:

- Combustion Control - GCP; and
- Post-Combustion Control - Oxidation catalyst, or, more specifically, diesel oxidation catalyst (DOC).

5.7.2.1 Good Combustion Practices

GCP for CI RICE for VOC control consists of minimizing startup and idling time. This is achieved in normal practice for emergency-use engines that, by design, only operate for maintenance purposes, readiness testing, and during emergency events.

5.7.2.2 Oxidation Catalyst

DOC utilizes a catalyst such as platinum or palladium to further oxidize the engine's exhaust, which includes HC, e.g., VOC, and converts it to CO_2 and water. Use of DOC can result in up to 90 percent reduction in some HC/VOC species.[72] However, for emergency-use or intermittent-use engines, "[b]ecause these engines are typically used only a few number of hours per year…[s]uch engines rarely if ever use the [DOC] type of emission controls."[73] Queries of the RBLC reveal no installations of DOC on emergency, diesel-fired engines or on nonroad, diesel-fired engines (see Appendix D of this application). DOC is nonetheless carried forward in this BACT analysis.

5.7.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

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[70] Ibid.

[71] Per 40 CFR §63.6600(c), the emergency diesel generator does not need to comply with emissions limitations or operating limits in NESHAP Subpart ZZZZ.

[72] EPA, *Alternative Control Techniques Document: Stationary Diesel Engines*, March 5, 2010, p. 41. (https://www.epa.gov/sites/production/files/2014-02/documents/3_2010_diesel_eng_alternativecontrol.pdf)

[73] EPA, Memorandum: *Response to Public Comments on Proposed National Emission Standards for Hazardous Air Pollutants for Existing Stationary Reciprocating Internal Combustion Engines Located at Area Sources of Hazardous Air Pollutant Emissions or Have a Site Rating Less Than or Equal to 500 Brake HP Located at Major Sources of Hazardous Air Pollutant Emissions*, August 10, 2010, p. 172-173. (EPA-HQ-OAR-2008-0708)

Both control options identified in step 1 are technically feasible.

5.7.4 Rank of Remaining Control Technologies (Step 3)

The more effective control option from steps 1 and 2 is DOC, which can theoretically achieve up to 90 percent reduction of certain VOC species. [74] GCP is a part of normal practice for emergency-use engines so no additional VOC reduction can be attributed.

5.7.5 Evaluation of Most Stringent Control Technologies (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This step has been performed for each remaining control technology based on economic, energy, and environmental considerations, and is described in this section. In this step, once an option is selected, no further (i.e., lower ranking) options are assessed.

The use of DOC reduces the effective power output of RICE and results in a solid waste stream. GCP is part of normal practice for emergency-use engines so no cost is associated with that option.

In its 2010 MACT/GACT evaluation for engines, EPA concluded for emergency engines: "Because these engines are typically used only a few number of hours per year [(27 hours per year per NFPA codes)], the costs of emission control are not warranted when compared to the emission reductions that would be achieved."[75] Based on EPA's assessment and the fact that the RBLC contains no records of DOC installation on emergency-use or nonroad engines, DOC is eliminated from consideration as BACT.

5.7.6 Selection of BACT (Step 5)

The remaining control option, GCP, is selected as BACT for the two (2) 485 kW (~650 hp) large emergency diesel engines. As stated above, GCP for emergency engines is normal practice. Maintenance checks and readiness testing will be limited to 100 hours per year in accordance with 40 CFR §63.6640(f), not including operation during emergencies. The Project will ensure that the engines are operated only when needed for intermittent purposes. GCP will allow the engines to meet the VOC emission limit in NSPS Subpart IIII of 4.0 g/kW-hr (3.0 g/bhp-hr) for NMHC + NO_X, respectively. BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet these emission limits, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of the engines in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.8 VOC BACT – Small Emergency Diesel Generator

5.8.1 Background on Pollutant Formation

The pollutants commonly classified as hydrocarbons are composed of a wide variety of organic compounds and are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. Most unburned hydrocarbon emissions result from fuel droplets that were transported or injected into the quench layer during combustion. This is the region immediately adjacent to

[74] EPA, *Alternative Control Techniques Document: Stationary Diesel Engines*, March 5, 2010, p. 41. (https://www.epa.gov/sites/production/files/2014-02/documents/3_2010_diesel_eng_alternativecontrol.pdf)

[75] Ibid.

the combustion chamber surfaces, where heat transfer outward through the cylinder walls causes the mixture temperatures to be too low to support combustion. Partially burned hydrocarbons can occur because of poor air and fuel homogeneity due to incomplete mixing, before or during combustion; incorrect air/fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system; excessively large fuel droplets (diesel engines); and low cylinder temperature due to excessive cooling (quenching) through the walls or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed. [76]

Most of the pollutants from diesel engines are emitted through the exhaust. However, some TOCs escape from the crankcase as a result of blowby (gases that are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank and carburetor because of evaporation. Evaporative losses are insignificant in diesel engines due to the low volatility of diesel fuels. [77]

5.8.2 Identification of Potential Control Technologies (Step 1)

The proposed project involves one (1) ~336 kW (450 hp) emergency diesel generator. The RICE will be subject to NSPS Subpart IIII and NESHAP Subpart ZZZZ. These regulations require purchasing RICEs certified to applicable Tier standards, combusting only ultra-low sulfur diesel, and various monitoring, recordkeeping, and reporting requirements. The engines will be subject to the emission standards which are established for nonroad engines in 40 CFR §89 and Table 4 of NSPS Subpart IIII, respectively. These standards and accompanying requirements are taken as the floor for this BACT analysis.

The following CO control technologies have been identified:

- Combustion Control - GCP; and
- Post-Combustion Control - Oxidation catalyst, or, more specifically, diesel oxidation catalyst (DOC).

5.8.2.1 Good Combustion Practices

A detailed description of this control technology is provided in Section 5.7.2.

5.8.2.2 Oxidation Catalyst

A detailed description of this control technology is provided in Section 5.7.2.

5.8.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

The use of DOC reduces the effective power output of RICE and results in a solid waste stream. GCP is part of normal practice for emergency-use engines so no cost is associated with that option. Both control options are technically feasible.

[76] AP-42 Section 3.3.3 (10/96)

[77] Ibid

5.8.4 Rank of Remaining Control Technologies (Step 3)

The more effective control option from steps 1 and 2 is DOC, which can theoretically achieve up to 90 percent reduction of certain VOC species. [78] GCP is a part of normal practice for emergency-use engines so no additional VOC reduction can be attributed.

5.8.5 Evaluation of Most Stringent Control Technologies (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This step has been performed for each remaining control technology based on economic, energy, and environmental considerations, and is described in this section. In this step, once an option is selected, no further (i.e., lower ranking) options are assessed.

5.8.5.1 Good Combustion Practices

Good combustion practices are an inherent part of engine use, so no additional costs or impacts are associated with their use.

5.8.5.2 Oxidation Catalyst

The use of DOC reduces the effective power output of RICE and results in a solid waste stream. GCP is part of normal practice for emergency-use engines so no cost is associated with that option.

In its 2010 MACT/GACT evaluation for engines, EPA concluded for emergency engines: "Because these engines are typically used only a few number of hours per year [(27 hours per year per NFPA codes)], the costs of emission control are not warranted when compared to the emission reductions that would be achieved."[79] Based on EPA's assessment and the fact that the RBLC contains no records of DOC installation on emergency-use or nonroad engines, DOC is eliminated from consideration as BACT.

5.8.6 Selection of BACT (Step 5)

The remaining control option, GCP, is selected as BACT for the one (1) 336 kW (~450 hp) small emergency diesel engine. As stated above, GCP for emergency engines is normal practice. Maintenance checks and readiness testing will be limited to 100 hours per year in accordance with 40 CFR §63.6640(f), not including operation during emergencies. The Project will ensure that the engines are operated only when needed for intermittent purposes. GCP will allow the engines to meet the VOC emission limit in NSPS Subpart IIII of 4.0 g/kW-hr (3.0 g/bhp-hr). BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet these emission limits, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of the engines in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

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[78] EPA, *Alternative Control Techniques Document: Stationary Diesel Engines*, March 5, 2010, p. 41. (https://www.epa.gov/sites/production/files/2014-02/documents/3_2010_diesel_eng_alternativecontrol.pdf)

[79] Ibid.

5.9 VOC BACT – Small Non-Emergency Diesel Crane Engines

5.9.1 Background on Pollutant Formation

The pollutants commonly classified as hydrocarbons are composed of a wide variety of organic compounds and are discharged into the atmosphere when some of the fuel remains unburned or is only partially burned during the combustion process. Most unburned hydrocarbon emissions result from fuel droplets that were transported or injected into the quench layer during combustion. This is the region immediately adjacent to the combustion chamber surfaces, where heat transfer outward through the cylinder walls causes the mixture temperatures to be too low to support combustion. Partially burned hydrocarbons can occur because of poor air and fuel homogeneity due to incomplete mixing, before or during combustion; incorrect air/fuel ratios in the cylinder during combustion due to maladjustment of the engine fuel system; excessively large fuel droplets (diesel engines); and low cylinder temperature due to excessive cooling (quenching) through the walls or early cooling of the gases by expansion of the combustion volume caused by piston motion before combustion is completed. [80]

Most of the pollutants from diesel engines are emitted through the exhaust. However, some TOCs escape from the crankcase as a result of blowby (gases that are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank and carburetor because of evaporation. Evaporative losses are insignificant in diesel engines due to the low volatility of diesel fuels. [81]

5.9.2 Identification of Potential Control Technologies (Step 1)

The proposed project involves two (2) 354 kW (~475 hp) small non-emergency diesel crane engines. The RICEs will be subject to NSPS Subpart IIII and NESHAP Subpart ZZZZ.[82] These regulations require purchasing RICE certified to applicable tier standards, combusting only ultra-low sulfur diesel, and various monitoring, recordkeeping, and reporting requirements. The engines will be subject to the emission standards in 40 CFR §1039.101 for new and in-use nonroad CI engines. These standards and accompanying requirements are taken as the floor for this BACT analysis.

Available VOC emissions control options for diesel-fired, i.e., CI, RICE include:

- Combustion Control - GCP; and
- Post-Combustion Control - Oxidation catalyst, or, more specifically, DOC.

5.9.2.1 Good Combustion Practices

A detailed description of this control technology is provided in Section 5.7.2.

5.9.2.2 Oxidation Catalyst

A detailed description of this control technology is provided in Section 5.8.2.

[80] AP-42 Section 3.3.3 (10/96)

[81] Ibid

[82] For new RICE with a site rating of less than or equal to 500 hp located at a major HAP source, the only requirement under NESHAP Subpart ZZZZ is to comply with NSPS Subpart IIII per 40 CFR §63.6590(c)(7).

5.9.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

5.9.3.1 Good Combustion Practices

GCP allow equipment to operate as efficiently as possible to maintain optimal emission release conditions from the unit. This is considered technically feasible for the control of VOC emissions from the engines.

5.9.3.2 Oxidation Catalyst

A review of EPA's RBLC database shows that oxidation catalysts have been employed as BACT for the control of VOC emissions for engines. Queries of the RBLC reveal no installations of DOC on small diesel-fired engines or on nonroad, diesel-fired engines (see Appendix D of this application). In addition, the cranes will not require continuous operation. The crane engines will cycle through loads intermittently when in use. The non-continuous operation and intermittent cycling of the engines will lead to varying exhaust temperatures. Because oxidation catalysts require consistently high exhaust temperatures in excess of 700°F, the operating duty of the crane engines will lessen the effectiveness of catalysts, in a similar way as emergency engines.

Both control options identified in step 1 are technically feasible.

5.9.4 Rank of Remaining Control Technologies (Step 3)

The more effective control option from steps 1 and 2 is oxidation catalyst, which can theoretically achieve up to 90 percent reduction of some VOC species. [83] GCP is a part of normal practice for engines so no additional VOC reduction can be attributed.

5.9.5 Evaluation of Most Stringent Control Technologies (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This step has been performed for each remaining control technology based on economic, energy, and environmental considerations, and is described in this section. In this step, once an option is selected, no further (i.e., lower ranking) options are assessed.

The use of oxidation catalyst reduces the effective power output of RICE and results in a solid waste stream. As well, because of the intermittent operation of the cranes and cycling of the engines while in use, the effectiveness of the oxidation catalysts will be limited. In addition to the reduced emissions mitigation, the costs of oxidation catalysts will be economically unreasonable with diminished effectiveness and limited operation.

GCP is part of normal practice for engines so no cost is associated with that option.

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[83] EPA, *Alternative Control Techniques Document: Stationary Diesel Engines*, March 5, 2010, p. 41. (https://www.epa.gov/sites/production/files/2014-02/documents/3_2010_diesel_eng_alternativecontrol.pdf)

5.9.6 Selection of BACT (Step 5)

The remaining control option, GCP, is selected as BACT for the two (2) 354 kW (~475 hp) diesel-fired crane engines. The Project will ensure that the engines are operated only when needed for intermittent purposes, at less than 4,380 hours per year, per engine. GCP will allow the engines to meet the VOC emission limit in NSPS Subpart IIII of 0.29 g/kW-hr. BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet these emission limits, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of the engines to confirm compliance with the operating restriction.

5.10 VOC BACT – Fugitive Emissions

During operation, piping components have the potential to produce fugitive emissions as a result of leaks from: valves, connectors, flanges, pressure relief valves, pump seals, and sampling connections. As discussed in Section 3.2.7., potential fugitive emissions from piping components have been estimated using a conservative SOCMI emissions factor. This factor was chosen to ensure a conservative representation of the collection of piping components in various services such as crude oil, diesel etc., at the WC 509 DWP. It should be noted that no reduction from these average emissions factors has been applied for these estimates.

5.10.1 Identification of Potential Control Technologies (Step 1)

The following available control technologies were identified:[84]

- Installing "leakless technology" piping components;
- Implementing a leak detection and repair (LDAR) program; or
- Implementing an audio/visual/olfactory (AVO) monitoring program.

It should be noted that the only fugitive VOC control technology identified by the RBLC for fugitives at marine loading terminals (Process ID 42.004) was LDAR and AVO monitoring. LDAR was required only as lowest achievable emission rates (LAER), while AVO was the result of a BACT determination.

5.10.2 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

5.10.2.1 Leakless Technology

Leakless technology valves are primarily used in applications with highly toxic or otherwise hazardous materials. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellow valves, if they fail, cannot be repaired without a unit shutdown that often generates additional emissions. Further, it is not accurate to assume that "leakless" components do not leak over the lifetime of the component or that their use would result in zero emissions. In the September 27, 2013 response to Sierra Club's comment letter on draft permit PSD-TX-102982-GHG, ExxonMobil stated that, *"For example, the valve packing configurations noted by the BAAQMD permits for*

[84] http://www.epa.gov/region6/6pd/air/pd-r/ghg/cheniere-corpus-response091713.pdf

refineries noted by the Sierra Club, such as bellow sealed valves and live loaded packed valves do leak. Bellow seals can fail, live load packing wears and leaks, etc."[85] In addition, temperature changes can cause degradation of leakless components, such as bellow valves, which can reduce the useful life of the component. And design of components is subject to good engineering judgment and process safety considerations, which limit use of certain leakless components.

The RBLC review did not identify any BACT or LAER determinations for the use of leakless components at marine loading terminals. Accordingly, leakless components are not a feasible solution for all piping components for the Project.

5.10.2.2 LDAR

Instrument monitoring (using EPA's Method 21, 40 CFR §60, Appendix A-7) is effective for identifying leaking VOC components and controlling VOC emissions at onshore locations. LDAR control efficiency ranges from 40 to 97%, depending on the frequency of monitoring, leak definition, and time for repair.[86]

For an offshore platform, the effectiveness of instruments using Method 21 to identify small leaks is not practical with the unique weather conditions and limited personnel of the proposed Project. Much of the piping components will not be in continuous service or will contain very low vapor pressure liquids (e.g., diesel). Piping for the loading operation will not all be accessible from the manned platform, as some of the piping components will be at the CALM buoys or submerged. For these reasons, LDAR is not considered feasible for the Project.

5.10.2.3 AVO

Leaking fugitive components can be identified through audio, visual, or olfactory (AVO) methods. The gases and process fluids in the piping components must have discernable odor to make them detectable by olfactory means. A significant leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases and fluids, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place at onshore loading terminals.

AVO is considered technically feasible for the Project for accessible components on the manned WC 509 Platform Complex.

5.10.3 Rank of Remaining Control Technologies (Step 3)

AVO is the only control technology remaining.

AVO owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as personnel on the platform make rounds, inspecting equipment during those routine tours of the operating areas. This method cannot generally identify leaks at as low of a leak rate as instrument reading can identify; however, low leak rates have lower potential impacts than do larger leaks. This method, due to the frequency of observation, is effective for identification of larger leaks.

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[85] https://archive.epa.gov/region6/6pd/air/pd-r/ghg/web/pdf/exxonmobil-baytown-olefins-resp2comments.pdf

[86] This is based on emission reductions at refineries that were obtained for various components from EPA's recently collected data for the Uniform Standards (Reference Memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011, EPA-HQ-OAR-2002-0037-0180 as the basis for these reductions).

5.10.4 Evaluation of Most Stringent Control Technologies (Step 4)

As AVO is the only control option remaining, a cost analysis is not required.

5.10.5 Selection of BACT (Step 5)

BMOP proposes the use of AVO monitoring as VOC BACT for fugitive emissions. BMOP will comply with the AVO monitoring as follows:

- During loading, BMOP will conduct AVO checks for leaks once per day during loading operations for the accessible crude oil components on the offshore platform.
  - As an alternative, BMOP may use an optical gas imaging instrument to identify leaks. If used as an alternative to AVO checks, the optical gas instrument must meet the requirements of 40 CFR §60.18(i)(1) and (2).
  - The date and time of each inspection shall be recorded.
- A repair will be attempted for identified leaks as soon as practicable. An initial repair attempt is required within five in-service days (for example, attempt to tighten a bolt or packing gland). If the initial repair attempt is not successful, additional repair attempts should be completed within fifteen in-service days.
  - The date(s) and time(s) of repairs conducted in response to an identified leak shall be recorded.
- Delay of repair of a leaking component is allowed for the following reasons: repair is technically infeasible without a DWP shutdown, a repair within fifteen days would result in emissions or impacts greater than fugitive emissions resulting from the delay of repair, or the unavailability of parts, resources, or repair conditions (i.e., weather) prevent repair within fifteen days. The component should be placed on a "Delay of Repair" list.
  - The component identification and explanation of why the component cannot be repaired immediately shall be recorded. An estimated date for repairing the component must be included in the facility records.
- BMOP will develop a list of difficult-to-monitor and unsafe-to-monitor components.
  - A difficult-to-monitor component is one that cannot be inspected without elevating personnel more than two meters above a permanent support structure or requires a permit for confined space entry as defined in 29 CFR §1910.146, December 1, 1998.
  - An unsafe-to-monitor component is one that BMOP determines is unsafe to monitor because personnel would be exposed to immediate danger as a consequence of conducting the monitoring.

Leak protection is inherent to some of the equipment design at the proposed DWP. For example, the floating hoses used for loading crude oil are designed with elastomeric linings to prevent leaks. The double carcass design of the floating hoses themselves provide a second barrier for possible leaks.

5.11 VOC BACT – Storage Vessels

The Project includes small storage tanks for fuel (diesel fuel and aviation fuel), as well as a crude oil surge vessel.

5.11.1 Identification of Potential Control Technologies (Step 1)

The RBLC was used to obtain potential control technologies for VOC from storage tanks. The RBLC search covered petroleum storage (Process 42.005). The results of the RBLC search are included in Appendix D. A review of NSPS and state standards was also performed (see Section 4 of this application). The following control technology options were evaluated as potentially applicable for controlling VOC emissions from storage tanks:

- Combustion device (e.g., thermal oxidizer);
- Vapor recovery unit;
- Floating roof tanks; or
- Submerged fill.

5.11.2 Elimination of Technically Infeasible Control Options (Step 2)

Add-on control technologies (thermal oxidizer and vapor recovery unit) and floating roofs are eliminated in Step 2 for the diesel and aviation fuel tanks based on low vapor pressure, small size of the tanks, and the extremely small amount of VOC emissions (total potential emissions ~0.01 tpy).

The surge vessel is present to accommodate a surge in pipeline pressure, and the rapid filling of the tank cannot be incumbered for proper operation. Accordingly, add-on control devices which can cause back-pressure are not feasible to apply to the surge vessel. Because the purpose of surge vessels is to provide relief and not to provide liquid storage, a floating roof tank will not provide additional benefits from frequent working losses where air space is minimized by the floating roof. For the surge vessel on the offshore platform, the corrosive marine atmosphere, space and weight constraints, floating roof tanks can impede the operating purpose of the surge vessel with required maintenance. A fixed roof tank is necessary to accommodate the short-term relief in a surge event reliably. Accordingly, a floating roof tank emission control is not feasible for the offshore Project.

5.11.3 Rank of Remaining Control Technologies (Step 3)

The only technology not eliminated in Step 2 for the proposed storage vessels is the use of submerged fill. Submerged fill has an efficiency of 60% emissions control.

5.11.4 Evaluation of Most Stringent Control Technologies (Step 4)

As submerged fill is the only control option listed, a cost analysis is not required.

5.11.5 Selection of BACT (Step 5)

BMOP proposes the use of storage vessels designed with submerged fill loading as VOC BACT. Compliance will be based on the installation of tanks equipped with submerged fill pipes.

5.12 CO BACT – Large Non-Emergency Natural Gas-Fired Generators

5.12.1 Background on Pollutant Formation

CO emissions are primarily the result of incomplete combustion from carbon-containing fuels such as natural gas. If there is insufficient residence time at high temperatures, then the process is unable to complete the final step in hydrocarbon oxidation resulting in CO emissions. The oxidation of CO to CO_2 is a slow reaction compared to most hydrocarbon oxidation reactions.

5.12.2 Identification of Potential Control Technologies (Step 1)

The proposed project involves two (2) 1,736 kW (~2,328 hp) large non-emergency natural gas-fired 4-stroke lean-burn generator engines. The RICEs will be subject to NSPS Subpart JJJJ and NESHAP Subpart ZZZZ requirements as identified in Section 4 above. Per NSPS Subpart JJJJ, the regulations require purchasing a RICE certified to the applicable Tier standards or conducting performance testing to

demonstrate compliance with emission limits, whereas NESHAP ZZZZ requires the engines to reduce CO emissions or alternatively formaldehyde emissions. These standards and accompanying requirements are taken as the baseline for this BACT analysis.

The following CO control technologies have been identified:

- Good Combustion Practices; and
- Oxidation Catalyst

5.12.2.1 Good Combustion Practices

A detailed description of this control technology is provided in Section 5.6.2.

5.12.2.2 Oxidation Catalyst

A detailed description of this control technology is provided in Section 5.6.2.

5.12.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

5.12.3.1 Good Combustion Practices

GCP allow equipment to operate as efficiently as possible to maintain optimal emission release conditions from the unit. This is considered technically feasible for the control of CO emissions from the engines.

5.12.3.2 Oxidation Catalyst

A review of EPA's RBLC database shows that oxidation catalysts have been employed as BACT for the control of CO emissions for engines. BACT emission limits for units controlled by oxidation catalyst range from 0.0965 g/hp-hr to ~0.3 g/hp-hr, according to the RBLC search results, included in Appendix D to this application.

5.12.4 Rank of Remaining Control Technologies (Step 3)

The more effective control option from steps 1 and 2 is oxidation catalyst, which can achieve between 70 and 90% control for total CO, followed by GCP.

5.12.5 Evaluation of Most Stringent Control Technologies (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This step has been performed for each remaining control technology based on economic, energy, and environmental considerations, and is described in this section. In this step, once an option is selected, no further (i.e., lower ranking) options are assessed.

Good combustion practices are considered an inherent part of engine design and use. Thus, they are not associated with any additional costs or impacts. As well, BMOP has selected oxidation catalysts, as required to comply with NESHAP Subpart ZZZZ.

5.12.6 Selection of BACT (Step 5)

Similar to the VOC BACT, BMOP proposes a CO BACT emission limit based on vendor specifications for the natural gas engines fitted with oxidation catalysts of 0.23 g/hp-hr. BMOP will demonstrate compliance with the CO BACT limit consistent with the testing requirements of 40 CFR §60.4244 and Table 2 to Subpart JJJJ of Part 60.

At all times, BMOP will maintain the generators and oxidation catalysts in a manner consistent with safety and good air pollution control practices for minimizing emissions per 40 CFR §63.6605. BMOP will ensure proper maintenance of the catalyst such that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test. In addition, BMOP will maintain the temperature of the engine's exhaust so that the catalyst inlet temperature is greater than or equal to 450°F and less than or equal to 1,350°F, consistent with 40 CFR §63.6600(b) and Table 2b Subpart ZZZZ of Part 63. BMOP will install, operate, and maintain a temperature CPMS that meets the requirements of §63.6625(b) to continuously collect temperature data. In instances where the catalyst is changed, BMOP will reestablish the values of the operating parameters measured during the initial performance test and conduct a performance test to demonstrate that the engines are meeting the required emission limitations.

Because the oxidation catalyst is effective only at hot exhaust temperatures (>700°F), the use of Good Combustion Practices (GCP) and clean fuels will be the BACT work practice standards during startup to control CO emissions.

5.13 CO BACT – Large Emergency Diesel Firewater Pumps

5.13.1 Background on Pollutant Formation

CO is formed as an intermediate combustion product that appears in the exhaust when the reaction of CO to CO_2 cannot proceed to completion. This situation occurs if there is a lack of available oxygen near the hydrocarbon (fuel) molecule during combustion, if the gas temperature is too low, or if the residence time in the cylinder is too short. The oxidation rate of CO is limited by reaction kinetics and, as a consequence, can be accelerated only to a certain extent by improvements in air and fuel mixing during the combustion process.

5.13.2 Identification of Potential Control Technologies (Step 1)

The proposed project involves two (2) 485 kW (~650 hp) emergency diesel firewater pumps. The RICEs will be subject to NSPS Subpart IIII and NESHAP Subpart ZZZZ[87]. These regulations require purchasing RICEs certified to applicable Tier standards, combusting only ultra-low sulfur diesel, and various monitoring, recordkeeping, and reporting requirements. The engines will be subject to the emission standards which are established for nonroad engines in 40 CFR §89 and Table 4 of NSPS Subpart IIII, respectively. These standards and accompanying requirements are taken as the floor for this BACT analysis.

The following CO control technologies have been identified:

- Good Combustion Practices - GCP;
- Post-Combustion Control - Oxidation catalyst, or, more specifically, diesel oxidation catalyst (DOC); and

[87] Per 40 CFR §63.6600(c), the emergency diesel generator does not need to comply with emissions limitations or operating limits in NESHAP Subpart ZZZZ.

5.13.2.1 Good Combustion Practices

A detailed description of this control technology is provided in Section 5.7.2.

5.13.2.2 Oxidation Catalyst

A detailed description of this control technology is provided in Section 5.7.2.

5.13.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

The use of DOC reduces the effective power output of RICE and results in a solid waste stream. GCP is part of normal practice for emergency-use engines so no cost is associated with that option. Both control options are technically feasible.

5.13.4 Rank of Remaining Control Technologies (Step 3)

The more effective control option from steps 1 and 2 is oxidation catalyst, which can achieve between 10 and 60% control for CO emissions, followed by GCP.

5.13.5 Evaluation of Most Stringent Control Technologies (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This step has been performed for each remaining control technology based on economic, energy, and environmental considerations, and is described in this section. In this step, once an option is selected, no further (i.e., lower ranking) options are assessed.

5.13.5.1 Good Combustion Practices

Good combustion practices are an inherent part of engine use, so no additional costs or impacts are associated with their use.

5.13.5.2 Oxidation Catalyst

The use of DOC reduces the effective power output of RICE and results in a solid waste stream. GCP is part of normal practice for emergency-use engines, so no cost is associated with that option.

In its 2010 MACT/GACT evaluation for engines, EPA concluded for emergency engines: "Because these engines are typically used only a few number of hours per year [(27 hours per year per NFPA codes)], the costs of emission control are not warranted when compared to the emission reductions that would be achieved."[88]

5.13.6 Selection of BACT (Step 5)

The remaining control option, GCP, is selected as BACT for the two (2) 485 kW (~650 hp) large emergency diesel engines. As stated above, GCP for emergency engines is normal practice, i.e., operating the engines

[88] Ibid.

only for maintenance purposes, readiness testing, and during emergencies. The Project will ensure that the engines are operated only when needed for intermittent purposes. GCP will allow the engines to meet the CO emission limit in NSPS Subpart IIII of 3.5 g/kW-hr (2.6 g/bhp-hr). BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet these emission limits, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of the engines in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.14 CO BACT – Small Emergency Diesel Generators

5.14.1 Background on Pollutant Formation

Similar to large emergency diesel generators, CO is formed as an intermediate combustion product that appears in the exhaust when the reaction of CO to CO_2 cannot proceed to completion. This situation occurs if there is a lack of available oxygen near the hydrocarbon (fuel) molecule during combustion, if the gas temperature is too low, or if the residence time in the cylinder is too short. The oxidation rate of CO is limited by reaction kinetics and, as a consequence, can be accelerated only to a certain extent by improvements in air and fuel mixing during the combustion process.

5.14.2 Identification of Potential Control Technologies (Step 1)

The proposed project involves one (1) ~336 kW (450 hp) emergency diesel generator. The RICEs will be subject to NSPS Subpart IIII and NESHAP Subpart ZZZZ. These regulations require purchasing RICEs certified to applicable Tier standards, combusting only ultra-low sulfur diesel, and various monitoring, recordkeeping, and reporting requirements. The engines will be subject to the emission standards which are established for nonroad engines in 40 CFR §89 and Table 4 of NSPS Subpart IIII, respectively. These standards and accompanying requirements are taken as the floor for this BACT analysis.

The following CO control technologies have been identified:

- Combustion Control - GCP;
- Post-Combustion Control - Oxidation catalyst, or, more specifically, diesel oxidation catalyst (DOC); and

5.14.2.1 Good Combustion Practices

A detailed description of this control technology is provided in Section 5.7.2.

5.14.2.2 Oxidation Catalyst

A detailed description of this control technology is provided in Section 5.7.2.

5.14.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

The use of DOC reduces the effective power output of RICE and results in a solid waste stream. GCP is part of normal practice for emergency-use engines so no cost is associated with that option. Both control options are technically feasible.

5.14.4 Rank of Remaining Control Technologies (Step 3)

The more effective control option from steps 1 and 2 is oxidation catalyst, which can achieve between 10 and 60% control for CO emissions, followed by GCP.

5.14.5 Evaluation of Most Stringent Control Technologies (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This step has been performed for each remaining control technology based on economic, energy, and environmental considerations, and is described in this section. In this step, once an option is selected, no further (i.e., lower ranking) options are assessed.

5.14.5.1 Good Combustion Practices

Good combustion practices are an inherent part of engine use, so no additional costs or impacts are associated with their use.

5.14.5.2 Oxidation Catalyst

The use of DOC reduces the effective power output of RICE and results in a solid waste stream. GCP is part of normal practice for emergency-use engines so no cost is associated with that option.

In its 2010 MACT/GACT evaluation for engines, EPA concluded for emergency engines: "Because these engines are typically used only a few number of hours per year [(27 hours per year per NFPA codes)], the costs of emission control are not warranted when compared to the emission reductions that would be achieved."[89] Based on EPA's assessment and the fact that the RBLC contains no records of DOC installation on emergency-use or nonroad engines, DOC is eliminated from consideration as BACT.

5.14.6 Selection of BACT (Step 5)

The remaining control option, GCP, is selected as BACT for the one (1) 336 kW (~450 hp) small emergency diesel engine. As stated above, GCP for emergency engines is normal practice, i.e., operating the engines only for maintenance purposes, readiness testing, and during emergencies. The Project will ensure that the engines are operated only when needed for intermittent purposes. GCP will allow the engines to meet the CO emission limit in NSPS Subpart IIII of 3.5 g/kW-hr (2.6 g/bhp-hr). BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet these emission limits, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of the engines in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.15 CO BACT – Small Non-Emergency Diesel Crane Engines

5.15.1 Background on Pollutant Formation

CO is formed as an intermediate combustion product that appears in the exhaust when the reaction of CO to CO_2 cannot proceed to completion. This situation occurs if there is a lack of available oxygen near the hydrocarbon (fuel) molecule during combustion, if the gas temperature is too low, or if the residence time in the cylinder is too short. The oxidation rate of CO is limited by reaction kinetics and, as a consequence, can

[89] Ibid.

be accelerated only to a certain extent by improvements in air and fuel mixing during the combustion process.

5.15.2 Identification of Potential Control Technologies (Step 1)

The proposed project involves two (2) 354 kW (~475 hp) small non-emergency diesel crane engines. The RICE will be subject to NSPS Subpart IIII and NESHAP Subpart ZZZZ.[90] These regulations require purchasing RICE certified to applicable Tier standards, combusting only ultra-low sulfur diesel, and various monitoring, recordkeeping, and reporting requirements. The engines will be subject to the emission standards in 40 CFR §1039.101 for new and in-use nonroad CI engines. These standards and accompanying requirements are taken as the floor for this BACT analysis.

The following CO control technologies have been identified:

- Good Combustion Practices
- Oxidation Catalyst

5.15.2.1 Good Combustion Practices

A detailed description of this control technology is provided in Section 5.7.2.

5.15.2.2 Oxidation Catalyst

A detailed description of this control technology is provided in Section 5.7.2.

5.15.3 Elimination of Technically Infeasible Control Options (Step 2)

After the identification of potential control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits.

The use of DOC reduces the effective power output of RICE and results in a solid waste stream. In addition, the cranes will not require continuous operation. The crane engines will cycle through loads intermittently when in use. The non-continuous operation and intermittent cycling of the engines will lead to varying exhaust temperatures. Because oxidation catalysts require consistently high exhaust temperatures in excess of 700°F, the operating duty of the crane engines will lessen the effectiveness of catalysts, in a similar way as emergency engines.

GCP is part of normal practice for engines so no cost is associated with that option. Both control options are technically feasible.

5.15.4 Rank of Remaining Control Technologies (Step 3)

The more effective control option from steps 1 and 2 is oxidation catalyst, which can achieve between 10 and 60% control for CO emissions, followed by GCP.

[90] For new RICE with a site rating of less than or equal to 500 hp located at a major HAP source, the only requirement under NESHAP Subpart ZZZZ is to comply with NSPS Subpart IIII per 40 CFR §63.6590(c)(7).

5.15.5 Evaluation of Most Stringent Control Technologies (Step 4)

The fourth of the five steps in the top-down BACT assessment procedure is to evaluate the most effective control and document the results. This step has been performed for each remaining control technology based on economic, energy, and environmental considerations, and is described in this section. In this step, once an option is selected, no further (i.e., lower ranking) options are assessed.

5.15.5.1 Good Combustion Practices

Good combustion practices are an inherent part of engine use, so no additional costs or impacts are associated with their use.

5.15.5.2 Oxidation Catalyst

The use of oxidation catalyst reduces the effective power output of RICE and results in a solid waste stream. As well, because of the intermittent operation of the cranes and cycling of the engines while in use, the effectiveness of the oxidation catalysts will be limited. In addition to the reduced emissions mitigation, the costs of oxidation catalysts will be economically unreasonable with diminished effectiveness and limited operation.

5.15.6 Selection of BACT (Step 5)

The remaining control option, GCP, is selected as BACT for the two (2) 354 kW (~475 hp) diesel-fired crane engines. The Project will ensure that the engines are operated only when needed for intermittent purposes, at less than 4,380 hours per year, per engine. GCP will allow the engines to meet the CO emission limit in NSPS Subpart IIII of 3.5 g/kW-hr. BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet these emission limits, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of the engines to confirm compliance with the operating restriction.

5.16 NO_x BACT – Large Non-Emergency Natural Gas-Fired Generators

5.16.1 Background on Pollutant Formation

NO_x formation from fuel combustion primarily occurs through two different mechanisms. Thermal NO_x is formed from the thermal dissociation and subsequent reaction of N_2 and O_2 molecules in combustion air. Thermal NO_x formation is maximized in high temperatures and at slightly fuel-lean mixtures, due to excess oxygen available for reaction. Temperature reduction and stoichiometry control can help to suppress thermal NO_x formation.

Fuel NO_x is formed from the oxidation of fuel-bound nitrogen compounds into nitrogen oxides. The formation of fuel NO_x is dependent upon the type and nitrogen content of the fuel, air supply, and combustion temperature. The oxidation of elemental nitrogen into nitrogen oxides occurs very rapidly. Thus, fuel NO_x reduction is primarily achieved by reducing the amount of excess oxygen available to react with fuel-bound nitrogen.

5.16.2 Identification of Potential Control Technologies (Step 1)

The following NO_x control technologies have been identified:

- Good combustion practices

- Lean burn combustion
- Selective catalytic reduction (SCR)
- Selective non-catalytic reduction (SNCR)
- Nonselective catalytic reduction (NSCR)

5.16.2.1 Good Combustion Practices

Good combustion practices involve operating the engines as efficiently as possible to reduce potential emissions. When operated at the appropriate oxygen range and temperature which promotes complete fuel combustion, NO_x emissions will be reduced.

5.16.2.2 Lean Burn Combustion

In lean combustion systems, excess air is introduced into the combustion zone to produce a significantly leaner fuel/air mixture than is required for complete combustion. This excess air reduces the overall flame temperature because a portion of the energy released from the fuel must be used to heat the excess air to the reaction temperature. Pre-mixing the fuel and air prior to introduction into the combustion zone provides a uniform fuel/air mixture and prevents localized high temperature regions within the combustion cylinder. Since NO_x formation rates are an exponential function of temperature, a considerable reduction in NO_x can be achieved by lean combustion.

5.16.2.3 SCR

SCR systems involve the introduction of urea or ammonia into the exhaust gas stream upstream of a catalyst. Nitrogen oxides and O_2 in the exhaust gas react with the urea or ammonia to form N_2 and H_2O. SCR systems can achieve a NO_x removal efficiency of 50-90%. However, at temperatures above 750°F, the NO_x removal efficiency begins to decrease.[91]

5.16.2.4 SNCR

SNCR systems involve the introduction of urea or ammonia into the exhaust gas stream. Nitrogen oxides are reduced by this urea or ammonia to N_2 and H_2O. SNCR systems typically achieve a NO_x removal efficiency of 25-65%. Notably, SNCR best operates at high temperature ranges, such as 1600-2000°F for ammonia and 1650-2100°F for urea.[92]

5.16.2.5 NSCR

NSCR systems use a catalyst reaction to perform the reduction of NO_x using residual hydrocarbons and CO in an engine's exhaust. When the exhaust gas passes over the noble metal catalyst, the excess hydrocarbons and CO are oxidized to H_2O and CO_2, while the NO_x in the exhaust is reduced to N_2. NSCR systems can achieve NO_x removal efficiencies of 90% when operated at 800-1200°F.[93] As the excess hydrocarbons and CO will more readily react with O_2 than with NO_x, the O_2 content of the exhaust stream must be kept below approximately 1% to ensure NO_x reduction. The implementation of NSCR systems is

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[91] U.S. EPA, *Air Pollution Control Cost Manual,* Section 4, Chapter 2, 6th edition. EPA 452/B-02-001. Research Triangle Park, NC. Updated 6/12/2019.

[92] U.S. EPA, *Air Pollution Cost Manual,* Section 4, Chapter 1, 6th edition. EPA 452/B-02-001. Research Triangle Park, NC. Updated 4/29/2019.

[93] U.S. EPA, *Compliance Assurance Monitoring Technical Guidance Document*, Appendix B.16, "Nonselective Catalytic Reduction", Revision 1, Review Draft, January 2005.

limited to rich-burn engines, as lean-burn engines have lower exhaust temperatures and higher O_2 content than is allowed for NO_x reduction.

5.16.3 Elimination of Technically Infeasible Control Options (Step 2)

5.16.3.1 Good Combustion Practices

Good combustion practices allow equipment to operate as efficiently as possible to maintain optimal emission release conditions from the unit. This is considered technically feasible for the control of NO_x emissions from the generators.

5.16.3.2 Lean Burn Combustion

The large natural gas-fired generators proposed for installation at the WC 509 Platform Complex are Caterpillar 3516C, which utilize lean-burn technology. Thus, lean burn combustion is considered a technically feasible technology for the large non-emergency natural gas-firing generators at the WC 509 Platform Complex.

5.16.3.3 SCR

A review of EPA's RBLC database shows that SCR systems have been employed as BACT for the control of NO_x emissions from natural gas-firing generators with an engine rating greater than 500 hp. Notably, the generators which use this control technology are all located at on-shore facilities. Additionally, the NO_x removal efficiency of SCR systems begins to decrease above 750°F, a range in which the exhaust temperature of the large non-emergency natural gas-firing generators at the WC 509 Platform Complex (854°F) falls.[94] Thus, while not previously demonstrated at an offshore facility, SCR systems are considered a technically feasible technology.

5.16.3.4 SNCR

SNCR is suitable for sources with stable temperatures of 1550-1950°F.[95] As these temperatures are much higher than the exhaust temperatures of the large non-emergency natural gas-firing generators at the WC 509 Platform Complex, SNCR is considered to be technically infeasible.

5.16.3.5 NSCR

The large non-emergency natural-gas fired generators at the WC 509 Platform Complex are Caterpillar G3516C engines, which utilize lean-burn technology. NSCR systems cannot be implemented on lean-burn engines as the O_2 content in the exhaust gas stream is too high to achieve effective NO_x reduction. Thus, NSCR is considered to be technically infeasible.

5.16.4 Rank of Remaining Control Technologies (Step 3)

The most effective control option from steps 1 and 2 is the SCR system, which can achieve 50-90% reduction of NO_x emissions, followed by lean burn combustion and good combustion practices.

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[94] Per manufacturer specification sheets for a Caterpillar 3516C engine.

[95] U.S. EPA, *EPA Control Cost Manual Section 4 Chapter 1*, 6th edition. EPA 452/B-02-001. Research Triangle Park, NC. Updated 4/29/2019.

5.16.5 Evaluation of Most Stringent Control Technologies (Step 4)

5.16.5.1 SCR

Economic Impacts

The cost of implementing SCR was estimated based on calculations from the *EPA Air Pollution Control Cost Manual* with some sections updated to the Seventh Edition, and a cost estimate for capital needed to install a SCR system on the two large non-emergency natural gas-fired generators.[96] Detailed cost calculations are shown in Appendix D. The cost estimation assumed that the SCR could achieve a 50% reduction in NO_x emissions in the offshore setting (limited space for catalyst and control skids) and the elevated temperature of the engines. For each engine, installing the SCR system was estimated to cost more than $27,015 per ton of NO_x removed. The estimate incorporates some considerations for the additional cost of delivering equipment and replacement materials to an offshore marine platform, but it does not account for the full impact which will also include increased cost of commissioning, operating and maintenance labor, and other offshore operations. Further, the WC 509 Platform Complex is using every available area for the marine loading vapor capture and control system. Natural gas engine SCR would require reengineering the platform to accommodate additional equipment necessary for operation of the control – if it is even possible without adding a new platform. Thus, the cost of installing and operating the SCR system at the WC 509 Platform Complex is certain to be significantly higher. Additionally, the current Project specifications authorize that only one natural gas-fired generator may run at any one time, requiring the installation of an SCR system on both engines to provide for NO_x control. Thus, the implementation of SCR on the large non-emergency natural gas-fired generators at the WC 509 Platform Complex is considered to be economically unreasonable.

Environmental Impacts

Excess reagent passing through the SCR forms ammonia slip, which may cause a variety of health effects and can contribute to the formation of ammonium sulfates. Additionally, SO_3 may be formed from natural gas or fuel oil combustion after passing through the SCR; increased SO_3 may contribute to sulfuric acid formation, and subsequently condensable particulate matter. Delivery of the urea will require additional emissions from marine supply vessels, and catalyst replacement will create a solid waste and additional marine vessel emissions, otherwise avoided.

Energy Impacts

The flue gas pressure decreases as it flows across the catalyst, with the drop in pressure increasing with particulate matter deposits on the catalyst. The pressure drop may result in increased energy consumption, which in turn decreases the overall efficiency of the engine, as well as the need for additional maintenance. Additionally, NO_x removal via SCR is dependent on the reagent's dispersion throughout the flue gas. Achieving a satisfactory degree of mixing may require increased energy input through the operation of additional static mixers and injection nozzles which introduce the reagent into the flue gas stream.

5.16.5.2 Lean Burn Combustion

Lean burn combustion is an inherent part of engine design, so no additional costs or impacts are associated with its use.

[96] E*PA Air Pollution Control Cost Manual,* Chapter 2, Selective Catalytic Reduction, revised June 2019.

5.16.5.3 Good Combustion Practices

Good combustion practices are an inherent part of engine use, so no additional costs or impacts are associated with their use.

5.16.6 Selection of BACT (Step 5)

BMOP proposes the use of lean burn combustion and good combustion practices as BACT, which will allow the generators to meet an emission limit of 0.5 g/hp-hr.[97] The only additional technically feasible method of decreasing NO_x emissions is through implementation of SCR on each generator, which has been shown to be economically unreasonable in Step 4 of this analysis. BMOP will demonstrate compliance with the NO_x BACT limit consistent with the testing requirements of 40 CFR §60.4244 and Table 2 to Subpart JJJJ of Part 60.

5.17 NO_x BACT – Large Emergency Diesel Firewater Pumps

5.17.1 Background on Pollutant Formation

NO_x formation from fuel combustion is discussed in Section 5.16.1.

5.17.2 Identification of Potential Control Technologies (Step 1)

The following NO_x control technologies have been identified:

- Good combustion practices
- Injection timing retard (ITR)
- Exhaust gas recirculation (EGR)
- SCR
- SNCR
- NSCR

5.17.2.1 Good Combustion Practices

A detailed description of this control technology is provided in Section 5.16.2.

5.17.2.2 ITR

Fuel combustion is initiated in a compression ignition (CI) engine through injection of fuel into its cylinder. Delaying the diesel fuel injection causes combustion to start later in the power stroke, when the piston is moving downward and the combustion chamber volume is increasing. Through increasing the volume, the combustion temperature and pressure is lowered, reducing NO_x formation. ITR is capable of reducing NO_x from all diesel engines, though the NO_x reduction efficiency varies with the engine model.

5.17.2.3 EGR

In EGR, a portion of an engine's exhaust gas is cooled and recirculated back to the stream fed into the engine cylinders for combustion. As diesel engines operate with excess air, as much as 50% recirculated exhaust gas can be mixed with the combustion air. The exhaust gas/combustion air mixture lowers the temperature and O_2 content in the combustion cylinder, reducing the formation of thermal NO_x.

[97] Lower than the standarsd of 40 CFR 60.4233(e) and Table 1 of 40 CFR 60 Subpart JJJJ.

5.17.2.4 SCR, SNCR, and NSCR Systems

Detailed descriptions of these add-on control technologies are provided in Section 5.16.2.

5.17.3 Elimination of Technically Infeasible Control Options (Step 2)

5.17.3.1 Good Combustion Practices

Good combustion practices allow equipment to operate as efficiently as possible to maintain optimal emission release conditions from the engine. This is considered technically feasible for the control of NO_x emissions from the firewater pumps.

5.17.3.2 ITR

Engine manufacturers utilize ITR and variable timing as potential options to meet new engine standards, such as those at NSPS Subpart IIII.

5.17.3.3 EGR

Engine manufacturers utilize EGR and variable timing as potential options to meet new engine standards, such as those at NSPS Subpart IIII.

5.17.3.4 SCR, SNCR, and NSCR

Per the 2010 EPA MACT/GACT evaluation for emergency engines, the installation of SCR, SNCR, and NSCR for control of NO_x emissions from the large emergency diesel firewater pumps would not be cost-effective due to their intermittent use (defined as 27 hours per year per NFPA codes).[98] Additionally, a review of EPA's RBLC database shows that SCR, SNCR, and NSCR have not been determined as NO_x BACT for any large emergency diesel firewater pumps. Thus, these technologies are considered to be technically infeasible.

5.17.4 Rank of Remaining Control Technologies (Step 3)

The remaining control technology is good combustion practices, and engine manufacturers utilization of ITR/EGR.

5.17.5 Evaluation of Most Stringent Control Technologies (Step 4)

Good combustion practices, ITR and EGR are considered an inherent part of engine design and use. Thus, they are not associated with any additional costs or impacts.

5.17.6 Selection of BACT (Step 5)

BMOP will operate the pumps only when needed for emergency purposes and intermittent maintenance and testing. BMOP proposes the use of good combustion practices and selection of engines that are certified to meet the NO_x emission limit in NSPS Subpart IIII of 4.0 g/kW-hr (3.0 g/bhp-hr) as BACT.[99] BMOP will demonstrate compliance with the BACT standard by installing an engine that is certified to meet the

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[98] EPA, *Alternative Control Techniques Document: Stationary Diesel Engines*, March 5, 2010, p. 41. (https://www.epa.gov/sites/production/files/2014-02/documents/3_2010_diesel_eng_alternativecontrol.pdf)

[99] 40 CFR 60.4205(b) and Table 4 of 40 CFR 60 Subpart IIII. Conservatively, the emission limit for NMHC + NO_x is assumed as the NO_x BACT emission limit.

emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of the engine and keep records of the operation of the engine in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.18 NO_x BACT – Small Emergency Diesel Generator

5.18.1 Background on Pollutant Formation

NO_x formation from fuel combustion is discussed in Section 5.16.1.

5.18.2 Identification of Potential Control Technologies (Step 1)

The following NO_x control technologies have been identified:

- Good combustion practices
- ITR
- EGR
- SCR
- SNCR
- NSCR

Detailed descriptions of each control technology are provided in Section 5.16.2.

5.18.3 Elimination of Technically Infeasible Control Options (Step 2)

5.18.3.1 Good Combustion Practices

Good combustion practices allow equipment to operate as efficiently as possible to maintain optimal emission release conditions from the engine. This is considered technically feasible for the control of NO_x emissions from the generator.

5.18.3.2 ITR

Engine manufacturers utilize ITR and variable timing as potential options to meet new engine standards, such as those at NSPS Subpart IIII.

5.18.3.3 EGR

Engine manufacturers utilize EGR and variable timing as potential options to meet new engine standards, such as those at NSPS Subpart IIII.

5.18.3.4 SCR and SNCR

Per the 2010 EPA MACT/GACT evaluation for emergency engines, the installation of SCR and SNCR for control of NO_x emissions from the small emergency diesel generator would not be cost-effective due to its intermittent use (defined as 27 hours per year per NFPA codes).[100] Additionally, a review of EPA's RBLC database shows that SCR and SNCR have not been determined as NO_x BACT for any small (<500 hp) emergency diesel generators. Thus, these technologies are considered to be technically infeasible.

[100] EPA, *Alternative Control Techniques Document: Stationary Diesel Engines*, March 5, 2010, p. 41. (https://www.epa.gov/sites/production/files/2014-02/documents/3_2010_diesel_eng_alternativecontrol.pdf)

5.18.3.5 NSCR

The small emergency diesel generator proposed for installation is a Caterpillar G3512C engine which utilizes lean-burn technology. NSCR systems cannot be implemented on lean-burn engines as the O_2 content in the exhaust gas stream is too high to achieve effective NO_x reduction. Thus, NSCR is considered to be technically infeasible.

5.18.4 Rank of Remaining Control Technologies (Step 3)

The remaining control technology is good combustion practices, and engine manufacturer's utilization of ITR/EGR.

5.18.5 Evaluation of Most Stringent Control Technologies (Step 4)

Good combustion practices, ITR and EGR are considered an inherent part of engine design and use. Thus, they are not associated with any additional costs or impacts.

5.18.6 Selection of BACT (Step 5)

BMOP will operate the generator only when needed for emergency purposes and intermittent maintenance and testing. BMOP proposes the use of good combustion practices and selection of an engine that is certified to meet the NO_x emission limit in NSPS Subpart IIII of 4.0 g/kW-hr as BACT.[101] BMOP will demonstrate compliance with the BACT standard by installing an engine that is certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of the engine and keep records of the operation of the engine in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.19 NO_x BACT – Small Non-Emergency Diesel Crane Engines

5.19.1 Background on Pollutant Formation

NO_x formation from fuel combustion is discussed in Section 5.16.1.

5.19.2 Identification of Potential Control Technologies (Step 1)

The following NO_x control technologies have been identified:

- Good combustion practices
- ITR
- EGR
- SCR
- SNCR
- NSCR

Detailed descriptions of each control technology are provided in Section 5.16.2.

[101] 40 CFR 60.4202(a)(2) and Table 3 of Appendix I to 40 CFR 1039. Conservatively, the emission limit for NMHC + NO_x is assumed as the NO_x BACT emission limit.

5.19.3 Elimination of Technically Infeasible Control Options (Step 2)

5.19.3.1 Good Combustion Practices

Good combustion practices allow equipment to operate as efficiently as possible to maintain optimal emission release conditions from the engine. This is considered technically feasible for the control of NO_x emissions from the engines.

5.19.3.2 ITR

Engine manufacturers utilize ITR and variable timing as potential options to meet new engine standards, such as those at NSPS Subpart IIII.

5.19.3.3 EGR

Engine manufacturers utilize EGR and variable timing as potential options to meet new engine standards, such as those at NSPS Subpart IIII.

5.19.3.4 SCR, SNCR, and NSCR

The installation of SCR, SNCR, and NSCR for control of NO_x emissions from the small non-emergency diesel crane engines would not be cost-effective given their intermittent use. Additionally, a review of EPA's RBLC database shows that SCR, SNCR, and NSCR have not been determined as NO_x BACT for any small, non-emergency-use diesel engines. Thus, these technologies are considered to be technically infeasible.

5.19.4 Rank of Remaining Control Technologies (Step 3)

The remaining control technology is good combustion practices, and engine manufacturer's utilization of ITR/EGR.

5.19.5 Evaluation of Most Stringent Control Technologies (Step 4)

Good combustion practices, ITR and EGR are considered an inherent part of engine design and use. Thus, they are not associated with any additional costs or impacts.

5.19.6 Selection of BACT (Step 5)

BMOP proposes the use of good combustion practices and selection of engines that are certified to meet the NO_x emission limit in NSPS Subpart IIII of 0.6 g/kW-hr as BACT.[102] BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of the engines to confirm compliance with the operating restriction.

5.20 $PM_{10}/PM_{2.5}$ BACT – Large Non-Emergency Natural Gas Fired Generators

5.20.1 Background on Pollutant Formation

$PM_{10}/PM_{2.5}$ emissions may be divided into "filterable" and "condensable" fractions. Filterable PM emissions consist of noncombustible trace constituents which are present in the fuel, such as ash and sulfur.

[102] 40 CFR 60.4204(b) and Table 1 of 40 CFR 1039.101. Per 40 CFR 1039.101(e), NO_x emissions are multiplied by the appropriate NTE multiplier.

Condensable PM emissions exist in gaseous form in the exhaust gas stream and condense in the cooler ambient air to form particulate matter. Condensable PM includes sulfuric and nitric acid formed from the oxidation of sulfur and NO_x, respectively.

With its potential oxidation to nitric acid, NO_x may contribute to secondary PM formation from fuel combustion. In this report, secondary PM BACT is addressed through controlling direct NO_x emissions as detailed in Section 5.11.

5.20.2 Identification of Potential Control Technologies (Step 1)

The following $PM_{10}/PM_{2.5}$ control technologies have been identified:

- Inherently clean fuels
- Good combustion practices
- Wet scrubbers
- Baghouses
- Electrostatic precipitators (ESP)
- Multicyclones

5.20.2.1 Inherently Clean Fuels

The use of inherently clean fuels involves combusting fuels with low sulfur content to limit the formation of filterable PM. Additionally, combustion of low-sulfur fuels minimizes the formation of SO_2, a precursor to condensable PM.

5.20.2.2 Good Combustion Practices

Good combustion practices involve operating the engines as efficiently as possible to reduce potential emissions. When operated at the appropriate oxygen range and temperature which promotes complete fuel combustion, PM emissions will be reduced.

5.20.2.3 Wet Scrubbers

In a wet scrubber, particulate matter dissolves into a liquid which is injected into the exhaust gas stream. Particulate-containing liquid droplets are then separated by gravity.

5.20.2.4 Baghouses

A baghouse consists of several fabric filters, typically configured in long, vertically suspended sock-like configurations. Particulate laden gas enters from one side, often from the outside of the bag, passing through the filter media and forming a particulate cake. Based on allowable pressure drop, the cake is removed by shaking or pulsing the fabric, which loosens the cake from the filter, allowing it to fall into a bin at the bottom of the baghouse.

5.20.2.5 ESP

An ESP removes particles from an air stream by electrically charging the particles and then passing them through a force field that causes them to migrate to an oppositely charged collector plate. After the particles are collected, the plates are knocked ("rapped"), and the accumulated particles fall into a collection hopper at the bottom of the ESP.

5.20.2.6 Multicyclones

Multicyclones consist of several small cyclones operating in parallel. The cyclone creates a double vortex inside its shell, conveying centrifugal force on the inlet exhaust stream. The exhaust stream is then forced to move circularly through the cyclone, and the particulate matter in the stream is pushed to the cyclone walls.

5.20.3 Elimination of Technically Infeasible Control Options (Step 2)

A review of large (engine rating > 500 hp) natural gas-fired engines used for non-emergency purposes from the RBLC database identified none which utilized wet scrubbers, baghouses, electrostatic precipitators, or multicyclones for control of $PM_{10}/PM_{2.5}$ emissions. Thus, these control technologies are considered technically infeasible.

5.20.4 Rank of Remaining Control Technologies (Step 3)

The remaining technically feasible controls are the use of inherently clean fuels, such as natural gas, and good combustion practices.

5.20.5 Evaluation of Most Stringent Control Technologies (Step 4)

Per the RBLC filtered search results, the combustion of natural gas (an inherently clean fuel) and good combustion practices have been designated as BACT for several large non-emergency natural gas-fired engines at onshore facilities, suggesting that they are technically feasible for a similar source on the WC 509 Platform Complex. As the combustion of inherently clean fuels and good combustion practices are an inherent part of engine use and are not add-on controls, no additional costs or impacts are associated with their use.

5.20.6 Selection of BACT (Step 5)

BMOP proposes the use of natural gas and good combustion practices as $PM_{10}/PM_{2.5}$ BACT. BMOP will demonstrate compliance with the work practice standard by keeping records of maintenance performed on the engines.

5.21 $PM_{10}/PM_{2.5}$ BACT – Large Emergency Diesel Firewater Pumps

5.21.1 Background on Pollutant Formation

$PM_{10}/PM_{2.5}$ emissions from fuel combustion are discussed in Section 5.20.1.

5.21.2 Identification of Potential Control Technologies (Step 1)

The following $PM_{10}/PM_{2.5}$ control technologies have been identified:

- Good combustion practices
- Inherently clean fuels
- Wet scrubbers
- Baghouses
- Electrostatic precipitators
- Multicyclones
- DOC

- Diesel particulate filter (DPF)

The use of good combustion practices, inherently clean fuels, wet scrubbers, baghouses, ESP, and multicyclones as a $PM_{10}/PM_{2.5}$ control technology is discussed in Section 5.20.2.

5.21.2.1 DOC

A DOC contains a honeycomb-like structure or substrate coated with an active catalyst layer (typically a precious metal) which oxidizes gaseous hydrocarbons and liquid unburned fuel in the engine's exhaust gas stream into CO_2 and H_2O. DOCs verified by the U.S. EPA and California Air Resources Board (CARB) are typically effective at reducing PM emissions by 20 to 40%.[103]

5.21.2.2 DPF

DPFs typically consist of a porous ceramic or cordierite substrate or metallic filter which physically traps PM and removes it from the exhaust stream. The collected PM is reduced to ash during regeneration, when the DPF is heated until it reaches the temperature required for combustion of the PM. DPFs verified by the U.S. EPA and CARB are typically able to reduce PM emissions by 85 to 90%.[104]

5.21.3 Elimination of Technically Infeasible Control Options (Step 2)

A review of large emergency diesel firewater pumps from the RBLC database identified none which were required to utilize wet scrubbers, baghouses, ESP, multicyclones, DOC, or DPF for control of $PM_{10}/PM_{2.5}$ emissions. Thus, these control technologies are considered technically infeasible.

5.21.4 Rank of Remaining Control Technologies (Step 3)

The remaining technically feasible controls are the use of inherently clean fuels, such as ultra-low sulfur diesel, and good combustion practices.

5.21.5 Evaluation of Most Stringent Control Technologies (Step 4)

Per the RBLC filtered search results, the combustion of ultra-low sulfur diesel and good combustion practices have been designated as BACT for several large emergency diesel firewater pumps. As the combustion of inherently clean fuels and good combustion practices are an inherent part of engine use and are not add-on controls, no additional costs or impacts are associated with their use.

5.21.6 Selection of BACT (Step 5)

BMOP will operate the pumps only when needed for emergency purposes and intermittent maintenance and testing. Good combustion practices and combustion of ultra-low sulfur diesel will allow the engine to meet the PM emission limit in NSPS Subpart IIII of 0.2 g/kW-hr (0.15 g/bhp-hr).[105] BMOP will demonstrate compliance with the BACT standard by installing an engine that is certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of

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[103] U.S. EPA, *Technical Bulletin: Diesel Oxidation Catalyst General Information*, EOA-420-F-10-031, May 2010 (available at: https://www.epa.gov/sites/default/files/2016-03/documents/420f10031.pdf).

[104] U.S. EPA, *Technical Bulletion: Diesel Particulate Filter General Information*, EPA-420-F-10-029, May 2010 (available at: https://www.epa.gov/sites/default/files/2016-03/documents/420f10029.pdf).

[105] 40 CFR 60.4205(b) and Table 4 of 40 CFR 60 Subpart IIII.

the engine and keep records of the operation of the engine in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.22 $PM_{10}/PM_{2.5}$ BACT – Small Emergency Diesel Engines

5.22.1 Background on Pollutant Formation

$PM_{10}/PM_{2.5}$ emissions from fuel combustion are discussed in Section 5.20.1.

5.22.2 Identification of Potential Control Technologies (Step 1)

The following $PM_{10}/PM_{2.5}$ control technologies have been identified:

- Good combustion practices
- Inherently clean fuels
- Wet scrubbers
- Baghouses
- Electrostatic precipitators
- Multicyclones
- DOC

These control technologies are discussed in Section 5.20.2.

5.22.3 Elimination of Technically Infeasible Control Options (Step 2)

A review of small emergency diesel engines from the RBLC database identified none which were required to utilize wet scrubbers, baghouses, ESP, multicyclones, DOC, or DPF for control of $PM_{10}/PM_{2.5}$ emissions. Additionally, given the engine's intermittent use and infrequent operation, implementation of any of these add-on control technologies would not be cost effective. Thus, these control technologies are considered technically infeasible.

5.22.4 Rank of Remaining Control Technologies (Step 3)

The remaining technically feasible controls are the use of inherently clean fuels, such as ultra-low sulfur diesel, and good combustion practices.

5.22.5 Evaluation of Most Stringent Control Technologies (Step 4)

Per the RBLC filtered search results, the combustion of ultra-low sulfur diesel and good combustion practices have been designated as BACT for several small emergency diesel engines. As the combustion of inherently clean fuels and good combustion practices are an inherent part of engine use and are not add-on controls, no additional costs or impacts are associated with their use.

5.22.6 Selection of BACT (Step 5)

BMOP will operate the generator only when needed for emergency purposes and intermittent maintenance and testing. Good combustion practices and combustion of ultra-low sulfur diesel will allow the engine to meet the PM emission limit in NSPS Subpart IIII of 0.2 g/kW-hr (0.15 g/bhp-hr).[106] BMOP will demonstrate

[106] 40 CFR 60.4202(a)(2) and Table 3 of Appendix I to 40 CFR 1039. Conservatively, the emission limit for NMHC + NO_x is assumed as the NO_x BACT emission limit.

compliance with the BACT standard by installing an engine that is certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of the engine and keep records of the operation of the engine in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.23 $PM_{10}/PM_{2.5}$ BACT – Small Non-Emergency Diesel Crane Engines

5.23.1 Background on Pollutant Formation

$PM_{10}/PM_{2.5}$ emissions from fuel combustion are discussed in Section 5.20.1.

5.23.2 Identification of Potential Control Technologies (Step 1)

The following $PM_{10}/PM_{2.5}$ control technologies have been identified:

- Good combustion practices
- Inherently clean fuels
- Wet scrubbers
- Baghouses
- Electrostatic precipitators
- Multicyclones
- DOC

These control technologies are discussed in Section 5.20.2.

5.23.3 Elimination of Technically Infeasible Control Options (Step 2)

A review of small non-emergency diesel engines from the RBLC database identified none which were required to utilize wet scrubbers, baghouses, ESP, multicyclones, or DOC for control of $PM_{10}/PM_{2.5}$ emissions. Additionally, given the engines' intermittent use at an offshore platform, required implementation of any of these add-on control technologies beyond vendor default packages would not be cost effective. Thus, these control technologies are considered technically infeasible.

5.23.4 Rank of Remaining Control Technologies (Step 3)

The remaining technically feasible controls are the use of inherently clean fuels, such as ultra-low sulfur diesel, and good combustion practices.

5.23.5 Evaluation of Most Stringent Control Technologies (Step 4)

Per the RBLC filtered search results, the combustion of ultra-low sulfur diesel and good combustion practices have been designated as BACT for several small non-emergency diesel engines. As the combustion of inherently clean fuels and good combustion practices are an inherent part of engine use and are not add-on controls, no additional costs or impacts are associated with their use.

5.23.6 Selection of BACT (Step 5)

Good combustion practices and combustion of ultra-low sulfur diesel will allow the engines to meet the PM emission limit in NSPS Subpart IIII of 0.03 g/kW-hr.[107] BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of the engines to confirm compliance with the operating restriction.

5.24 GHG BACT – Large Non-Emergency Natural Gas Fired Generators

5.24.1 Background on Pollutant Formation

The principal greenhouse gases (GHGs) formed from human activity are CO_2, CH_4, and N_2O. CO_2 production from combustion occurs in theory by a reaction between carbon in any fuel and oxygen in the air.[108] CH_4 can be emitted when natural gas and fuel oil undergo incomplete combustion.[109] N_2O is produced from fossil fuel combustion, but its formation is limited during complete gas and oil combustion situations, as most oxides of nitrogen will tend to oxidize completely to NO_2, which is not a GHG.[110] Following the implementation of the Project at the WC 509 Platform Complex, potential CO_2 emissions represent more than 99% of the total GHG emissions on a CO_2e basis, while potential CH_4 and N_2O emissions represent less than 1% of the total GHG emissions on a CO_2e basis.

5.24.2 Identification of Potential Control Technologies (Step 1)

The following GHG control technologies have been identified:

- Low carbon fuels
- Good combustion practices
- Carbon capture and storage (CCS)
- CH_4 oxidation catalyst
- N_2O catalytic reduction

5.24.2.1 Low Carbon Fuels

As detailed in Section 5.24.1, the amount of GHG emissions generated from a combustion source depends upon the fuel used. Fuels with a lower carbon intensity will produce less GHG emissions per heating value. As shown in Tables C-1 and C-2 to Subpart C of Part 98, natural gas has lower default CO_2, CH_4, and N_2O emission factors than petroleum products.

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[107] 40 CFR 60.4204(b) and Table 1 of 40 CFR 1039.101. Per 40 CFR 1039.101(e), PM emissions are multiplied by the appropriate NTE multiplier.

[108] U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020*, Chapter 1, *Introduction*. April 2022, accessed at https://www.epa.gov/system/files/documents/2022-04/us-ghg-inventory-2022-chapter-1-introduction.pdf

[109] U.S. EPA, AP-42, Chapter 1, Section 4, *Natural Gas Combustion*, Chapter 1, Section 3, *Fuel Oil Combustion*. July 1998.

[110] U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020*, Chapter 1, *Introduction*. April 2022, accessed at https://www.epa.gov/system/files/documents/2022-04/us-ghg-inventory-2022-chapter-1-introduction.pdf

5.24.2.2 Good Combustion Practices

Good combustion practices involve operating the engines as efficiently as possible to reduce potential emissions. When operated at the appropriate oxygen range and temperature which promotes complete fuel combustion, GHG emissions will be reduced.

5.24.2.3 CCS

Carbon capture and storage (CCS) involves the separation and capture of CO_2 from flue gas prior to discharging into the atmosphere, the pressurization and transportation via pipeline of the captured CO_2, and utilization or long-term geologic storage. In the first step of most CCS systems, CO_2 is adsorbed onto a chemical solvent (often amine-based), which is then heated to release the CO_2 and undergo regeneration.[111] Many chemical solvents are degraded upon exposure to SO_2 or HCl and are best suited for use in exhaust gas streams with no or very low quantities of these compounds. Cooling of the flue gas prior to "scrubbing" with solvent allows for the removal of these acid gases and the effective adsorption of CO_2 onto the solvent. The captured CO_2 is then compressed from near atmospheric to much higher pressures, which allows for its flow through pipelines and into target storage formations as a supercritical fluid.

Maintaining CO_2 as a supercritical fluid in the storage formation is typically accomplished in reservoirs that are at depths greater than 800 meters below the Earth's surface, as the pressure at those depths make CO_2 less likely to migrate out of the geological formation.[112] Candidate CO_2 storage reservoirs are separated from the surface by impermeable formations, such as shale, to keep injected CO_2 trapped underground. Reservoirs which have been considered for geologic CO_2 storage include deep saline formations, depleted natural gas or oil reservoirs, and deep unmineable coal seams.

5.24.2.4 CH_4 Oxidation Catalyst

Oxidation catalysts have been proposed as a method for controlling CH_4 emissions from natural gas-fired engines, as CH_4 is the primary component of the fuel. As CH_4 is a highly stable compound, higher catalyst temperatures are required for its oxidation compared to those required for the removal of VOC and CO emissions. Palladium-based catalysts have been shown to have the most potential for sufficient methane oxidation at 380-450°C (typical operating temperatures for VOC and CO oxidation).[113] However, palladium-based catalysts rapidly lose their activity when small amounts of SO_2 are present in the exhaust gas stream.

5.24.2.5 N_2O Catalytic Reduction

The only commercial N_2O control technology is the use of catalysts in nitric/adipic acid plant applications to minimize N_2O emissions.[114] Through this technology, tail gas from the nitric acid production process is

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[111] U.S. EPA, *Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants: Emission Guidelines for Greenhouse Gas Emissions from Existing Stationary Sources: Electric Utility Generating Units*, EPA-HQ-OAR-2013-0602, August 2015.

[112] A.C. Jones and A.J. Lawson, Congressional Research Service Report R44902, *Carbon Capture and Sequestration (CCS) in the United States*, October 5, 2022.

[113] de Wit, J., et al., 2000. "Catalytic Emission Control with Respect to CH4 and CO for Highly Efficient Gas Fueled Decentralised Heat and Power Production", Proceedings of teh 5th European Conference on Industrial Furnaces and Boilers, Lisbon, Portugal, Vol II, 587-595, https://www.dgc.dk/sites/default/files/filer/publikationer/C0001_catalytic_emission_control.pdf

[114] N20 Emissions from Adipic Acid and Nitric Acid Production, written by Heike Mainhardt (ICF Incorporated) and reviewed by Dina Kruger (U.S. EPA). http://www.ipcc-nggip.iges.or.jp/public/gp/bgp/3_2_Adipic_Acid_Nitric_Acid_Production.pdf

routed to a reactor vessel with a N_2O catalyst followed by ammonia injection and a NO_X catalyst. N_2O is decomposed to form N_2 and O_2.

5.24.3 Elimination of Technically Infeasible Control Options (Step 2)

5.24.3.1 Low Carbon Fuels

The generators will fire natural gas, which has a lower carbon intensity than diesel or other fuels. Thus, low carbon fuels are considered technically feasible.

5.24.3.2 Good Combustion Practices

Good combustion practices allow equipment to operate as efficiently as possible to maintain optimal emission release conditions from the engine. This is considered technically feasible for the control of GHG emissions from the engines.

5.24.3.3 CCS

The first step of CCS is CO_2 capture and compression. Currently, three main approaches are available to capture CO_2 from large-scale industrial facilities or power plants: post-combustion capture, precombustion capture, and oxy-fuel combustion capture. Of these three approaches, only post-combustion capture has been shown to be a viable method to remove CO_2 from exhaust gas following combustion of fossil fuels or biomass prior to its discharging into the atmosphere. Though precombustion capture methods have been implemented at power plants, they do not use carbon capture and storage to remove CO_2 from flue gas streams after fuel combustion.[115] Oxy-fuel combustion capture systems have yet to be demonstrated at large-scale industrial facilities.

With current technology, the most effective method of CO_2 capture from fuel combustion exhaust is by chemical reaction with a monoethanolamine (MEA), one of a family of amine compounds.[116] Operation of a carbon capture system increases the amount of fuel needed to generate electricity relative to a similar plant without CO_2; this increase is often referred to as an "energy penalty". From an MIT study of carbon capture systems, thermal energy for amine solvent regeneration accounts for approximately 60% of this energy penalty, while the electricity required for CO_2 compression to a supercritical fluid account for approximately 30%. Plant water consumption also increases from the cooling of flue gases prior to post-combustion capture to allow for the removal of acid gases prior to solvent "scrubbing".

The location of the generators at a marine offshore platform provides limited space for MEA and cold water storage prior to its use in carbon capture. Additionally, BMOP would incur significant costs in the delivery of MEA to the platform, the operation of the energy-intensive post-combustion capture system, and the additional energy needed to cool flue gases and compress CO_2 to a supercritical fluid. Given these additional space and energy requirements, CCS is considered technically infeasible.

5.24.3.4 CH_4 Oxidation Catalyst

Oxidation catalysts capable of reducing CH_4 emissions operate at higher temperatures than commercially-available VOC and CO oxidation catalysts. Additionally, CH_4 oxidation catalysts are vulnerable to fouling from

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[115] A.C. Jones and A.J. Lawson, Congressional Research Service Report R44902, *Carbon Capture and Sequestration (CCS) in the United States*, October 5, 2022.

[116] P. Folger, Congressional Research Service Report R41325, *Carbon Capture: A Technology Assessment*, November 5, 2013.

exposure to SO_2 and water vapor in the exhaust gas stream. Thus, CH_4 oxidation catalysts are considered technically infeasible.

5.24.3.5 N_2O Catalytic Reduction

N_2O catalytic reduction requires the implementation of an ammonia injection system. The WC 509 Platform Complex has limited space for this system and the storage of ammonia prior to its use. Additionally, BMOP would incur additional costs for the delivery of ammonia and replacement catalysts to the offshore marine platform for use in N_2O catalytic reduction. Additionally, the implementation of this control technology would not be effective given the minimal production of N_2O from fuel combustion. Thus, N_2O catalytic reduction is considered technically infeasible.

5.24.4 Rank of Remaining Control Technologies (Step 3)

The remaining technically feasible controls are the use of low carbon fuels and good combustion practices.

5.24.5 Evaluation of Most Stringent Control Technologies (Step 4)

Per the RBLC filtered search results, the use of low carbon fuels and good combustion practices have been designated as BACT for several large non-emergency natural gas-fired engines at onshore facilities, suggesting that they are technically feasible for a similar source on the WC 509 Platform Complex. As the combustion of low carbon fuels and good combustion practices are an inherent part of engine use and are not add-on controls, no additional costs or impacts are associated with their use.

5.24.6 Selection of BACT (Step 5)

BMOP proposes the use of natural gas (a low carbon fuel) and good combustion practices as GHG BACT. BMOP will demonstrate compliance with the annual BACT limit of 12,871 tons CO_2e/yr, combined, by monitoring fuel consumption and utilizing the emission factors of 40 CFR Part 98, Subpart C, Tables C-1 and C-2 and the current global warming potential from Subpart A to 40 CFR Part 98 (1 for CO_2, 25 for CH_4, and 298 for N_2O). These calculations will be performed on a monthly basis to ensure that the 12-month rolling total tons per year emission limit is not exceeded.

5.25 GHG BACT – Large Emergency Diesel Firewater Pumps

5.25.1 Background on Pollutant Formation

GHG formation from fuel combustion is discussed in Section 5.24.1.

5.25.2 Identification of Potential Control Technologies (Step 1)

The following GHG control technologies have been identified:

- Low carbon fuels
- Good combustion practices
- Carbon capture and storage (CCS)
- CH_4 oxidation catalyst
- N_2O catalytic reduction

These combustion technologies are discussed in greater detail in Section 5.24.2.

5.25.3 Elimination of Technically Infeasible Control Options (Step 2)

5.25.3.1 Low Carbon Fuels

The generators are authorized to fire diesel, which has a higher carbon intensity than natural gas. However, the WC 509 Platform Complex does not have the capacity to store natural gas for use during emergency operations. Thus, the use of natural gas as a low carbon fuel is considered technically infeasible.

5.25.3.2 Good Combustion Practices

Good combustion practices allow equipment to operate as efficiently as possible to maintain optimal emission release conditions from the engine. This is considered technically feasible for the control of GHG emissions from the engines.

5.25.3.3 CCS

As discussed in Section 5.24.3.3, the additional storage and energy requirements associated with the implementation of a CCS system at the WC 509 Platform Complex makes this control technically infeasible.

5.25.3.4 CH_4 Oxidation Catalyst

As discussed in Section 5.24.3.4, the higher catalytic temperature requirements for CH_4 oxidation and vulnerability to fouling from SO_2 and water vapor exposure makes this control technically infeasible.

5.25.3.5 N_2O Catalytic Reduction

As discussed in Section 5.24.3.5, the additional costs and space requirements needed for the implementation of N_2O catalytic reduction at the WC 509 Platform Complex make this control technically infeasible.

5.25.4 Rank of Remaining Control Technologies (Step 3)

The remaining technically feasible control is the use of good combustion practices.

5.25.5 Evaluation of Most Stringent Control Technologies (Step 4)

Per the RBLC filtered search results, the use of good combustion practices has been designated as BACT for several large emergency diesel firewater pumps. As good combustion practices are part of engine use and are not add-on controls, no additional costs or impacts are associated with their use.

5.25.6 Selection of BACT (Step 5)

BMOP proposes the use of good combustion practices as GHG BACT. BMOP will demonstrate compliance with the work practice standard by keeping records of maintenance performed on the engines.

5.26 GHG BACT – Small Emergency Diesel Generators

5.26.1 Background on Pollutant Formation

GHG formation from fuel combustion is discussed in Section 5.24.1.

5.26.2 Identification of Potential Control Technologies (Step 1)

The following GHG control technologies have been identified:

- Low carbon fuels
- Good combustion practices
- Carbon capture and storage (CCS)
- CH_4 oxidation catalyst
- N_2O catalytic reduction

These combustion technologies are discussed in greater detail in Section 5.24.2.

5.26.3 Elimination of Technically Infeasible Control Options (Step 2)

5.26.3.1 Low Carbon Fuels

The generators are authorized to fire diesel, which has a higher carbon intensity than natural gas. However, the WC 509 Platform Complex does not have the capacity to store natural gas for use during emergency operations. Thus, the use of natural gas as a low carbon fuel is considered technically infeasible.

5.26.3.2 Good Combustion Practices

Good combustion practices allow equipment to operate as efficiently as possible to maintain optimal emission release conditions from the engine. This is considered technically feasible for the control of GHG emissions from the engines.

5.26.3.3 CCS

As discussed in Section 5.24.3.3, the additional storage and energy requirements associated with the implementation of a CCS system at the WC 509 Platform Complex makes this control technically infeasible.

5.26.3.4 CH_4 Oxidation Catalyst

As discussed in Section 5.24.3.4, the higher catalytic temperature requirements for CH_4 oxidation and vulnerability to fouling from SO_2 and water vapor exposure makes this control technically infeasible.

5.26.3.5 N_2O Catalytic Reduction

As discussed in Section 5.24.3.5, the additional costs and space requirements needed for the implementation of N_2O catalytic reduction at the WC 509 Platform complex make this control technically infeasible.

5.26.4 Rank of Remaining Control Technologies (Step 3)

The remaining technically feasible control is the use of good combustion practices.

5.26.5 Evaluation of Most Stringent Control Technologies (Step 4)

Per the RBLC filtered search results, the use of good combustion practices has been designated as BACT for several small emergency diesel generators. As good combustion practices are part of engine use and are not add-on controls, no additional costs or impacts are associated with their use.

5.26.6 Selection of BACT (Step 5)

BMOP proposes the use of good combustion practices as GHG BACT. BMOP will demonstrate compliance with the work practice standard by keeping records of maintenance performed on the engines.

5.27 GHG BACT – Small Non-Emergency Diesel Crane Engines

5.27.1 Background on Pollutant Formation

GHG formation from fuel combustion is discussed in Section 5.24.1.

5.27.2 Identification of Potential Control Technologies (Step 1)

The following GHG control technologies have been identified:

- Low carbon fuels
- Good combustion practices
- Carbon capture and storage (CCS)
- CH_4 oxidation catalyst
- N_2O catalytic reduction

These combustion technologies are discussed in greater detail in Section 5.24.2.

5.27.3 Elimination of Technically Infeasible Control Options (Step 2)

5.27.3.1 Low Carbon Fuels

The engines are authorized to fire diesel, which has a higher carbon intensity than natural gas. However, the WC 509 Platform Complex does not have the capacity to store natural gas, and the cranes may be necessary even during natural gas outages for intermittent use, and particularly if deliveries and/or work on the platform was required to restore natural gas supply. Thus, the use of natural gas as a low carbon fuel is considered technically infeasible.

5.27.3.2 Good Combustion Practices

Good combustion practices allow equipment to operate as efficiently as possible to maintain optimal emission release conditions from the engine. This is considered technically feasible for the control of GHG emissions from the engines.

5.27.3.3 CCS

As discussed in Section 5.24.3.3, the additional storage and energy requirements associated with the implementation of a CCS system at the WC 509 Platform Complex make this control technically infeasible.

5.27.3.4 CH_4 Oxidation Catalyst

As discussed in Section 5.24.3.4, the higher catalytic temperature requirements for CH_4 oxidation and vulnerability to fouling from SO_2 and water vapor exposure make this control technically infeasible.

5.27.3.5 N_2O Catalytic Reduction

As discussed in Section 5.24.3.5, the additional costs and space requirements needed for the implementation of N_2O catalytic reduction at the WC 509 Platform complex make this control technically infeasible.

5.27.4 Rank of Remaining Control Technologies (Step 3)

The remaining technically feasible control is the use of good combustion practices.

5.27.5 Evaluation of Most Stringent Control Technologies (Step 4)

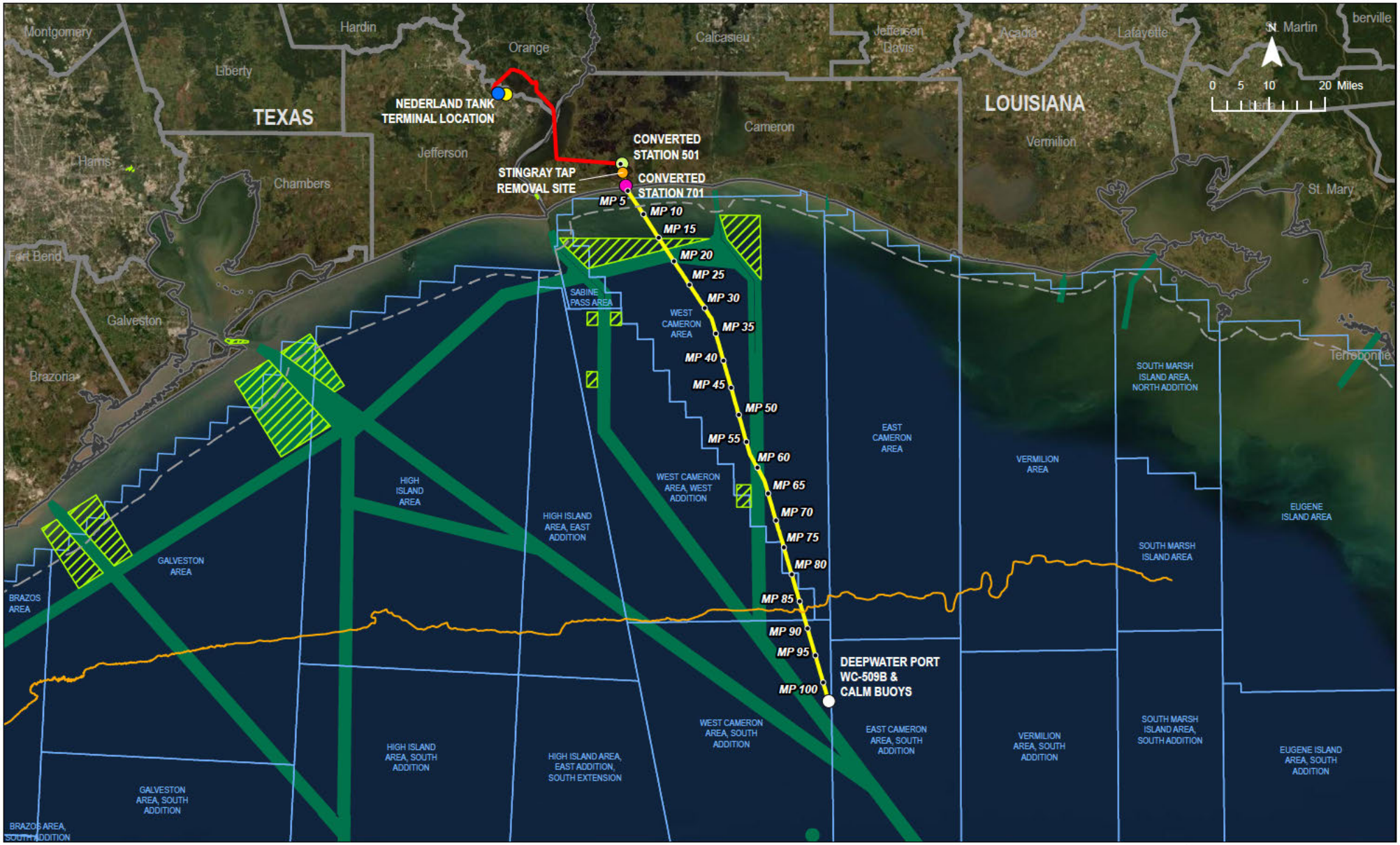
Per the RBLC filtered search results, the use of good combustion practices has been designated as BACT for several small non-emergency diesel engines. As good combustion practices are part of engine use and are not add-on controls, no additional costs or impacts are associated with their use.

5.27.6 Selection of BACT (Step 5)

BMOP proposes the use of good combustion practices as GHG BACT. BMOP will demonstrate compliance with the work practice standard by keeping records of maintenance performed on the engines.

APPENDIX A. SITE MAPS AND PLOT PLANS

BMOP PROJECT - APPENDIX A FIGURE 1 - PROJECT OVERVIEW MAP



LEGEND

- EXISTING OFFSHORE PIPELINE MILEPOSTS
- STINGRAY TAP REMOVAL SITE
- NEDERLAND TANK TERMINAL LOCATION
- NEDERLAND PUMP STATION
- CONVERTED STATION 701
- CONVERTED STATION 501
- DEEPWATER PORT WC-509B AND CALM BUOYS
- PIPELINE PORTION CONVERTED TO OIL SERVICE
- PROPOSED ONSHORE PIPELINE (NEW BUILD)
- DEPTH CONTOUR -108'
- STATE WATERS BOUNDARY
- SAFETY ANCHORAGES
- PROTRACTION AREA
- SHIPPING FAIRWAY
- COUNTY / PARISH
- STATE BOUNDARY

BLUE MARLIN OFFSHORE PORT PROJECT

PROJECT OVERVIEW MAP

COUNTY/PAR SH	VARIOUS	DRAWN BY	JRA
STATE	TX/LA	CHECKED BY	CW

REV. NO.	REVISION	DATE
A	ISSUE FOR REVIEW	2020 07/28

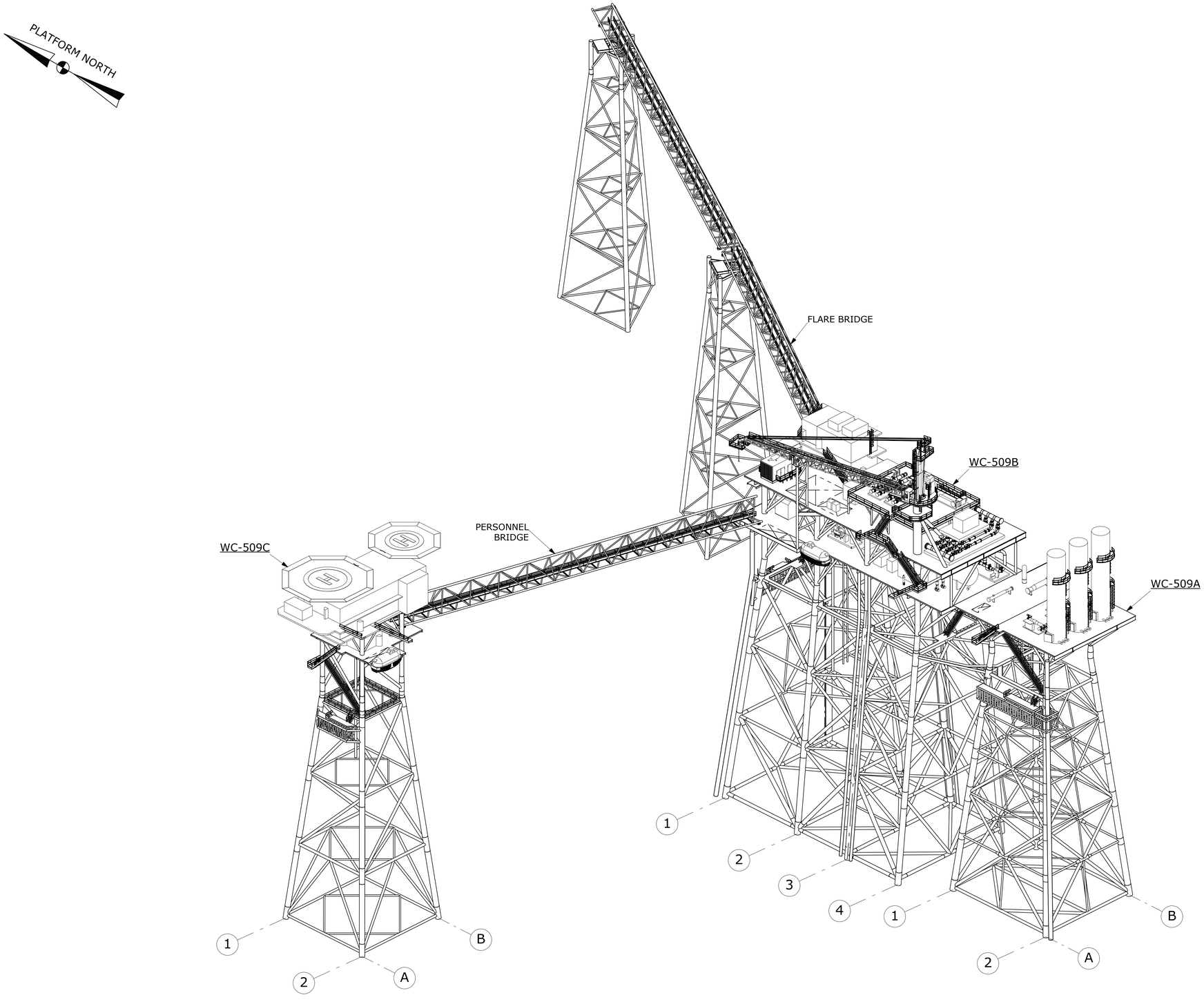
DATE	2020/07 28	PROJECTION	NAD 1983 UTM Zone 15N

PREPARED BY

EXP Energy Services Inc.
T +1.850.385.5441
F +1.850.385.5523
1800 WEST LOOP SOUTH SUITE 850
HOUSTON TX 77027 USA

BLUE MARLIN OFFSHORE PORT PROJECT
APPENDIX A FIGURE 1

DWG	0802-01-005	SHEET	1 OF 1



WOOD GROUP USA, INC.
TEXAS REGISTERED ENGINEERING FIRM F-2999
PROJECT NO: 245040

REFERENCE DRAWINGS

REV	DESCRIPTION	BY	DATE	CHK'D	APP'D
0A	ISSUED FOR REVIEW	BB	15DEC22	ET	HM
0	ISSUED FOR PERMIT	CRS	11AUG20	DD	HM
B	ISSUED FOR REVIEW	CRS	31JUL20	DD	HM
A	ISSUED FOR INTERDISCIPLINARY CHECK	CRS	17JUL20	DD	HM

FACILITY CODE OR ACCOUNT NO:
CONSTRUCTION YEAR:

	BY	DATE
DRAWN	BB	15DEC22
CHECK	ET	15DEC22
APPROVED	CN/HM	15DEC22

SCALE: N.T.S.

BLUE MARLIN OFFSHORE PORT LLC
GENERAL ARRANGEMENT
OVERALL PERSPECTIVE
WC-509 COMPLEX

AFE NO.

OLD DRAWING NO.

DRAWING NO. 245040-PIP-DWG-1000-010

REV. NO. 0A

APPENDIX B. LDEQ FORMS

Department of Environmental Quality Office of Environmental Services Air Permits Division P.O. Box 4313 Baton Rouge, LA 70821-4313 (225) 219-3417	**LOUISIANA** **Application for Approval of Emissions of Air Pollutants from Part 70 Sources**	DEQ LOUISIANA

PLEASE TYPE OR PRINT

1. Facility Information [LAC 33:III.517.D.1]

Facility Name or Process Unit Name (if any) Blue Marlin Offshore Port LLC – Deepwater Port (BMOP DWP)	☒ All Process Units ☐ Process Unit-specific Permit
Agency Interest Number (A.I. Number) 225545	**Currently Effective Permit Number(s)** N/A – New Facility
Company - Name of Owner Blue Marlin Offshore Port LLC	
Company - Name of Operator (if different from Owner) N/A	
Parent Company (if Company – Name of Owner given above is a division) Energy Transfer	
Federal Tax-ID	

☒ corporation, partnership, or sole proprietorship ☐ regulated utility ☐ municipal government

☐ state government ☐ federal government ☐ other, specify _____

2. Physical Location and Process Description [LAC 33:III.517.D.18, unless otherwise stated]

What does this facility produce? Add more rows as necessary.

The BMOP DWP will receive crude oil from existing facilities on the US mainland and load the crude oil into very large crude carriers (VLCCs) and other crude carriers for export to the global market.
Refer to section 1 of this application for detailed description.

What modifications/changes are proposed in this application? Add more rows as necessary.

Refer to section 1 of this application.

Nearest town (in the same parish as the facility): Cameron

Parish(es) where facility is located: Offshore Facility – West Cameron area, lease block 509

Distance To (mi):	115 Texas	315 Arkansas	240 Mississippi	300 Alabama
Latitude of Facility Front Gate:	28 Deg	26 Min	0.01 Sec	____ Hundredths
Longitude of Facility Front Gate:	93 Deg	0 Min	15.23 Sec	____ Hundredths
Distance from nearest Class I Area:	385	kilometers		

Add physical address and description of location of the facility below. If the facility has no address, provide driving directions. Add more rows as necessary.

The BMOP DWP will be located in federal waters within and adjacent to the Outer Continental Shelf (OCS) in West Cameron Lease Block (WC) 509 and 508 and East Cameron Block 263. The BMOP DWP will be approximately eighty-two (82) nautical miles off the coast of Cameron Parish, Louisiana, with an approximate water depth of 162 feet.

☒ Map attached (required per LAC 33:III.517.D.1)
☒ Description of processes and products attached (required per LAC 33:III.517.D.2)
☒ Introduction/Description of the proposed project attached (required per LAC 33:III.517.D.5)

3. Confidentiality [LAC 33.I.Chapter 5]

Are you requesting confidentiality for any information except air pollutant emission rates? ☒ Yes ☐ No

If "yes," list the sections for which confidentiality is requested below. Add rows as necessary. Confidentiality requests require a submittal that is separate from this application. Information for which confidentiality is requested should not be submitted with this application. Consult instructions.

Appendix D (BACT Supporting Documentation) of the Prevention of Significant Deterioration Air Construction Permit Application Volume 1

4. Type of Application [LAC 33:III.517.D]

Check all that apply.

☐ Renewal
Select one, if applicable: ☒ Entirely new facility ☐ Significant modification of existing facility (may also include reconciliations) [LAC 33:III.527] ☐ Minor modification of existing facility (may also include reconciliations) [LAC 33:III.525] ☐ Reconciliation only
NSR Analysis: ☒ Prevention of Significant Deterioration (PSD) ☐ Nonattainment New Source Review (NNSR)

Does this submittal update or replace an application currently under review? ☒ Yes ☐ No

If yes, provide date that the prior application was submitted: September 2020

Select one if this application is for an existing facility that does not have an air quality permit:

☐ Previously Grandfathered (LAC 33:III.501.B.6)
☐ Previously Exempted (e.g., Small Source Exemption; LAC 33:III.501.B.2.d)
☐ Previously Unpermitted

5. Fee Information [LAC 33:III.517.D.17]

Fee Parameter: If the fee code is based on an operational parameter (such as number of employees or capital cost), enter that parameter here. _____

Industrial Category: Enter the Standard Industrial Classification (SIC) and North American Industry Classification (NAICS) Codes that apply to the facility.

Primary SICC: 4612 **NAICS Code:** 486110

Secondary SICC(s): _____

Project Fee Calculation: Enter fee code, permit type, production capacity/throughput, and fee amount pursuant to LAC 33:III.Chapter 2. Add rows to this table as needed. Include with the application the amount in the Grand Total blank as the permit application fee.

FEE CODE	TYPE	EXISTING CAPACITY	INCREMENTAL CAPACITY INCREASE	*SURCHARGES*				
				MULTIPLIER	NSPS	PSD	AIR TOXICS	TOTAL AMOUNT
					☐	☐	☐	$
					☐	☐	☐	$
					GRAND TOTAL			$

Optional **Fee Explanation:** Use the space provided to give an explanation of the fee determination displayed above. Using this area will help to avoid confusion.

Electronic Fund Transfer (EFT): If paying the permit application fee using an Electronic Fund Transfer (EFT), please include the EFT Transaction Number, the Date that the EFT was made, and the total dollar amount submitted in the EFT. If not paying the permit application fee using EFT, leave blank.

EFT Transaction Number	Date of Submittal	Total Dollar Amount
		$

6. Key Dates

Estimated date construction will commence: March 2024 *Estimated date operation will commence:* Oct. 2026

7. Pending Permit Applications – For Process Unit-Specific Permits Only [LAC 33:III.517.D.18]

List all other process units at this facility for which Part 70 permit applications have been submitted, but have not been acted upon by LDEQ as of the date of submittal of this application. If none, state "none" in the table. *****It is not necessary to update this table during the permit review process, unless requested by LDEQ.*****

Process Unit Name	Permit Number	Date Submitted
N/A		

8. LAC 33:I.1701 Requirements – Answer all below for new sources and permit renewals - ☒ Yes ☐ No

Does the company or owner have federal or state environmental permits identical to, or of a similar nature to, the permit for which you are applying in Louisiana or other states? (This requirement applies to all individuals, partnerships, corporations, or other entities who own a controlling interest of 50% or more in your company, or who participate in the environmental management of the facility for an entity applying for the permit or an ownership interest in the permit.)
☐ **Yes** ☒ **No**

If yes, list States:

Do you owe any outstanding fees or final penalties to the Department? ☐ **Yes** ☒ **No**
If yes, explain below. Add rows if necessary.

Is your company a corporation or limited liability company? ☒ **Yes** ☐ **No**
If yes, attach a copy of your company's Certificate of Registration and/or Certificate of Good Standing from the Secretary of State. The appropriate certificate(s) should be attached to the end of this application as an appendix.

9. Permit Shield Request [LAC 33:III.517.E.7] - ☒ Yes ☐ No

See Section 1 of the Title V Air Operating Permit Application for the Permit Shield Request

If yes, check the appropriate boxes to indicate the type of permit shield being sought. Include the specific regulatory citation(s) for which the shield is being requested. Give an explanation of the circumstances that will justify the permit shield request. Attach additional pages if necessary. If additional pages are used, attach them directly behind this page and enter "See Attached Pages" into the Explanation field.

Type of Permit Shield request (check all that apply):

Non-applicability determination for:	Specific Citation(s)	Explanation
☐ 40 CFR 60		
☐ 40 CFR 61		
☐ 40 CFR 63		
☐ Prevention of Significant Deterioration		
☐ Nonattainment New Source Review		

Interpretation of monitoring, recordkeeping, and/or reporting requirements, and/or means of compliance for:	Specific Citation(s)	Explanation
☐ 40 CFR 60		
☐ 40 CFR 61		
☐ 40 CFR 63		
☐ Prevention of Significant Deterioration		
☐ Nonattainment New Source Review		
☐ State Implementation Plan (SIP) Regulation(s) referenced in 40 CFR 52 Subpart T		

10. Certification of Compliance With Applicable Requirements

Statement for Applicable Requirements for Which the Company and Facility Referenced In This Application Is In Compliance

Based on information and belief, formed after reasonable inquiry, the company and facility referenced in this application is in compliance with and will continue to comply with all applicable requirements pertaining to the sources covered by the permit application, as outlined in Tables 1 and 2 in the permit application. For requirements promulgated as of the date of this certification with compliance dates effective during the permit term, I further certify that the company and facility referenced in this application will comply with such requirements on a timely basis and will continue to comply with such requirements.

For corporations only: By signing this form, I certify that, in accordance with the definition of Responsible Official found in LAC 33:III.502, **(1)** I am a president, secretary, treasurer, or vice-president in charge of a principal business function, or other person who performs similar policy or decision-making functions; or **(2)** I am a duly authorized representative of such person; am responsible for the overall operation of one or more manufacturing, production, or operating facilities addressed in this permit application; and either the facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or the delegation of authority has been approved by LDEQ prior to this certification.*

CERTIFICATION: I certify, under provisions in Louisiana and United States law which provide criminal penalties for false statements, that based on information and belief formed after reasonable inquiry, the statements and information contained in this Application for Approval of Emissions of Air Pollutants from Part 70 Sources, including all attachments thereto and the compliance statement above, are true, accurate, and complete.

a. Responsible Official		
Name Gregory Mcilwain		
Title SVP - Operations		
Company Energy Transfer		
Suite, mail drop, or division		
Street or P.O. Box 1300 Main Street		
City Houston	State TX	Zip 77002
Business phone (713) 989-7120		
Email Address Gregory.mcilwain@energytransfer.com		

Signature of responsible official (See 40 CFR 70.2):
Date: 4/14/23

*Approval of a delegation of authority can be requested by completing a Duly Authorized Representative Designation Form (Form_7218) available on LDEQ's website at http://deq.louisiana.gov/page/air-permit-applications

CERTIFICATION: I certify that the engineering calculations, drawings, and design are true and accurate to the best of my knowledge.

b. Professional Engineer		
Name Mallorie A. Lefante, P.E.		
Title Senior Consultant		
Company Trinity Consultants Inc.		
Suite, mail drop, or division Suite 1030		
Street or P.O. Box One Galleria Blvd.		
City Metairie	State LA	Zip 70001
Business phone (504) 559-7704		
Email Address mlefante@trinityconsultants.com		

Signature of Professional Engineer:
Date: 4/14/2023
Louisiana Registration No.

STATE OF LOUISIANA
MALLORIE A. LEFANTE
License No. 40331
PROFESSIONAL ENGINEER IN ENVIRONMENTAL ENGINEERING

11. Personnel [LAC 33:III.517.D.1]

a. Manager of Facility who is located at plant site*		
Name	☐Primary contact	
Title		
Company		
Suite, mail drop, or division		
Street or P.O. Box		
City	**State**	**Zip**
Business phone		
Email address		

*No "on-site" person will be present on the offshore platform.

b. On-site contact regarding air pollution control*		
Name	☐Primary contact	
Title		
Company		
Suite, mail drop, or division		
Street or P.O. Box		
City	**State**	**Zip**
Business phone		
Email address		

*No "on-site" person will be present on the offshore platform.

c. Person to contact with written correspondence		
Name Lisa M. Garcia, P.E.	☒Primary contact	
Title Sr. Manager - Engineering		
Company Energy Transfer		
Suite, mail drop, or division		
Street or P.O. Box 1300 Main Street		
City Houston	**State** TX	**Zip** 77002
Business phone (713) 989-7762		
Email address Lisa.Garcia@energytransfer.com		

d. Person who prepared this report		
Name Michael Ballenger, P.E.	☐Primary contact	
Title Manager of Consulting Services		
Company Trinity Consultants Inc.		
Suite, mail drop, or division B		
Street or P.O. Box 919 Lake Baldwin Ln		
City Orlando	**State** FL	**Zip** 32814
Business phone (407) 982-2891 Ext.1901		
Email address mballenger@trinityconsultants.com		

e. Person to contact about Annual Maintenance Fees	☐ a ☐ b ☒ c ☐ d ☐ other (specify below)		
Name	☐Primary contact	**Suite, mail drop, or division**	
Title		**Street or P.O. Box**	
Company		**City**	**State** / **Zip**
Business Phone		**Email Address**	

12. Proposed Project Emissions [LAC 33:III.517.D.3]

List the total emissions following the proposed project for this facility or process unit (for process unit-specific permits). Speciate all criteria pollutants, TAP, and HAP for the proposed project.

Pollutant	Proposed Emission Rate (tons/yr)
Particulate matter (PM_{10})	16.00
Particulate matter ($PM_{2.5}$)	16.00
Nitrogen oxides	448.79
Carbon monoxide	817.25
Sulfur dioxide	14.66
Total VOC	2,473
CO_2e	494,797
Sulfuric Acid	0.05
Hydrogen sulfide	1.04
Total HAPs*	143.90

* Please see Appendix B for detailed list of HAPs and TAPs.

13. History of Permitted Emissions [LAC 33:III.517.D.18]

List each of the following in chronological order:

- The Permit Number and Date Action Issued for each air quality permit that has been issued to this facility or process unit (for process unit-specific permits) within the last ten (10) years.
- All small source exemptions, authorizations to construct, administrative amendments, case-by-case insignificant activities, and changes of tank service that have been approved since the currently effective Title V Operating Permit or State Operating Permit was issued to this facility or process unit (for process unit-specific permits). It is not necessary to list any such activities issued prior to the issuance of the currently effective Title V Operating Permit or State Operating Permit, if one exists.

Permit Number	Date Action Issued
N/A – New Facility	

14.a. Enforcement Actions [LAC 33:III.517.D.18] - ☐ Yes ☒ No

If yes, list all federal and state air quality enforcement actions, settlement agreements, and consent decrees received for this facility and/or process unit (for process unit-specific permits) since the issuance of the currently effective Title V Operating Permit or State Operating Permit. For each action, list the type of action (or its tracking number), the regulatory authority or authorities that issued the action, and the date that the action was issued. Summarize the conditions imposed by the enforcement action, settlement agreement, and consent decree in Section 22, Table 2. It is not necessary to submit a copy of the referenced action. Add rows to table as necessary.

Type of Action or Tracking Number	Issuing Authority	Date Action Issued	Summary of Conditions Included?
			☐ Yes ☐ No
			☐ Yes ☐ No

14.b. Schedule for Compliance [LAC 33:III.517.E.4] ☐ Yes ☒ No

If the facility or process unit for which application is being made is not in full compliance with all applicable regulations, give a description of how compliance will be achieved, including a schedule for compliance below. Add rows as necessary. See instructions.

15. Letters of Approval for Alternate Methods of Compliance - ☐ Yes ☒ No

If yes, list all correspondence with LDEQ, EPA, or other regulatory bodies that provides for or supports a request for alternate methods of compliance with any applicable regulations for this facility or process unit (for process unit-specific permits). List the date of issuance of the letter and the regulation referenced by the letter. **Attach as an appendix a copy of all documents referenced in this table.** Letters that are not included may not be incorporated into a final permit. Add rows to table as necessary.

Date Letter Issued	Issuing Authority	Referenced Regulation(s)	Copy of Letter Attached?
			☐ Yes ☐ No
			☐ Yes ☐ No
			☐ Yes ☐ No
			☐ Yes ☐ No

16. Initial Notifications and Performance Tests [LAC 33:III.517.D.18] - ☐ Yes ☒ No

If yes, list any initial notifications that have been submitted or one-time performance tests that have been performed for this facility or process unit (for process unit-specific permits) since the issuance of the currently effective Title V Operating Permit or State Operating Permit in order to satisfy regulatory requirements. Any initial notification or one-time performance test requirements that have not been satisfied should be listed in Section 22, Table 2 of this application. Any notifications or performance tests that recur periodically should also be properly noted in Section 22, Table 2 of this application. Add rows to table as necessary.

Initial Notification or One-time Performance Test?	Regulatory Citation Satisfied	Applicable Source(s)	Date Completed/Approved

17. Existing Prevention of Significant Deterioration or Nonattainment New Source Review Limitations [LAC 33:III.517.D.18]

Do one or more emissions sources represented in this permit application currently operate under one or more NSR permits?
☐ **Yes** ☒ **No**

If "yes," summarize the limitations from such permit(s) in the following table. Add rows to table as necessary. Be sure to note any annual emissions limitations from such permit(s) in Section 13 of this application.

Permit Number	Date Issued	Emission Point ID No.	Pollutant	BACT/LAER Limit[1]	Averaging Period	Description of Control Technology/Work Practice Standards

[1]For example, lb/MM Btu, ppmvd @ 15% O_2, lb/ton, lb/hr

18. Air Quality Dispersion Modeling [LAC 33:III.517.D.15]

Was Air Quality Dispersion Modeling as required by LAC 33:III performed in support of this permit application? (Air Quality Dispersion Modeling is only required when applying for PSD permits and as requested by LDEQ.)
☒ **Yes** ☐ **No**

*Has Air Quality Dispersion Modeling completed in accordance with LAC 33:III ever been performed for this facility in support of an air permit application previously submitted for this facility or process unit (for process unit-specific permits) or as required by other regulations **AND** approved by LDEQ?*
☐ **Yes** ☒ **No**

If yes, enter the date the most recent Air Quality Dispersion Modeling results as required by LAC 33:III were submitted:

_____

If the answer to either question above is "yes," enter a summary of the most recent results in the following table. If the answer to both questions is "no," enter "none" in the table. Add rows to table as necessary.

Pollutant	Time Period	Calculated Maximum Ground Level Concentration	Louisiana Toxic Air Pollutant Ambient Air Standard or (National Ambient Air Quality Standard {NAAQS})
Refer to the PSD Air Construction Permit Application Volume 2			

19. General Condition XVII Activities- ☐ Yes ☒ No

Enter all activities that qualify as Louisiana Air Emissions Permit General Condition XVII Activities.

- Expand this table as necessary to include all such activities.
- See instructions to determine what qualifies as a General Condition XVII Activity.
- Do not include emissions from General Condition XVII Activities in the proposed emissions totals for the permit application.

		Emission Rates – TPY					
Work Activity	**Schedule**	**PM_{10}**	**SO_2**	**NO_x**	**CO**	**VOC**	**Other**

20. Insignificant Activities [LAC 33:III.501.B.5] - ☒ Yes ☐ No

Enter all activities that qualify as Insignificant Activities.

- Expand this table as necessary to include all such activities.
- For sources claimed to be insignificant based on size or emission rate (LAC 33:III.501.B.5.A), information must be supplied to verify each claim. This may include but is not limited to operating hours, volumes, and heat input ratings.
- If aggregate emissions from all similar pieces of equipment claimed to be insignificant are greater than 5 tons per year for any pollutant, then the activities can not be claimed as insignificant and must be represented as permitted emission sources. Aggregate emissions shall mean the total emissions from a particular insignificant activity or group of similar insignificant activities (e.g., A.1, A.2, etc.) within a permit per year.

Emission Point ID No.	Description	Physical/Operating Data	Citation
AFST	Aviation Fuel Storage Tank	3,000 Gallons	LAC 33:III.501.B.5.A.3
CDT1	Crane Diesel Tank No. 1	3,000 Gallons	LAC 33:III.501.B.5.A.3
CDT2	Crane Diesel Tank No. 2	3,000 Gallons	LAC 33:III.501.B.5.A.3

21. Regulatory Applicability for Commonly Applicable Regulations – Answer all below [LAC 33:III.517.D.10]

Does this facility contain asbestos or asbestos containing materials? ☐ **Yes** ☒ **No**
If "yes," the facility or any portion thereof may be subject to 40 CFR 61, Subpart M, LAC 33:III.Chapter 27, and/or LAC 33:III.5151, and this application must address compliance as stated in Section 22 of this application

Is the facility or process unit represented in this permit subject to 40 CFR 68, or is any other process unit located at the same facility as the process unit represented in this application subject to 40 CFR 68? ☐ **Yes** ☒ **No**
If "yes," the entire facility is subject to 40 CFR 68 and LAC 33:III.Chapter 59, and this application must address compliance as stated in Section 22 of this application.

Is the facility listed in LAC 33:III.5611?

Table 5 ☐ **Yes** ☒ **No**

Table 6 ☐ **Yes** ☒ **No**

Table 7 ☐ **Yes** ☒ **No**

Does the applicant own or operate commercial refrigeration equipment normally containing more than 50 pounds of refrigerant at this facility or process unit? ☐ **Yes** ☒ **No**
If "yes," the entire facility is subject to 40 CFR 82, Subpart F, and this application must address compliance as stated in Section 22 of this application.

22. Applicable Regulations, Air Pollution Control Measures, Monitoring, and Recordkeeping

Important points for Table 1 [LAC 33:III.517.D.10]:

- List in Table 1, by Emission Point ID Number and Descriptive Name of the Equipment, state and federal pollution abatement programs and note the applicability or non-applicability of the regulations to each source.
- Adjust the headings for the columns in Table 1 as necessary to reflect all applicable regulations, in addition to any regulations that do not apply but require an explanation to substantiate this fact.
- For each piece of equipment, enter "1" for each regulation that applies. Enter "2" for each regulation that applies to this type of source, but from which this source of emissions is exempt. Enter "3" for equipment that is subject to a regulation, but does not have any applicable requirements. Also, enter "3" for each regulation that has applicable requirements that apply to the particular emission source, but the regulations currently do not apply due to meeting a specific criterion, such as it has not been constructed, modified, or reconstructed since the regulations have been in place.
- Leave the spaces blank when the regulations clearly would not apply under any circumstances to the source. For example, LAC 33:III.2103 – Storage of Volatile Organic Compounds would never apply to a steam generating boiler, no matter the circumstances.
- Consult instructions.

Important points for Table 2 [LAC 33:III.517.D.4; LAC 33:III.517.D.7; LAC 33:III.517.D.10]:

- For each piece of equipment listed in Table 2, include all applicable limitations, recordkeeping, reporting, monitoring, and testing requirements. Also, include any one-time notification or one-time performance test requirements that have not been fulfilled.
- Each of these regulatory aspects (limitations, recordkeeping, reporting, etc.) should be addressed for each regulation that is applicable to each emissions source or emissions point.
- For each regulation that provides a choice regarding the method of compliance, indicate the method of compliance that will be employed. It is not sufficient to state that all compliance options will be employed, though multiple compliance options may be approved as alternative operating scenarios.
- Consult instructions.

Important points for Table 3 [LAC 33:III.517.D.16]:

- Each time a 2 or a 3 is used to describe applicability of a source in Table 1, an entry should be made in Table 3 that explains the exemption or non-applicability status of the regulation to that source.
- Fill in all requested information in the table.
- The exact regulatory citation that provides for the specific exemption or non-applicability determination should be entered into the "Citation Providing for Exemption or Non-applicability" column.
- Consult Instructions.

Important points for Table 4 [LAC 33:III.517.D.18]

- List any single emission source that routes its emissions to another point where these emissions are commingled with the emissions of other sources before being released to the atmosphere. Do not list any single emission source in this table that does not route its emissions in this manner.
- List any and all emission sources that are routed as described above. This includes emission sources that do not otherwise appear in this permit application.
- Consult instructions.

TABLE 1: APPLICABLE LOUISIANA AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point	Description	LAC 33.III							LAC 33.III.Chapter									
		509	2103	2108	2111	2113	2115	2121	2	5	9	11	13	15	22	51	56	59
BMOP DWP Facility	BMOP DWP Facility	1		3		1		3	1	1	1	1	1	3		1	1	3
LPFL	Low Pressure Flare - Vapor Capture											1	1	3				
HPFL	High Pressure Flare - Natural Gas											1	1	3				
NGGEN1	Natural Gas Generator #1											2	1	3				
NGGEN2	Natural Gas Generator #2											2	1	3				
NGGEN CAP	Natural Gas Generators CAP																	
BCRANE1	Platform B Crane #1 (Diesel)											1	1	3		3		
BCRANE2	Platform B Crane #2 (Diesel)											1	1	3		3		
DGEN	Emergency Diesel Generator											1	1	3		3		
BFWP	Platform B Firewater Pump (Diesel)											1	1	3		3		
CFWP	Platform C Firewater Pump (Diesel)											1	1	3		3		
PDST	Primary Diesel Storage Tank		3															
SRGT	Surge Tank		2															
FUG	Facility Wide Fugitives				1			3								1		
UNLD1	Uncaptured Loading at Buoy #1																	
UNLD2	Uncaptured Loading at Buoy #2																	
UNLD CAP	Uncaptured Loading CAP																	
VCU1	VCU Stack 1											1	1	3				
VCU2	VCU Stack 2											1	1	3				
VCU3	VCU Stack 3											1	1	3				

KEY TO MATRIX

1 (Applicable) The regulations have applicable requirements that apply to this particular emissions source This includes any monitoring, recordkeeping, or reporting requirements
2 (Exempt) The regulations apply to this general type of emission source (i e vents, furnaces, towers, and fugitives) but do not apply to this particular emission source
3 (Does Not Apply) The regulations do not apply to this emissions source The regulations may have applicable requirements that could apply to this emissions source but the requirements do not currently apply to the source due to meeting a specific criterion, such as it has not been constructed, modified or reconstructed since the regulations have been in place

TABLE 1: APPLICABLE LOUISIANA AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point	Description	40 C.F.R. Part 60 NSPS							40 C.F.R. Part 61 NESHAP	40 C.F.R. Part 63 NESHAP							40 C.F.R. Part			
		A	K	Ka	Kb	IIII	JJJJ	OOOOa	V	A	H	Y	HH	VV	EEEE	ZZZZ	64	68	72	82
BMOP DWP Facility	BMOP DWP Facility	1						3	3	1	3		3	3	3			3	3	1
LPFL	Low Pressure Flare - Vapor Capture																			
HPFL	High Pressure Flare - Natural Gas																			
NGGEN1	Natural Gas Generator #1	1					1			1						1				
NGGEN2	Natural Gas Generator #2	1					1			1						1				
NGGEN CAP	Natural Gas Generators CAP																			
BCRANE1	Platform B Crane #1 (Diesel)	1				1				1						1				
BCRANE2	Platform B Crane #2 (Diesel)	1				1				1						1				
DGEN	Emergency Diesel Generator	1				1				1						1				
BFWP	Platform B Firewater Pump (Diesel)	1				1				1						1				
CFWP	Platform C Firewater Pump (Diesel)	1				1				1						1				
PDST	Primary Diesel Storage Tank		3	3	3															
SRGT	Surge Tank		3	3	3															
FUG	Facility Wide Fugitives																			
UNLD1	Uncaptured Loading at Buoy #1																			
UNLD2	Uncaptured Loading at Buoy #2																			
UNLD CAP	Uncaptured Loading CAP																			
VCU1	VCU Stack 1									1		1					3			
VCU2	VCU Stack 2									1		1					3			
VCU3	VCU Stack 3									1		1					3			

KEY TO MATRIX

1 (Applicable) The regulations have applicable requirements that apply to this particular emissions source This includes any monitoring, recordkeeping, or reporting requirements
2 (Exempt) The regulations apply to this general type of emission source (i e vents, furnaces, towers, and fugitives) but do not apply to this particular emission source
3 (Does Not Apply) The regulations do not apply to this emissions source The regulations may have applicable requirements that could apply to this emissions source but the requirements do not currently apply to the source due to meeting a specific criterion, such as it has not been constructed, modified or reconstructed since the regulations have been in place

Blank – The regulations clearly do not apply to this type of emission source

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
BMOP DWP Facility	40 C.F.R. Part 60 Subpart A - General Provisions	**Requirements that limit emissions or operations-**			
		Comply with all applicable requirements to limit emissions or operations specified in 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.11 and § 60.18	N/A	No
		Requirements that specify monitoring-			
		Comply with all applicable monitoring requirements of 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.13	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Maintain all applicable records as required by 40 C.F.R Part 60 Subpart A.	40 C.F.R. § 60.7	N/A	No
		Requirements that specify reports to be submitted-			
		Submit all applicable reports as required by 40 C.F.R. Part 60 Subpart A.	40 C.F.R § 60.7 and § 60.19	N/A	No
		Requirements that specify performance testing-			
		Conduct applicable tests according to 40 C.F.R. § 60.8.	40 C.F.R. § 60.8	N/A	No
	40 C.F.R. Part 63 Subpart A - General Provisions	**Requirements that limit emissions or operations-**			
		Comply with all applicable requirements to limit emissions or operations specified in 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.6 and § 63.11	N/A	No
		Requirements that specify monitoring-			
		Comply with all applicable monitoring requirements of 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.8	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Maintain all applicable records as required by 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.10	N/A	No
		Requirements that specify reports to be submitted-			
		Submit all applicable reports as required by 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.9 and § 63.10	N/A	No
		Requirements that specify performance testing-			
		Conduct applicable tests according to 40 C.F.R. § 63.7.	40 C.F.R. § 63.7	N/A	No
	40 C.F.R. Part 82 - Stratospheric Ozone Provisions	**Requirements that limit emissions or operations-**			
		Comply with the standards for recycling and emissions reduction pursuant to 40 C.F.R. Part 82, Subpart F, except as provided for Motor Vehicle Air Conditioners (MVACs) in Subpart B.	40 C.F.R. 82 Subpart B, E, and F	N/A	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
BMOP DWP Facility (continued)	LAC 33:III Chapter 2 - Rules and Regulations for the Fee System of the Air Quality Control Programs	**Requirements that limit emissions or operations-**			
		Shall pay the prescribed application fee or annual fee, as determined by LAC 33:III.223, within 90 days after the due date.	LAC 33:III.219	90 Days After Application Due Date	No
	LAC 33:III Chapter 9 - General Regulations on Control of Emissions and Emission Standards	**Requirements that limit emissions or operations-**			
		No person or group of persons shall allow particulate matter or gases to become airborne in amounts which cause the ambient air quality standards to be exceeded. The limits stated include normal background levels of particulates and gases.	LAC 33:III.929.A	N/A	No
		Requirements that specify reports to be submitted-			
		Submit Emission Inventory (EI)/Annual Emissions Statement: Due annually, by the 30th of April to the Office of Environmental Services, for the reporting period of the previous calendar year that coincides with period of ownership or operatorship, until released from reporting, in writing, by DEQ. Submit both an emissions inventory and the certification statement required by LAC 33:III.919.F.1.c, separately for each AI, in a format specified by DEQ. To request a release from reporting, submit a completed Request for Release from Emissions Inventory Reporting form (form# 7365) to the Office of Environmental Services.	LAC 33:III.919	Annually	No
		Shall report the unauthorized discharge of any air pollutant into the atmosphere in accordance with LAC 33:I.Chapter 39. Submit written reports to the department pursuant to LAC 33:I.3925. Submit timely and appropriate follow-up reports detailing methods to be used to prevent similar atmospheric releases.	LAC 33:III.927	Upon Occurrence of an Unauthorized Discharge	No
		Requirements that specify performance testing-			
		New sources shall provide necessary sampling ports in stacks or ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices as may be necessary for proper determination of the emission of air contaminants.	LAC 33:III.913	N/A	No
	LAC 33:III Chapter 11 - Control of Emissions of Smoke	**Requirements that limit emissions or operations-**			
		Emissions of smoke which pass onto or across a public road and create a traffic hazard by impairing visibility as defined in LAC 33:III.111 or intensifying an existing traffic hazard condition are prohibited.	LAC 33:III.1103	N/A	No
	LAC 33:III Chapter 13 - Emission Standards for Particulate Matter	**Requirements that limit emissions or operations-**			
		Emissions of particulate matter which pass onto or across a public road and create a traffic hazard by impairment of visibility or intensify an existing traffic hazard condition are prohibited.	LAC 33:III.1303.B	N/A	No
	LAC 33:III Chapter 21 - Control of Emission of Organic Compounds	**Requirements that limit emissions or operations-**			
		Maintain best practical housekeeping and maintenance practices at the highest possible standards to reduce the quantity of organic compounds emissions. Good housekeeping shall include, but not be limited to, the practices listed in LAC 33:III.2113.A.1-5.	LAC 33:III.2113.A	N/A	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
BMOP DWP Facility (continued)	LAC 33:III Chapter 56 - Prevention of Air Pollution Emergency Episodes	**Requirements that limit emissions or operations-**			
		During an Air Pollution Alert, Air Pollution Warning or Air Pollution Emergency, make the standby plan available on the premises to any person authorized by DEQ to enforce these regulations.	LAC 33:III.5611.B.1	N/A	No
LPFL - Low Pressure Flare - Vapor Capture HPFL - High Pressure Flare - Natural Gas	LAC 33:III Chapter 11 - Control of Emissions of Smoke	**Requirements that limit emissions or operations-**			
		Opacity <= 20 percent; except for a combined total of six hours in any 10 consecutive day period, for burning in connection with pressure valve releases for control over process upsets.	LAC 33:III.1105	N/A	No
		Requirements that specify reports to be submitted-			
		Submit notification: Due to SPOC as soon as possible after the start of burning of pressure valve releases for control over process upsets. Notify in accordance with LAC 33:I.3923. Notification is required only if the upset cannot be controlled in six hours.	LAC 33:III.1105	N/A	No
	LAC 33:III.Chapter 13 - Emission Standards for Particulate Matter	**Requirements that limit emissions or operations-**			
		Opacity <= 20 percent; except emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.	LAC 33:III.1311.C	Six-minute	No
NGGEN1 - Natural Gas Generator #1 (2,328 hp) NGGEN2 - Natural Gas Generator #2 (2,328 hp)	40 CFR 60 Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines	**Requirements that limit emissions or operations-**			
		(Excluding Formaldehyde) VOC Total <= 0.7 g/hp-hr (60 ppmdv at 15%	40 CFR 60.4233(e)	N/A	No
		Carbon monoxide (CO) <= 2.0 g/hp-hr (270 ppmdv at 15% O_2).	40 CFR 60.4233(e)	N/A	No
		Nitrogen oxides (NO_X) <= 1.0 g/hp-hr (82 ppmdv at 15% O_2).	40 CFR 60.4233(e)	N/A	No
		Operate and maintain stationary SI ICE to achieve the emission standards as required in 40 CFR 60.4233 over the entire life of the engine.	40 CFR 60.4234	N/A	No
		Purchase a non-certified engine and demonstrate compliance with the emission standards specified in § 60.4233 (e) and according to the requirements specified in § 60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section.	40 CFR 60.4243(b)(2)	N/A	No
		Operate using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations. Keep records of such use. If propane is used for more than 100 hours per year and the engine is not certified to the emission standards when using propane, conduct a performance test to demonstrate compliance with the emission standards of 40 CFR 60.4233.	40 CFR 60.4243(e)	N/A	No
		Requirements that specify monitoring -			
		It is expected that air-to-fuel ratio controllers will be used with the operation of three-way catalysts/non-selective catalytic reduction. The AFR controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times.	40 CFR 60.4243(g)	Continuously	No
		Requirements that specify records to be kept and requirements that specify record retention time -			
		Keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions.	40 CF 60.4243(b)(2)(ii)	N/A	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
NGGEN1 - Natural Gas Generator #1 (2,328 hp) NGGEN2 - Natural Gas Generator #2 (2,328 hp) (continued)	40 CFR 60 Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines	Equipment/operational data recordkeeping by electronic or hard copy continuously. Keep records of the information in 40 CFR 60.4245(a)(1) through (a)(4).	40 CFR 60.4245(a)	N/A	No
		Requirements that specify reports to be submitted			
		Owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in 40 CFR 60.4231 must submit an initial notification as required in 40 CFR 60.7(a)(1). The notification must include the information in 40 CFR 60.4245(c)(1)-(5).	40 CFR 60.4245(c)	N/A	No
		Owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test as conducted in 40 CFR 60.4244 within 60 days after the test has been completed.	40 CFR 60.4245(d)	N/A	No
		Requirements that specify performance testing -			
		If the certified stationary SI internal combustion engine and control device is operated and maintained according to the manufacturer's emission-related written instructions, keep records of conducted maintenance to demonstrate compliance, but no performance testing is required. Meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply.	40 CFR 60.4243(a)(1)	N/A	No
		If the certified stationary SI internal combustion engine and control device are not maintained according to the manufacturer's emission-related written instructions, the engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(i) through (iii) of this section, as appropriate.	40 CFR 60.4243(a)(2)	N/A	No
		Purchasing a non-certified engine and demonstrating compliance with the emission standards specified in §60.4233(d) or (e) and according to the requirements specified in §60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section.	41 CFR 60.4243(b)(2)	N/A	No
		If purchasing a non-certified engine, conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance. Conduct performance tests by following the procedures in 40 CFR 60.4244(a) through (g).	40 CFR 60.4243(b)(2)(ii); 40 CFR 60.4244	Every 8,760 hours or 3 years	No
	40 CFR 63 Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	**Requirements that limit emissions or operations**-			
		A new stationary RICE located at an area source meets the requirements of this part (i.e., 40 CFR Part 63 Subpart ZZZZ) by meeting the requirements of 40 CFR Part 60, Subpart JJJJ. No further requirements apply under 40 CFR Part 63 Subpart ZZZZ.	40 CFR 63.6590(c)(1)	N/A	No
	LAC 33:III.Chapter 13 - Emission Standards for Particulate Matter	**Requirements that limit emissions or operations**-			
		Opacity <= 20 percent; except emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes. (Complies by using sweet natural gas as fuel)	LAC 33:III.1311.C	Six-minute	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
BCRANE1 - Platform B Crane #1 (475 hp, diesel) BCRANE2 - Platform B Crane #2 (475 hp, diesel)	40 C.F.R. Part 60 Subpart A - General Provisions	**Requirements that limit emissions or operations-**			
		Comply with all applicable requirements to limit emissions or operations specified in 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.11 and § 60.18	N/A	No
		Requirements that specify monitoring-			
		Comply with all applicable monitoring requirements of 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.13	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Maintain all applicable records as required by 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.7	N/A	No
		Requirements that specify reports to be submitted-			
		Submit all applicable reports as required by 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.7 and § 60.19	N/A	No
		Requirements that specify performance testing-			
		Conduct applicable tests according to 40 C.F.R. § 60.8.	40 C.F.R. § 60.8	N/A	No
	40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	**Requirements that limit emissions or operations-**			
		Shall comply with the emission standards for new CI engines in 40 CFR 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.	40 CFR 60.4204(b)	N/A	No
		Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.	40 CFR 60.4201(a)	N/A	No
		Shall operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4204 over the entire life of this engine.	40 CFR 60.4206	Entire life of the engine	No
		Beginning October 1, 2010, shall use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.	40 CFR 60.4207(b)	N/A	No
		May not import or install stationary CI ICE that do not meet the applicable requirements in 40 CFR 60.4208.	40 CFR 60.4208	N/A	No
		In addition to the requirements specified in 40 CFR 60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.	40 CFR 60.4208(h)	N/A	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
BCRANE1 - Platform B Crane #1 (475 hp, diesel) BCRANE2 - Platform B Crane #2 (475 hp, diesel) (continued)	40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (continued)	Owner or operator that must comply with the emission standards in this subpart shall do the following: - Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; - Change only those emission-related settings that are permitted by the manufacturer; and - Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply.	40 CFR 60.4211(a)(1) through (a)(3)	N/A	No
		As stated in 40 CFR 60.4218, comply with the applicable general provisions listed in Table 8.	40 CFR 60.4218; Table 8	N/A	No
		Shall comply by purchasing an engine certified to the emission standards in 40 CFR 60.4204(b) for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph 60.4211(g).	40 CFR 60.4211(c)	N/A	No
		If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions.	40 CFR 60.4211(g)	N/A	No
		Requirements that specify monitoring-			
		If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in 40 CFR 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.	40 CFR 60.4209(b)	N/A	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
BCRANE1 - Platform B Crane #1 (475 hp, diesel) BCRANE2 - Platform B Crane #2 (475 hp, diesel) (continued)	40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (continued)	**Requirements that specify records to be kept and requirements that specify record retention time-**			
		If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.	40 CFR 60.4214(c)	N/A	No
		If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must keep a maintenance plan and records of conducted maintenance.	40 CFR 60.4211(g)	N/A	No
		Requirements that specify performance testing-			
		If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the	40 CFR 60.4211(g)(2)	N/A	No
		If performance test is required: conduct performance tests by following the procedures in 40 CFR 60.4212(a) through (e).	40 CFR 60.4212	N/A	No
	40 CFR 63 Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal	**Requirements that limit emissions or operations -**			
		Meet the requirements of 40 CFR 63 by meeting the requirements of 40 CFR 60 Subpart IIII. No further requirements apply to such engines under 40 CFR 63.	40 CFR 63.6590(c)(7)	N/A	No
	LAC 33:III.Chapter 11 - Control of Emissions of Smoke	**Requirements that limit emissions or operations -**			
		Shall control the emission of smoke generated by the burning of fuel or combustion of waste material in a combustion unit, including the incineration of industrial, commercial, institutional and municipal wastes so that the shade or appearance of the emission is not darker than 20 percent average opacity, except that such emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.	LAC 33:III.1101.B	One six-minute period in any 60 consecutive minutes.	No
	LAC 33:III.Chapter 13 - Emission Standards for Particulate Matter	**Requirements that limit emissions or operations -**			
		Emissions of particulate matter shall be controlled so that the shade or appearance of the emission is not denser than 20 percent average opacity, except the emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.	LAC 33:III.1311.C	6 minutes in any 60 consecutive minutes	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
DGEN - Emergency Generator (450 hp, diesel) BFWP - Platform B Firewater Pump (650 hp, diesel) CFWP - Platform C Firewater Pump (650 hp, diesel)	40 C.F.R. Part 60 Subpart A - General Provisions	**Requirements that limit emissions or operations-**			
		Comply with all applicable requirements to limit emissions or operations specified in 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.11 and § 60.18	N/A	No
		Requirements that specify monitoring-			
		Comply with all applicable monitoring requirements of 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.13	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Maintain all applicable records as required by 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.7	N/A	No
		Requirements that specify reports to be submitted-			
		Submit all applicable reports as required by 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.7 and § 60.19	N/A	No
		Requirements that specify performance testing-			
		Conduct applicable tests according to 40 C.F.R. § 60.8.	40 C.F.R. § 60.8	N/A	No
	40 C.F.R. Part 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	**Requirements that limit emissions or operations-**			
		For the emergency generators: comply with the NMHC + NO_X, CO, and PM emission limitations set forth in Table 1 for the highest tier of the appropriate sized engine. All emergency generators are subject to the following standards: • CO limit of 3.5 g/kW-hr • PM limit of 0.20 g/kW-hr Engines greater than 560 kilowatts (kW) are subject to the following standard: • NMHC + NO_X limit of 6.4 g/kW-hr Engines with a rated power between 225-560 kW are subject to the following standard: • NMHC + NO_X limit of 4.0 g/kW-hr	40 C.F.R. § 60.4202(a)(2),40 C.F.R. § 60.4202(b)(2), 40 C.F.R. § 89.112(a) Table 1	Per underlying Test Method	No
		For the emergency generators: exhaust opacity from CI nonroad engines (excluding single-cylinder engines, propulsion marine diesel engines, and constant speed engines) may not exceed: • 20% during the acceleration mode; • 15% during the lugging mode; and • 50% during the peaks in either the acceleration or lugging modes.	40 C.F.R. § 60.4202(b)(2), 40 C.F.R. § 89.113	Per 40 C.F.R.§ 89.113	No
		For the fire pumps: comply with the NMHC + NO_X and PM emission limitations set forth in 40 C.F.R. Part 60 Subpart IIII Table 4 for 600-750 hp engines, 2009 model year and later.	40 C.F.R. § 60.4205(c), 40 C.F.R. Part 60 Subpart IIII Table 4	Per underlying Test Method	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
DGEN - Emergency Generator (450 hp, diesel) BFWP - Platform B Firewater Pump (650 hp, diesel) CFWP - Platform C Firewater Pump (650 hp, diesel) (continued)	40 C.F.R. Part 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (continued)	Operate and maintain stationary CI ICE that achieve the emission standards as required in 40 C.F.R. 60.4204 and 40 C.F.R. 60.4205 over the entire life of the engine.	40 C.F.R. § 60.4206	N/A	No
		Use diesel fuel with a maximum sulfur content of 15 ppm. Use diesel fuel with a minimum cetane index of 40 or a maximum aromatic content of 35 volume %.	40 C.F.R. § 60.4207(b), 40 C.F.R. § 80.510(b)	Continuously	No
		If the emergency stationary CI internal combustion engine does not meet the standards applicable to non-emergency engines, install a non-resettable hour meter prior to startup of the engine.	40 C.F.R. § 60.4209(a)	N/A	No
		Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions, change only those emission related settings that are permitted by the manufacturer, and meet the requirements of 40 C.F.R. Part 89, 94, and/or 1068, as they apply.	40 C.F.R. § 60.4211(a)	N/A	No
		Purchase an engine certified to the emission standards in 40 C.F.R. § 60.4204(b), § 60.4205(b), or § 60.4205(c), as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 C.F.R. § 60.4211(g).	40 C.F.R. § 60.4211(c)	N/A	No
		Operate according to the requirements in 40 C.F.R. 60.4211(f)(1), (f)(2)(i), and (f)(3). In order for the engine to be considered an emergency stationary ICE under 40 C.F.R. 60 Subpart IIII, any operation other than as described in 40 C.F.R. 60.4211(f)(1), (f)(2)(i), and (f)(3) is prohibited. If the engine is not operated according to these requirements, the engine will not be considered an emergency engine under 40 C.F.R. 60 Subpart IIII and must meet all requirements for non-emergency engines.	40 C.F.R. § 60.4211(f)	N/A	No
		There is no time limit on the use of emergency stationary ICE in emergency situations.	40 C.F.R. § 60.4211(f)(1)	N/A	No
		Operate for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, provided that the tests are recommended by the federal, state or local government; the manufacturer; the vendor; the regional transmission organization or equivalent balancing authority and transmission operator; or the insurance company associated with the engine. LDEQ may be petitioned for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if records are maintained indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.	40 C.F.R. § 60.4211(f)(2)(i)	N/A	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
DGEN - Emergency Generator (450 hp, diesel) BFWP - Platform B Firewater Pump (650 hp, diesel) CFWP - Platform C Firewater Pump (650 hp, diesel) (continued)	40 C.F.R. Part 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (continued)	Operate for up to 50 hours per calendar year in non-emergency situations. Count the 50 hours of operation in non-emergency situations as part of the 100 hours per calendar year for maintenance and testing provided in 40 C.F.R. 60.4211(f)(2)(i). Do not use the 50 hours per calendar year for non-emergency situations for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity, except as provided in 40 C.F.R. 60.4211(f)(3)(i).	40 C.F.R. § 60.4211(f)(3)	N/A	No
		Comply with applicable requirements in Table 8 to Subpart IIII of Part 60.	40 C.F.R. § 60.4218, Table 8 to Subpart IIII of Part 60	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Operating time recordkeeping by electronic or hard copy upon occurrence of event. If the emergency engine meets the standards applicable to emergency engines in the applicable model year, keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. Record the time of operation of the engine and the reason the engine was in operation during that time.	40 C.F.R. § 60.4214(b)	N/A	N/A

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
DGEN - Emergency Generator (450 hp, diesel) BFWP - Platform B Firewater Pump (650 hp, diesel) CFWP - Platform C Firewater Pump (650 hp, diesel) (continued)	40 C.F.R. Part 63 Subpart A - General Provisions	**Requirements that limit emissions or operations-**			
		Comply with all applicable requirements to limit emissions or operations specified in 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.6 and § 63.11 as per 63.6665	N/A	No
		Requirements that specify monitoring-			
		Comply with all applicable monitoring requirements of 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.8 as per 63.6665	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Maintain all applicable records as required by 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.10 as per 63.6665	N/A	No
		Requirements that specify reports to be submitted-			
		Submit all applicable reports as required by 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.9 and § 63.10 as per 63.6665	N/A	No
		Requirements that specify performance testing-			
		Conduct applicable tests according to 40 C.F.R. § 63.7.	40 C.F.R. § 63.7 as per 63.6665	N/A	No
	40 C.F.R. Part 63 Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	**Requirements that specify reports to be submitted-**			
		RICE with Capacities Greater Than 500 Horsepower: Per 40 C.F.R. § 63.6590(b)(1)(i), new emergency stationary RICE with a site rating of more than 500 brake horsepower located at a major HAP source that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 40 C.F.R. § 63.6640(f)(2)(ii) and (iii) do not have to meet the requirements of Subpart ZZZZ and Subpart A except for the initial notification requirements of 40 C.F.R. § 63.6645(f).	40 C.F.R. § 63.6590(b)(1)(i), 40 C.F.R. § 63.6645(f)	N/A	No
	LAC 33:III Chapter 11 - Control of Emissions of Smoke	**Requirements that limit emissions or operations-**			
		Opacity <= 20 percent, except for emissions that have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes. Determine opacity by using Method 9 of 40 C.F.R. Part 60, Appendix A or by using a continuous opacity monitoring system (COMS) meeting the requirements outlined in 40 C.F.R. 60.13(c) and (d).	LAC 33:III.1101.B	6 Minutes in any 60 Minute Consecutive Period	No
	LAC 33:III Chapter 13 - Emission Standards for Particulate Matter	**Requirements that limit emissions or operations-**			
		Opacity <= 20 percent, except for emissions that have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.	LAC 33:III.1311.C	6 Minutes in any 60 Minute Consecutive Period	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
FUG - Facility Wide Fugitives	LAC 33:III Chapter 2111 - Pumps And Compressors	**Requirements that limit emissions or operations-**			
		Equip all rotary pumps and compressors handling volatile organic compounds having a true vapor pressure of 1.5 psia or greater at handling conditions with mechanical seals or other equivalent equipment.	LAC 33:III.2111	N/A	No
	LAC 33:III Chapter 51 - Comprehensive Toxic Air Pollutant Emission Control Program	**Requirements that specify reports to be submitted -**			
		Emissions to be reported in facility-wide report.	LAC 33:III.5107.A	N/A	Yes
VCU1, 2, & 3 - VCU Stacks 1, 2, & 3	40 CFR 63 Subpart Y - National Emission Standards for Hazardous Air Pollutants from Marine Tank Loading Operations	**Requirements that limit emissions or operations-**			
		Operate a vapor collection system to collect HAP vapors displaced from marine tank vessels during loading operations and to prevent HAP vapors collected at one loading berth from passing through another loading berth into the atmosphere.	40 CFR 63.562(b)(1)(i)	N/A	No
		Limit marine tank vessel loading operations to vessels equipped with vapor collection equipment that is compatible with the terminal's vapor collection system.	40 CFR 63.562(b)(1)(ii)	N/A	No
		Limit marine tank vessel loading operations to vessels which are vapor tight and connected to the vapor collection system.	40 CFR 63.562(b)(1)(iii)	N/A	No
		Reduce HAP emissions from marine tank vessel loading operations by 95 weight percent.	40 CFR 63.562(b)(4)	N/A	No
		Option to apply for a maintenance allowance for loading berths based on a percent of annual throughput of annual marine tank vessel loading operation time.	40 CFR 63.562(b)(6)	N/A	No
		Operate and maintain the source, including associated air pollution control equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.	40 CFR 63.562(e)	N/A	No
		Develop a written operation and maintenance plan that describes in detail a program of corrective action for varying air pollution control equipment and monitoring equipment used to comply with the MACT standard.	40 CFR 63.562(e)	N/A	No
		Follow vapor-tightness requirements for the marine vessels to be loaded.	40 CFR 63.563(a)(4)	N/A	No
		Requirements that specify monitoring-			
		Determine continuing compliance of the VCU control system by monitoring for outlet VOC concentration or temperature in accordance with 40 CFR § 63.564.	40 CFR 63.564	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Records of all maintenance performed on the air pollution control equipment shall be maintained.	40 CFR 63.562(b)(6)	N/A	No
		Requirements that specify performance testing-			
		Perform an initial performance test of the VCU control system according to 40 CFR § 63.563(b)(1).	40 CFR 63.563(b)(1)	N/A	N/A

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
VCU1, 2, & 3 - VCU Stacks 1, 2, & 3 (Continued)	LAC 33.III.Chapter 11	**Requirements that limit emissions or operations-**			
		Opacity <= 20 percent, except for emissions that have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.	LAC 33:III.1101.B	6 Minutes in any 60 Minute Consecutive Period	No
	LAC 33.III.Chapter 13	**Requirements that limit emissions or operations-**			
		Opacity <= 20 percent, except for emissions that have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.	LAC 33:III.1311.C	6 Minutes in any 60 Minute Consecutive Period	No

TABLE 3. EXPLANATION FOR EXEMPTION STATUS OR NON-APPLICABILITY OF A SOURCE

Emission Point ID No:	Requirement	Exempt or Does Not Apply	Explanation	Citation Providing for Exemption or Non-applicability
BMOP DWP Facility	NSPS Subpart OOOOa - Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution [40 C.F.R. Part 60 Subpart OOOOa]	Does Not Apply	The facility is an offshore platform.	40 C.F.R. § 60.5365a
	NESHAP Subpart V - National Emission Standards for Hazardous Air Pollutants for Equipment Leaks (Fugitive Emission Sources) [40 C.F.R. Part 61 Subpart V]	Does Not Apply	Project components will not operate in volatile hazardous air pollutant (VHAP) service.	40 C.F.R. § 61.240(a)
	NESHAP Subpart H - National Emission Standards for Hazardous Air Pollutants for Equipment Leaks [40 C.F.R. Part 63 Subpart H]	Does Not Apply	No Part 63 subpart that applies to the Project references Subpart H.	40 C.F.R. § 63.160(a)
	NESHAP Subpart HH - National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities [40 C.F.R. Part 63 Subpart HH]	Does Not Apply	The facility is not a production facility of oil and natural gas.	40 C.F.R. § 63.760
	NESHAP Subpart VV - National Emission Standards for Hazardous Air Pollutants for Oil-Water Separators and Organic-Water Separators [40 C.F.R. Part 63 Subpart VV]	Does Not Apply	No Part 63 subpart that applies to the Project references Subpart VV.	40 C.F.R. § 63.1040
	NESHAP Subpart EEEE - National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) [40 C.F.R. Part 63 Subpart EEEE]	Does Not Apply	The definition storage vessel specifically excludes surge control vessels. The other storage tanks proposed do not store an organic liquid as defined in the rule (excludes diesel, and fuels used for refueling). The project will not include a transfer rack, as the delivery of crude is to marine vessel, not to a cargo tank or tank car. Thus this subpart does not apply	40 C.F.R. 63.2406
	Chemical Accident Prevention Provisions [40 C.F.R. Part 68]	Does Not Apply	Facility does not produce, process, handle, or store any substance listed greater than the threshold amounts.	40 C.F.R. § 68
	Acid Rain Program General Provisions [40 C.F.R. Part 72]	Does Not Apply	The units at the facility are non-utility units, and non-utility units are not subject to the Acid Rain Program.	40 C.F.R. § 72.6(b)(8)
	Emission Standards for Sulfur Dioxide [LAC 33:III.Chapter 15]	Does Not Apply	No single point source emits or has the potential to emit 5 tons per year or more of SO_2.	LAC 33:III.1502.A.3
	Marine Vapor Recovery [LAC 33:III.Chapter 2108]	Does Not Apply	This facility is located offshore, not onshore in any of the Louisiana parishes. Therefore, this regulation does not apply.	LAC 33:III.2108
	Fugitive Emission Control [LAC 33:III.Chapter 2121]	Exempt	Facility is not one of the facility types subject to this regulation; the definition of natural gas processing plant excludes compressor stations, dehydration units, sweetening units, field treatment, underground storage facilities, liquefied natural gas units, and field gas gathering systems.	LAC 33:III.2121.A
	Chemical Accident Prevention and Minimization of Consequences [LAC 33:III.Chapter 59]	Does Not Apply	Facility does not produce, process, handle, or store any substance listed greater than the threshold amounts.	LAC 33:III.5907

TABLE 3. EXPLANATION FOR EXEMPTION STATUS OR NON-APPLICABILITY OF A SOURCE

Emission Point ID No:	Requirement	Exempt or Does Not Apply	Explanation	Citation Providing for Exemption or Non-applicability
LPFL HPFL	Emission Standards for Sulfur Dioxide [LAC 33:III.Chapter 15]	Does not apply	The units will not emit 5 tons per year or more of SO_2 to the atmosphere.	LAC 33:III.1502.A.3
NGGEN1 NGGEN2	Control of Emissions of Smoke [LAC 33:III.Chapter 11]	Exempt	The units will burn only natural gas and are exempt from the requirements of LAC 33:III.1101.	LAC 33:III.1107.B.1
	Emission Standards for Sulfur Dioxide [LAC 33:III.Chapter 15]	Does not apply	The units will not emit 5 tons per year or more of SO_2 to the atmosphere.	LAC 33:III.1502.A.3
	Control of Emissions of Nitrogen Oxides (NO_X) [LAC 33:III. Chapter 22]	Does not apply	The facility is not located in a non-attainment area or the region of influence.	LAC 33:III.2201.A
BCRANE1 BCRANE2 DGEN BFWP CFWP	Emission Standards for Sulfur Dioxide [LAC 33:III.Chapter 15]	Does Not Apply	Each unit emits less than 5 tons per year of sulfur dioxide. Shall record and retain data to show annual potential emissions from each unit.	LAC 33:III.1502.A.3 and 1513.C
	LAC 33:III Chapter 51 - Comprehensive Toxic Air Pollutant Emission Control Program [LAC 33:III.Chapter 51]	Exempt	TAP emissions are from the combustion of Group 1 virgin fossil fuels.	LAC 33:III.5105.B.3.a
PDST SRGT	NSPS Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978 [40 C.F.R. Part 63 Subpart K]	Does Not Apply	Storage Tank constructed after May 19, 1978.	40 C.F.R. § 60.110(c)(1).
	NSPS Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984 [40 C.F.R. Part 63 Subpart Ka]	Does Not Apply	Storage Tank constructed after July 23, 1984.	40 C.F.R. § 60.110a
PDST	NSPS Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 [40 C.F.R. Part 63 Subpart Kb]	Does Not Apply	The storage capacity for each of the tank is less than 75 m^3.	40 C.F.R. § 60.110b(a).
	Control of Emissions of Organic Compounds - Storage of Volatile Organic Compounds [LAC 33:III:2103]	Does Not Apply	Tank will store diesel which has a vapor pressure of lower than 1.5 psia; therefore, the requirements of LAC 33:III.2103 are not applicable.	LAC 33:III 2103.B

TABLE 3. EXPLANATION FOR EXEMPTION STATUS OR NON-APPLICABILITY OF A SOURCE

Emission Point ID No:	Requirement	Exempt or Does Not Apply	Explanation	Citation Providing for Exemption or Non-applicability
SRGT	NSPS Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 [40 C.F.R. Part 63 Subpart Kb]	Does Not Apply	The surge tank is potentially subject to NSPS Subpart Kb. However, the surge tank is considered a process tank. The definition storage vessel specifically excludes process tanks. Thus subpart Kb does not apply.	40 C.F.R. § 60.111b
	LAC 33:III Chapter 2103 - Storage of Volatile Organic Compounds	Exempt	Storage tank is used for crude oil or condensate and having a nominal storage capacity of less than 420,000 gallons and storage tank is NOT subject to New Source Performance Standards;	LAC 33:III 2103.G.1
FUG	Fugitive Emission Control [LAC 33:III.Chapter 2121]	Exempt	Facility is not one of the facility types subject to this regulation; the definition of natural gas processing plant excludes compressor stations, dehydration units, sweetening units, field treatment, underground storage facilities, liquefied natural gas units, and field gas gathering systems.	LAC 33:III.2121.A
VCU 1, 2, and 3	Compliance Assurance Monitoring [40 C.F.R. Part 64]	Does Not Apply	The requirements of 40 CFR 64 shall not apply to emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act.	40 CFR 64.2(b)(1)(i)
	Emission Standards for Sulfur Dioxide [LAC 33:III.Chapter 15]	Does Not Apply	No single point source emits or has the potential to emit 5 tons per year or more of SO_2.	LAC 33:III.1502.A.3

TABLE 4. EQUIPMENT LIST

Emission Point ID No:	Description	Construction Date	Routes to:	Operating Rate/Volume	Applicable Requirement(s)?
NGGEN1	Natural Gas Generator #1	Proposed	NGGEN CAP	17,820 scf/hr	Yes
NGGEN2	Natural Gas Generator #2	Proposed	NGGEN CAP	17,820 scf/hr	Yes
UNLD1	Uncaptured Loading at Buoy #1	Proposed	UNLD CAP	80,000 bbl/hr	No
UNLD2	Uncaptured Loading at Buoy #2	Proposed	UNLD CAP	80,000 bbl/hr	No
UNLD1	Uncaptured Loading at Buoy #1	Proposed	VCU 1, 2, or 3	80,000 bbl/hr	No
UNLD2	Uncaptured Loading at Buoy #2	Proposed	VCU 1, 2, or 3	80,000 bbl/hr	No

23. Emissions Inventory Questionnaire (EIQ) Forms [LAC 33:III.517.D.3; 517.D.6]

Complete one (1) EIQ for:

- Each emission source. If two emission sources have a common stack, the applicant may submit one EIQ sheet for the common emissions point. Note any emissions sources that route to this common point in Table 4 of the application.
- Each emissions CAP that is proposed, including each source that is part of the CAP.
- Each alternate operating scenario that a source may operate under. Some common scenarios are:
    1. Sources that combust multiple fuels
    2. Sources that have startup/shutdown max lb/hr emission rates higher than the max lb/hr for normal operating conditions would need a separate EIQ addressing the startup/shutdown emission rates
- Fugitive emissions releases. One (1) EIQ should be completed for each of the following types of fugitive emissions sources or emissions points:
    1. Equipment leaks.
    2. Non-equipment leaks (i.e., road dust, settling ponds, etc).

For each EIQ:

- Fill in all requested information.
- Speciate all Toxic Air Pollutants and Hazardous Air Pollutants emitted by the source.
- Use appropriate significant figures.
- Consult instructions.

The EIQ is in Microsoft Word Excel. Visit the following website to get to the EIQ form.
http://deq.louisiana.gov/page/air-permit-applications

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
UNLD CAP	Uncaptured Loading CAP	Method ____ Datum ____
Tempo Subject Item ID No.		UTM Zone ____ Horizontal ____ mE Vertical ____ mN
		Latitude ____ ° ____ ' ____ " ____ hundredths
		Longitude ____ ° ____ ' ____ " ____ hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	N/A ft N/A ft^2	N/A ft	N/A ft/sec	N/A ft^3/min	N/A F	8,760 hr/yr	proposed	25%	25%	25%	25%

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a		
	b		
	c		

Notes

This emissions CAP includes emissions from Uncaptured Loading Buoy 1 (UNLD1) and Uncaptured Loading Buoy 2 (UNLD2). See individual EIQs for max hourly emissions and stack information.

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	605,000,000	bbl/yr
Maximum Operating Rate/Throughput	700,800,000	bbl/yr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered			Engine Model Year	
Date Engine Was Built by Manufacturer				

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation) UNLD CAP Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Permitted Emission Rate (Current) Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Total VOC (including those listed below)				4552.92	--	1604.05	--	A		ppm by vol
Hydrogen sulfide			07783-06-4	1.98	--	0.70	--	A		ppm by vol
n-Hexane			00110-54-3	186.21	--	65.60	--	A		ppm by vol
Benzene			00071-43-2	36.44	--	12.84	--	A		ppm by vol
Toluene			00108-88-3	16 18	--	5.70	--	A		ppm by vol
Ethyl benzene			00100-41-4	2.26	--	0.80	--	A		ppm by vol
1,2,4 - Trimethylbenzene				0.49	--	0.17	--	A		ppm by vol

Emission Point ID No. (Designation) UNLD CAP Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
1,3-dimethylbenzene				2.17	–	0.76	–	A		ppm by vol
1,4-dimethylbenzene				1.51	–	0.53	–	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	9.46	–	3.33	–	A		ppm by vol
Cumene			00098-82-8	0.27	–	0.09	–	A		ppm by vol
Cresol			01319-77-3	0.03	–	0.01	–	A		ppm by vol
Naphthalene			00091-20-3	0.03	–	0.01	–	A		ppm by vol
Phenol			00108-95-2	0.07	–	0.02	–	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
UNLD1	Uncaptured Loading at Buoy #1	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499627.30 mE Vertical: 3147270.30 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	2.17 ft	36.09 ft	33.74 ft/sec	7,486.11 ft^3/min	90 F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a		
	b		
	c		

Notes

Average hourly and annual emissions permitted under Uncaptured Loading CAP.

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	80,000	bbl/hr
Maximum Operating Rate/Throughput	80,000	bbl/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered: Engine Model Year:

Date Engine Was Built by Manufacturer:

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): UNLD1	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Total VOC (including those listed below)				--	4989.04	--	--	A		ppm by vol
Hydrogen sulfide			07783-06-4	--	64.55	--	--	A		ppm by vol
n-Hexane			00110-54-3	--	204.04	--	--	A		ppm by vol
Benzene			00071-43-2	--	39.93	--	--	A		ppm by vol
Toluene			00108-88-3	--	17.73	--	--	A		ppm by vol
Ethyl benzene			00100-41-4	--	2.48	--	--	A		ppm by vol
1,2,4 - Trimethylbenzene				--	0.53	--	--	A		ppm by vol

Emission Point ID No. (Designation) UNLD1	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
1,3-dimethylbenzene				--	2.38	--	--	A		ppm by vol
1,4-dimethylbenzene				--	1.66	--	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	--	10.36	--	--	A		ppm by vol
Cumene			00098-82-8	--	0.29	--	--	A		ppm by vol
Cresol			01319-77-3	--	0.04	--	--	A		ppm by vol
Naphthalene			00091-20-3	--	0.03	--	--	A		ppm by vol
Phenol			00108-95-2	--	0.07	--	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
UNLD2	Uncaptured Loading at Buoy #2	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 501099.00 mE Vertical: 3146871.60 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	2.17 ft	36.09 ft	33.74 ft/sec	7,486.11 ft^3/min	90 F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a		
	b		
	c		

Notes

Average hourly and annual emissions permitted under Uncaptured Loading CAP.

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	80,000	bbl/hr
Maximum Operating Rate/Throughput	80,000	bbl/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered: Engine Model Year:

Date Engine Was Built by Manufacturer:

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation) UNLD2	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Total VOC (including those listed below)				--	4989.04	--	--	A		ppm by vol
Hydrogen sulfide			07783-06-4	--	64.55	--	--	A		ppm by vol
n-Hexane			00110-54-3	--	204.04	--	--	A		ppm by vol
Benzene			00071-43-2	--	39.93	--	--	A		ppm by vol
Toluene			00108-88-3	--	17.73	--	--	A		ppm by vol
Ethyl benzene			00100-41-4	--	2.48	--	--	A		ppm by vol
1,2,4 - Trimethylbenzene				--	0.53	--	--	A		ppm by vol

Emission Point ID No. (Designation) UNLD2 Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
1,3-dimethylbenzene				--	2.38	--	--	A		ppm by vol
1,4-dimethylbenzene				--	1.66	--	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	--	10.36	--	--	A		ppm by vol
Cumene			00098-82-8	--	0.29	--	--	A		ppm by vol
Cresol			01319-77-3	--	0.04	--	--	A		ppm by vol
Naphthalene			00091-20-3	--	0.03	--	--	A		ppm by vol
Phenol			00108-95-2	--	0.07	--	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
NGGEN CAP	Natural Gas Generator CAP	Method _____ Datum _____
Tempo Subject Item ID No.		UTM Zone _____ Horizontal _____ mE Vertical _____ mN
		Latitude _____ ° _____ ' _____ " _____ hundredths
		Longitude _____ ° _____ ' _____ " _____ hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	N/A ft	N/A ft	N/A ft/sec	N/A ft^3/min	N/A F	8,760 hr/yr	proposed	25%	25%	25%	25%
	N/A ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a		
	b		
	c		

Notes

This emissions CAP includes emissions from NG Generator No 1 (NGGEN1) and NG Generator No 2 (NGGEN2). See individual EIQs for max hourly emissions and stack information.

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	156.10	MMscf/yr
Maximum Operating Rate/Throughput	156 10	MMscf/yr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered _____ Engine Model Year _____

Date Engine Was Built by Manufacturer _____

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation) NGGEN CAP	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				0.18	--	0.80	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				0.18	--	0.80	--	A		gr/std ft^3
Sulfur dioxide				0.01	--	0.05	--	A		ppm by vol
Nitrogen oxides				2.57	--	11.24	--	A		ppm by vol
Carbon monoxide				1.18	--	5.17	--	A		ppm by vol
Total VOC (including those listed below)				1.44	--	6.29	--	A		ppm by vol
Sulfuric Acid			07664-93-9	<0.001	--	<0.01	--	A		ppm by vol

Emission Point ID No. (Designation) NGGEN CAP Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Acetaldehyde			00075-07-0	0.15	--	0.67	--	A		ppm by vol
Acrolein			00107-02-8	0.09	--	0.41	--	A		ppm by vol
Benzene			00071-43-2	0.01	--	0.04	--	A		ppm by vol
Biphenyl			00092-52-4	0.004	--	0.02	--	A		ppm by vol
1,3-Butadiene			00106-99-0	0.005	--	0.02	--	A		ppm by vol
Carbon tetrachloride			00056-23-5	<0.001	--	<0.01	--	A		ppm by vol
Chlorobenzene			00108-90-7	<0.001	--	<0.01	--	A		ppm by vol
Chloroform			00067-66-3	<0.001	--	<0.01	--	A		ppm by vol
1,3-Dichloropropene			00542-75-6	<0.001	--	<0.01	--	A		ppm by vol
Ethyl benzene			00100-41-4	<0.001	--	<0.01	--	A		ppm by vol
1,2-Dibromoethane			00106-93-4	<0.001	--	<0.01	--	A		ppm by vol
Formaldehyde			00050-00-0	0.61	--	2.67	--	A		ppm by vol
Methanol			00067-56-1	0.05	--	0.20	--	A		ppm by vol
Dichloromethane			00075-09-2	<0.001	--	<0.01	--	A		ppm by vol
2-Methylnaphthalene			00091-57-6	<0.001	--	<0.01	--	A		ppm by vol
n-Hexane			00110-54-3	0.02	--	0.09	--	A		ppm by vol
Naphthalene			00091-20-3	0.001	--	0.01	--	A		ppm by vol
Polynuclear Aromatic Hydrocarbons				<0.001	--	<0.01	--	A		ppm by vol
Phenanthrene				<0.001	--	<0.01	--	A		ppm by vol
Phenol			00108-95-2	<0.001	--	<0.01	--	A		ppm by vol
Styrene			00100-42-5	<0.001	--	<0.01	--	A		ppm by vol
Toluene			00108-88-3	0.01	--	0.03	--	A		ppm by vol
1,1,2,2-Tetrachloroethane			00079-34-5	<0.001	--	<0.01	--	A		ppm by vol
1,1,2-Trichloroethane			00079-00-5	<0.001	--	<0.01	--	A		ppm by vol
2,2,4-Trimethylpentane			00540-84-1	0.005	--	0.02	--	A		ppm by vol
Vinyl chloride			00075-01-4	<0.001	--	<0.01	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	0.003	--	0.01	--	A		ppm by vol
CO2e				2938.60	--	12871.09	--	A		ppm by vol

State of LouGsGana

EmGssGons Gnventory QuestGonnaGre (EGQ) for AGr Pollutants

Date of submGttal: Apr 2023

EmGssGon PoGnt GD No. (DesGgnatGon)	DescrGptGve Name of the EmGssGons Source (Alt. Name)	ApproxGmate LocatGon of Stack or Vent (see GnstructGons)
NGGEN1	Natural Gas Generator #1	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499556.10 mE Vertical: 3145223.00 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.67 ft	114.40 ft	125.98 ft/sec	2,638.61 ft^3/min	924 F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Fuel — Type of Fuel Used and Heat Input (see instructions)

	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	18.18
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	17,820	scf/hr
Maximum Operating Rate/Throughput	17,820	scf/hr
Design Capacity/Volume/Cylinder Displacement	2,328	HP
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered: Engine Model Year:

Date Engine Was Built by Manufacturer:

SI Engines: ☐ Rich Burn ☑ Lean Burn ☐ 2 Stroke ☑ 4 Stroke

EmGssGon PoGnt GD No. (DesGgnatGon) NGGEN1	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				--	0.18	--	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				--	0.18	--	--	A		gr/std ft^3
Sulfur dioxide				--	0.01	--	--	A		ppm by vol
Nitrogen oxides				--	2.57	--	--	A		ppm by vol
Carbon monoxide				--	1.18	--	--	A		ppm by vol
Total VOC (including those listed below)				--	1.44	--	--	A		ppm by vol
Sulfuric Acid			07664-93-9	--	<0.001	--	--	A		ppm by vol

EmGssGon PoGnt GD No. (DesGgnatGon) NGGEN1	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Acetaldehyde			00075-07-0	--	0.15	--	--	A		ppm by vol
Acrolein			00107-02-8	--	0.09	--	--	A		ppm by vol
Benzene			00071-43-2	--	0.01	--	--	A		ppm by vol
Biphenyl			00092-52-4	--	0.004	--	--	A		ppm by vol
1,3-Butadiene			00106-99-0	--	0.005	--	--	A		ppm by vol
Carbon tetrachloride			00056-23-5	--	<0.001	--	--	A		ppm by vol
Chlorobenzene			00108-90-7	--	<0.001	--	--	A		ppm by vol
Chloroform			00067-66-3	--	<0.001	--	--	A		ppm by vol
1,3-Dichloropropene			00542-75-6	--	<0.001	--	--	A		ppm by vol
Ethyl benzene			00100-41-4	--	<0.001	--	--	A		ppm by vol
1,2-Dibromoethane			00106-93-4	--	<0.001	--	--	A		ppm by vol
Formaldehyde			00050-00-0	--	0.61	--	--	A		ppm by vol
Methanol			00067-56-1	--	0.05	--	--	A		ppm by vol
Dichloromethane			00075-09-2	--	<0.001	--	--	A		ppm by vol
2-Methylnaphthalene			00091-57-6	--	<0.001	--	--	A		ppm by vol
n-Hexane			00110-54-3	--	0.02	--	--	A		ppm by vol
Naphthalene			00091-20-3	--	0.001	--	--	A		ppm by vol
Polynuclear Aromatic Hydrocarbons				--	<0.001	--	--	A		ppm by vol
Phenanthrene				--	<0.001	--	--	A		ppm by vol
Phenol			00108-95-2	--	<0.001	--	--	A		ppm by vol
Styrene			00100-42-5	--	<0.001	--	--	A		ppm by vol
Toluene			00108-88-3	--	0.01	--	--	A		ppm by vol
1,1,2,2-Tetrachloroethane			00079-34-5	--	<0.001	--	--	A		ppm by vol
1,1,2-Trichloroethane			00079-00-5	--	<0.001	--	--	A		ppm by vol
2,2,4-Trimethylpentane			00540-84-1	--	0.005	--	--	A		ppm by vol
Vinyl chloride			00075-01-4	--	<0.001	--	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	--	0.003	--	--	A		ppm by vol
CO2e				--	2938.60	--	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
NGGEN2	Natural Gas Generator #2	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499556.10 mE Vertical: 3145223.00 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.67 ft	114.40 ft	125.98 ft/sec	2,638.61 ft^3/min	924 F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Fuel — Type of Fuel Used and Heat Input (see instructions)

	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	18.18
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	17,820	scf/hr
Maximum Operating Rate/Throughput	17,820	scf/hr
Design Capacity/Volume/Cylinder Displacement	2,328	HP
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered: Engine Model Year:

Date Engine Was Built by Manufacturer:

SI Engines: ☐ Rich Burn ☑ Lean Burn ☐ 2 Stroke ☑ 4 Stroke

Emission Point ID No. (Designation): NGGEN2 — Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Permitted Emission Rate (Current) Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Particulate matter (PM_{10})				--	0.18	--	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				--	0.18	--	--	A		gr/std ft^3
Sulfur dioxide				--	0.01	--	--	A		ppm by vol
Nitrogen oxides				--	2.57	--	--	A		ppm by vol
Carbon monoxide				--	1.18	--	--	A		ppm by vol
Total VOC (including those listed below)				--	1.44	--	--	A		ppm by vol
Sulfuric Acid			07664-93-9	--	<0.001	--	--	A		ppm by vol

Emission Point ID No. (Designation) NGGEN2	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Acetaldehyde			00075-07-0	--	0.15	--	--	A		ppm by vol
Acrolein			00107-02-8	--	0.09	--	--	A		ppm by vol
Benzene			00071-43-2	--	0.01	--	--	A		ppm by vol
Biphenyl			00092-52-4	--	0.004	--	--	A		ppm by vol
1,3-Butadiene			00106-99-0	--	0.005	--	--	A		ppm by vol
Carbon tetrachloride			00056-23-5	--	<0.001	--	--	A		ppm by vol
Chlorobenzene			00108-90-7	--	<0.001	--	--	A		ppm by vol
Chloroform			00067-66-3	--	<0.001	--	--	A		ppm by vol
1,3-Dichloropropene			00542-75-6	--	<0.001	--	--	A		ppm by vol
Ethyl benzene			00100-41-4	--	<0.001	--	--	A		ppm by vol
1,2-Dibromoethane			00106-93-4	--	<0.001	--	--	A		ppm by vol
Formaldehyde			00050-00-0	--	0.61	--	--	A		ppm by vol
Methanol			00067-56-1	--	0.05	--	--	A		ppm by vol
Dichloromethane			00075-09-2	--	<0.001	--	--	A		ppm by vol
2-Methylnaphthalene			00091-57-6	--	<0.001	--	--	A		ppm by vol
n-Hexane			00110-54-3	--	0.02	--	--	A		ppm by vol
Naphthalene			00091-20-3	--	0.001	--	--	A		ppm by vol
Polynuclear Aromatic Hydrocarbons				--	<0.001	--	--	A		ppm by vol
Phenanthrene				--	<0.001	--	--	A		ppm by vol
Phenol			00108-95-2	--	<0.001	--	--	A		ppm by vol
Styrene			00100-42-5	--	<0.001	--	--	A		ppm by vol
Toluene			00108-88-3	--	0.01	--	--	A		ppm by vol
1,1,2,2-Tetrachloroethane			00079-34-5	--	<0.001	--	--	A		ppm by vol
1,1,2-Trichloroethane			00079-00-5	--	<0.001	--	--	A		ppm by vol
2,2,4-Trimethylpentane			00540-84-1	--	0.005	--	--	A		ppm by vol
Vinyl chloride			00075-01-4	--	<0.001	--	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	--	0.003	--	--	A		ppm by vol
CO2e				--	2938.60	--	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
DGEN	Emergency Diesel Generator	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499572.20 mE Vertical: 3145228.90 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.67 ft	104.40 ft	103.00 ft/sec	2,157.20 ft^3/min	757 F	100 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a	Diesel	3.15
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	315.00	MMBtu/yr
Maximum Operating Rate/Throughput	3.15	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement	450	hp
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered | Engine Model Year

Date Engine Was Built by Manufacturer

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): DGEN	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				0.17	0.17	0.01	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				0.17	0.17	0.01	--	A		gr/std ft^3
Sulfur dioxide				0.32	0.32	0.02	--	A		ppm by vol
Nitrogen oxides				2.96	2.96	0.15	--	A		ppm by vol
Carbon monoxide				2.59	2.59	0.13	--	A		ppm by vol
Total VOC (including those listed below)				2.96	2.96	0.15	--	A		ppm by vol

Emission Point ID No. (Designation) DGEN Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Sulfuric Acid			07664-93-9	0.01	0.01	<0.001	--	A		ppm by vol
CO2e				515.38	515.38	25.77	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
BCRANE1	Platform B Crane #1	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499539.50 mE Vertical: 3145195.80 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.33 ft	154.67 ft	97.27 ft/sec	509.28 ft^3/min	980 F	4,380 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a	Diesel	3.33
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	14,564	MMBtu/yr
Maximum Operating Rate/Throughput	3.33	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement	475	hp
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof Floating Roof ☐ External ☐ Internal

Date Engine Ordered | Engine Model Year

Date Engine Was Built by Manufacturer

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): BCRANE1	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				0.05	0.05	0.11	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				0.05	0.05	0.11	--	A		gr/std ft^3
Sulfur dioxide				0.34	0.34	0.74	--	A		ppm by vol
Nitrogen oxides				0.47	0.47	1.03	--	A		ppm by vol
Carbon monoxide				2.73	2.73	5.99	--	A		ppm by vol
Total VOC (including those listed below)				0.22	0.22	0.49	--	A		ppm by vol

Emission Point ID No. (Designation) BCRANE1 Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Sulfuric Acid			07664-93-9	0.01	0.01	0.02	--	A		ppm by vol
Acetaldehyde			00075-07-0	0.003	0.003	0.01	--	A		ppm by vol
Acrolein			00107-02-8	<0.001	<0.001	<0.01	--	A		ppm by vol
Benzene			00071-43-2	0.003	0.003	0.01	--	A		ppm by vol
Formaldehyde			00050-00-0	0.004	0.004	0.01	--	A		ppm by vol
Toluene			00108-88-3	0.001	0.001	<0.01	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	<0.001	<0.001	<0.01	--	A		ppm by vol
Polynuclear Aromatic Hydrocarbons				<0.001	<0.001	<0.01	--	A		ppm by vol
CO2e				544.01	544.01	1191.39	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
BCRANE2	Platform B Crane #2	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499573.90 mE Vertical: 3145230.20 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.33 ft	154.67 ft	97.27 ft/sec	509.28 ft^3/min	980 F	4,380 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a	Diesel	3.33
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	14,564	MMBtu/yr
Maximum Operating Rate/Throughput	3.33	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement	475	hp
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered | Engine Model Year

Date Engine Was Built by Manufacturer

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): BCRANE2	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				0.05	0.05	0.11	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				0.05	0.05	0.11	--	A		gr/std ft^3
Sulfur dioxide				0.34	0.34	0.74	--	A		ppm by vol
Nitrogen oxides				0.47	0.47	1.03	--	A		ppm by vol
Carbon monoxide				2.73	2.73	5.99	--	A		ppm by vol
Total VOC (including those listed below)				0.22	0.22	0.49	--	A		ppm by vol

Emission Point ID No. (Designation) BCRANE2 Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Sulfuric Acid			07664-93-9	0.01	0.01	0.02	--	A		ppm by vol
Acetaldehyde			00075-07-0	0.003	0.003	0.01	--	A		ppm by vol
Acrolein			00107-02-8	<0.001	<0.001	<0.01	--	A		ppm by vol
Benzene			00071-43-2	0.003	0.003	0.01	--	A		ppm by vol
Formaldehyde			00050-00-0	0.004	0.004	0.01	--	A		ppm by vol
Toluene			00108-88-3	0.001	0.001	<0.01	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	<0.001	<0.001	<0.01	--	A		ppm by vol
Polynuclear Aromatic Hydrocarbons				<0.001	<0.001	<0.01	--	A		ppm by vol
CO2e				544.01	544.01	1191.39	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
BFWP	Platform B Firewater Pump	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499552.80 mE Vertical: 3145247.80 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.33 ft ft^2	56.16 ft	133.10 ft/sec	696.91 ft^3/min	980 F	100 hr/yr	proposed	25%	25%	25%	25%

Fuel — Type of Fuel Used and Heat Input (see instructions)

	Type of Fuel	Heat Input (MMBTU/hr)
a	Diesel	4.55
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	455	MMBtu/yr
Maximum Operating Rate/Throughput	4.55	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement	650	HP
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered: Engine Model Year:

Date Engine Was Built by Manufacturer:

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): BFWP Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Permitted Emission Rate (Current): Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Particulate matter (PM_{10})				0.25	0.25	0.01	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				0.25	0.25	0.01	--	A		gr/std ft^3
Sulfur dioxide				0.46	0.46	0.02	--	A		ppm by vol
Nitrogen oxides				4.30	4.30	0 21	--	A		ppm by vol
Carbon monoxide				3.73	3.73	0 19	--	A		ppm by vol
Total VOC (including those listed below)				4.30	4 30	0 21	--	A		ppm by vol

Emission Point ID No. (Designation) BFWP Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Sulfuric Acid			07664-93-9	0.01	0.01	<0.001	–	A		ppm by vol
CO2e				744.44	744.44	37.22	–	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
CFWP	Platform C Firewater Pump	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499507.67 mE Vertical: 3145358.27 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.33 ft	56.06 ft	133.10 ft/sec	696.91 ft^3/min	980 F	100 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a	Diesel	4.55
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	455	MMBtu/yr
Maximum Operating Rate/Throughput	4.55	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement	650	HP
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered: Engine Model Year:

Date Engine Was Built by Manufacturer:

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): CFWP	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				0.25	0.25	0.01	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				0.25	0.25	0.01	--	A		gr/std ft^3
Sulfur dioxide				0.46	0.46	0.02	--	A		ppm by vol
Nitrogen oxides				4.30	4.30	0 21	--	A		ppm by vol
Carbon monoxide				3.73	3.73	0 19	--	A		ppm by vol
Total VOC (including those listed below)				4.30	4 30	0 21	--	A		ppm by vol

Emission Point ID No. (Designation) CFWP Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Sulfuric Acid			07664-93-9	0.01	0.01	<0.001	–	A		ppm by vol
CO2e				744.44	744.44	37.22	–	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
PDST	Primary Diesel Storage Tank	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499557.40 mE Vertical: 3145253.30 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.50 ft	102.40 ft	3.28 ft/sec	38.65 ft^3/min	77 F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a		
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	468,000	gal/yr
Maximum Operating Rate/Throughput	400	gal/hr
Design Capacity/Volume/Cylinder Displacement	18,000	gal
Shell Height (ft)	10.00	ft
Tank Diameter (ft)	17.76	ft

Tanks: ☑ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered			Engine Model Year	
Date Engine Was Built by Manufacturer				

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation)	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
PDST										
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Total VOC (including those listed below)				0.002	--	0.01	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	<0.001	--	<0.001	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
SRGT	Surge Tank	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499527.30 mE Vertical: 3145190.30 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.50 ft	105.06 ft	3.28 ft/sec	38.65 ft^3/min	150 F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft²										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a		
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	42,000	gal/yr
Maximum Operating Rate/Throughput	80,000	gal/hr
Design Capacity/Volume/Cylinder Displacement	42,000	gal
Shell Height (ft)	47.50	ft
Tank Diameter (ft)	12.67	ft

Tanks: ☑ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered | Engine Model Year

Date Engine Was Built by Manufacturer

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): SRGT	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Total VOC (including those listed below)				0.85	--	3.73	--	A		ppm by vol
Benzo(g,h,i)perylene				0.004	--	0.02	--	A		ppm by vol
Cyclohexane				0.005	--	0.02	--	A		ppm by vol
Ethylcyclohexane				<0.001	--	<0.01	--	A		ppm by vol

Emission Point ID No. (Designation) SRGT	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Hexanol				0.004	--	0.02	--	A		ppm by vol
Toluene diisocyanate				0.002	--	0.01	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	<0.001	--	<0.01	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
VCU1	VCU Stack 1	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499496.40 mE Vertical: 3145141.10 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	12.63 ft	136.00 ft	65.62 ft/sec	492,878.79 ft^3/min	600 F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Fuel — Type of Fuel Used and Heat Input (see instructions)

	Type of Fuel	Heat Input (MMBTU/hr)
a	VLCC Vapors, Assist Natural Gas, Pilot Natural Gas	218.09
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	218.09	MMBtu/hr
Maximum Operating Rate/Throughput	218.09	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered: Engine Model Year:

Date Engine Was Built by Manufacturer:

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): VCU1 — Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Permitted Emission Rate (Current): Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Particulate matter (PM_{10})				1.14	1.14	4.99	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				1.14	1.14	4.99	--	A		gr/std ft^3
Sulfur dioxide				40.02	40.02	4.25	--	A		ppm by vol
Nitrogen oxides				32.71	32.71	143.29	--	A		ppm by vol
Carbon monoxide				60.08	60.08	263.17	--	A		ppm by vol
Total VOC (including those listed below)				82.32	82 32	260.19	--	A		ppm by vol

Emission Point ID No. (Designation) VCU1	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Hydrogen Sulfide				1.07	1.07	0.11	--	A		ppm by vol
Hexane			00110-54-3	3.37	3.37	10.64	--	A		ppm by vol
Benzene			00071-43-2	0.66	0.66	2.08	--	A		ppm by vol
Toluene			00108-88-3	0.29	0.29	0.92	--	A		ppm by vol
Ethyl benzene			00100-41-4	0.04	0.04	0.13	--	A		ppm by vol
1,2,4-Trimethylbenzene			95-63-6	0.01	0.01	0.03	--	A		ppm by vol
1,3-dimethylbenzene			108-38-3	0.04	0.04	0.12	--	A		ppm by vol
1,4-dimethylbenzene			106-42-3	0.03	0.03	0.09	--	A		ppm by vol
Xylene			01330-20-7	0.17	0.17	0.54	--	A		ppm by vol
Cumene			00098-82-8	0.005	0.005	0.02	--	A		ppm by vol
Cresol			01319-77-3	<0.001	<0.001	<0.01	--	A		ppm by vol
Naphthalene			00091-20-3	<0.001	<0.001	<0.01	--	A		ppm by vol
Phenol			00108-95-2	0.001	0.001	<0.01	--	A		ppm by vol
CO2e				35961.28	35961.28	157510.39	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
VCU2	VCU Stack 2	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499501.90 mE Vertical: 3145136.60 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	12.63 ft	136.00 ft	65.62 ft/sec	492,878.79 ft^3/min	600 F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Fuel — Type of Fuel Used and Heat Input (see instructions)

	Type of Fuel	Heat Input (MMBTU/hr)
a	VLCC Vapors, Assist Natural Gas, Pilot Natural Gas	218.09
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	218.09	MMBtu/hr
Maximum Operating Rate/Throughput	218.09	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered			Engine Model Year	
Date Engine Was Built by Manufacturer				

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): VCU2	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				1.14	1.14	4.99	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				1.14	1.14	4.99	--	A		gr/std ft^3
Sulfur dioxide				40.02	40.02	4.25	--	A		ppm by vol
Nitrogen oxides				32.71	32.71	143.29	--	A		ppm by vol
Carbon monoxide				60.08	60.08	263.17	--	A		ppm by vol
Total VOC (including those listed below)				82.32	82 32	260.19	--	A		ppm by vol

Emission Point ID No. (Designation) VCU2	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Hydrogen Sulfide				1.07	1.07	0.11	--	A		ppm by vol
Hexane			00110-54-3	3.37	3.37	10.64	--	A		ppm by vol
Benzene			00071-43-2	0.66	0.66	2.08	--	A		ppm by vol
Toluene			00108-88-3	0.29	0.29	0.92	--	A		ppm by vol
Ethyl benzene			00100-41-4	0.04	0.04	0.13	--	A		ppm by vol
1,2,4-Trimethylbenzene			95-63-6	0.01	0.01	0.03	--	A		ppm by vol
1,3-dimethylbenzene			108-38-3	0.04	0.04	0.12	--	A		ppm by vol
1,4-dimethylbenzene			106-42-3	0.03	0.03	0.09	--	A		ppm by vol
Xylene			01330-20-7	0.17	0.17	0.54	--	A		ppm by vol
Cumene			00098-82-8	0.005	0.005	0.02	--	A		ppm by vol
Cresol			01319-77-3	<0.001	<0.001	<0.01	--	A		ppm by vol
Naphthalene			00091-20-3	<0.001	<0.001	<0.01	--	A		ppm by vol
Phenol			00108-95-2	0.001	0.001	<0.01	--	A		ppm by vol
CO2e				35961.28	35961.28	157510.39	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
VCU3	VCU Stack 3	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499507.50 mE Vertical: 3145132.10 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	12.63 ft	136.00 ft	65.62 ft/sec	492,878.79 ft^3/min	600 F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Fuel — Type of Fuel Used and Heat Input (see instructions)

	Type of Fuel	Heat Input (MMBTU/hr)
a	VLCC Vapors, Assist Natural Gas, Pilot Natural Gas	218.09
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	218.09	MMBtu/hr
Maximum Operating Rate/Throughput	218.09	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered		Engine Model Year	
Date Engine Was Built by Manufacturer			

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): VCU3	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				1.14	1.14	4.99	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				1.14	1.14	4.99	--	A		gr/std ft^3
Sulfur dioxide				40.02	40.02	4.25	--	A		ppm by vol
Nitrogen oxides				32.71	32.71	143.29	--	A		ppm by vol
Carbon monoxide				60.08	60.08	263.17	--	A		ppm by vol
Total VOC (including those listed below)				82.32	82 32	260.19	--	A		ppm by vol

Emission Point ID No. (Designation) VCU3	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Hydrogen Sulfide				1.07	1.07	0.11	--	A		ppm by vol
Hexane			00110-54-3	3.37	3.37	10.64	--	A		ppm by vol
Benzene			00071-43-2	0.66	0.66	2.08	--	A		ppm by vol
Toluene			00108-88-3	0.29	0.29	0.92	--	A		ppm by vol
Ethyl benzene			00100-41-4	0.04	0.04	0.13	--	A		ppm by vol
1,2,4-Trimethylbenzene			95-63-6	0.01	0.01	0.03	--	A		ppm by vol
1,3-dimethylbenzene			108-38-3	0.04	0.04	0.12	--	A		ppm by vol
1,4-dimethylbenzene			106-42-3	0.03	0.03	0.09	--	A		ppm by vol
Xylene			01330-20-7	0.17	0.17	0.54	--	A		ppm by vol
Cumene			00098-82-8	0.005	0.005	0.02	--	A		ppm by vol
Cresol			01319-77-3	<0.001	<0.001	<0.01	--	A		ppm by vol
Naphthalene			00091-20-3	<0.001	<0.001	<0.01	--	A		ppm by vol
Phenol			00108-95-2	0.001	0.001	<0.01	--	A		ppm by vol
CO2e				35961.28	35961.28	157510.39	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
LPFL	Low Pressure Flare - Vapor Capture	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499806.40 mE Vertical: 3145265.90 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	8.39 ft	186.00 ft	65.62 ft/sec	217,498.03 ft^3/min	1832 F	275 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Fuel — Type of Fuel Used and Heat Input (see instructions)

	Type of Fuel	Heat Input (MMBTU/hr)
a	VLCC Vapors and Pilot Natural Gas	212.38
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	212.38	MMBtu/hr
Maximum Operating Rate/Throughput	212.38	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered: Engine Model Year:

Date Engine Was Built by Manufacturer:

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): LPFL	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
NOx				29.31	29.31	4.03	--	A		ppm by vol
CO				58.51	58.51	8.05	--	A		ppm by vol
SO2				13.78	13.78	0.32	--	A		ppm by vol
VOC				384.78	384.78	52.91	--	A		ppm by vol
Hexane			00110-54-3	15.74	15.74	2.16	--	A		ppm by vol
Benzene			00071-43-2	3.08	3.08	0.42	--	A		ppm by vol
Toluene			00108-88-3	1.37	1.37	0.19	--	A		ppm by vol

Emission Point ID No. (Designation) LPFL Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Ethyl benzene			00100-41-4	0.19	0.19	0.03	--	A		ppm by vol
1,2,4-Trimethylbenzene			95-63-6	0.04	0.04	0.01	--	A		ppm by vol
1,3-Dimethylbenzene			108-38-3	0.18	0.18	0.03	--	A		ppm by vol
1,4-Dimethylbenzene			106-42-3	0.13	0.13	0.02	--	A		ppm by vol
1,2-Dimethylbenzene			95-47-6	0.80	0.80	0.11	--	A		ppm by vol
Cumene			00098-82-8	0.02	0.02	<0.01	--	A		ppm by vol
CO2e				35019.51	35019.51	4815.18	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
HPFL	High Pressure Flare - Natural Gas	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499806.4 mE Vertical: 3145265.9 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	21.22 ft	186.00 ft	65.62 ft/sec	1,392,783.00 ft^3/min	1,832 F	11 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Fuel — Type of Fuel Used and Heat Input (see instructions)

	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	1,360
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	1,360	MMBtu/hr
Maximum Operating Rate/Throughput	1,360	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered: Engine Model Year:

Date Engine Was Built by Manufacturer:

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): HPFL	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
NOx				187.68	187.68	1.03	--	A		gr/std ft^3
CO				374.68	374.68	2.06	--	A		ppm by vol
SO2				0.23	0.23	<0.01	--	A		ppm by vol
VOC				24.85	24.85	0.14	--	A		ppm by vol
Hexane			00110-54-3	2.43	2.43	0.01	--	A		ppm by vol
CO2e				161048.37	161048.37	885.77	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FUG	Facility Wide Fugitives	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499554.70 mE Vertical: 3145251.00 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	N/A ft ft^2	N/A ft	N/A ft/sec	ft^3/min	N/A F	8760 hr/yr	proposed	25%	25%	25%	25%

Fuel — Type of Fuel Used and Heat Input (see instructions)

	Type of Fuel	Heat Input (MMBTU/hr)
a		
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput		
Maximum Operating Rate/Throughput		
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered _____ Engine Model Year _____

Date Engine Was Built by Manufacturer _____

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): FUG Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Permitted Emission Rate (Current): Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Total VOC (including those listed below)				5.41	5.41	23.69	--	A		ppm by vol
Hydrogen Sulfide			07783-06-4	0.001	0.001	0.01	--	A		ppm by vol
CO2e				276.45	276.45	1210.83	--	A		ppm by vol

24. NSR Applicability Summary [LAC 33:III.504 and LAC 33:III.509] ☐ N/A

Refer to Sections 4 the Prevention of Significant Deterioration Air Construction Permit Application Volume 1 for the NSR Applicability Summary.

This section consists of seven subsections, A-G, and is applicable only to new and existing major stationary sources (as defined in LAC 33:III.504 or in LAC 33:III.509) proposing to permit a physical change or change in the method of operation. It would also apply to existing minor stationary sources proposing a physical change or change in the method of operation where the change would be a major source in and of itself. Add rows to each table as necessary. Provide a written explanation of the information summarized in these tables. Consult instructions.

24.A. Project Summary

		A	B	C	D	E	F
Emission Point ID	**Description**	**New, Modified, Affected, or Unaffected***	**Pre-Project Allowables (TPY)**	**Baseline Actual Emissions (over 24-month period)**	**Projected Actual Emissions (TPY)**	**Post-Project Potential to Emit (TPY)**	**Change**
$PM_{2.5}$	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	--	--
	VCU Stack #1	NEW	N/A	N/A	N/A	4.99	4.99
	VCU Stack #2	NEW	N/A	N/A	N/A	4.99	4.99
	VCU Stack #3	NEW	N/A	N/A	N/A	4.99	4.99
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	--	--
	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	--	--
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	0.80	0.80
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	8.61E-03	8.61E-03
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	0.21	0.21
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	0.01	0.01
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	0.01	0.01

	Primary Diesel Tank	NEW	N/A	N/A	N/A	--	--
	Surge Tank	NEW	N/A	N/A	N/A	--	--
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	--	--
						16.00	**16.00**
						$PM_{2.5}$ Change:	**16.00**

PM_{10}	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	--	--
	VCU Stack #1	NEW	N/A	N/A	N/A	4.99	4.99
	VCU Stack #2	NEW	N/A	N/A	N/A	4.99	4.99
	VCU Stack #3	NEW	N/A	N/A	N/A	4.99	4.99
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	--	--
	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	--	--
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	0.80	0.80
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	8.61E-03	8.61E-03
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	0.21	0.21
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	0.01	0.01
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	0.01	0.01
	Primary Diesel Tank	NEW	N/A	N/A	N/A	--	--
	Surge Tank	NEW	N/A	N/A	N/A	--	--
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	--	--
						16.00	**16.00**
						PM_{10} Change:	**16.00**

SO_2	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	--	--
	VCU Stack #1	NEW	N/A	N/A	N/A	4.25	4.25
	VCU Stack #2	NEW	N/A	N/A	N/A	4.25	4.25
	VCU Stack #3	NEW	N/A	N/A	N/A	4.25	4.25
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	0.32	0.32
	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	1.24E-03	1.24E-03
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	0.05	0.05
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	0.02	0.02
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	1.48	1.48
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	0.02	0.02
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	0.02	0.02
	Primary Diesel Tank	NEW	N/A	N/A	N/A	--	--
	Surge Tank	NEW	N/A	N/A	N/A	--	--
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	--	--
						14.66	**14.66**
						SO_2 Change:	**14.66**

NO_X	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	--	--
	VCU Stack #1	NEW	N/A	N/A	N/A	143.29	143.29
	VCU Stack #2	NEW	N/A	N/A	N/A	143.29	143.29

	VCU Stack #3	NEW	N/A	N/A	N/A	143.29	143.29
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	4.03	4.03
	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	1.03	1.03
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	11.24	11.24
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	0.15	0.15
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	2.05	2.05
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	0.21	0.21
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	0.21	0.21
	Primary Diesel Tank	NEW	N/A	N/A	N/A	--	--
	Surge Tank	NEW	N/A	N/A	N/A	--	--
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	--	--
						448.79	**448.79**
						NO_X Change:	**448.79**

CO	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	--	--
	VCU Stack #1	NEW	N/A	N/A	N/A	263.17	263.17
	VCU Stack #2	NEW	N/A	N/A	N/A	263.17	263.17
	VCU Stack #3	NEW	N/A	N/A	N/A	263.17	263.17
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	8.05	8.05

	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	2.06	2.06
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	5.17	5.17
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	0.13	0.13
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	11.97	11.97
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	0.19	0.19
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	0.19	0.19
	Primary Diesel Tank	NEW	N/A	N/A	N/A	--	--
	Surge Tank	NEW	N/A	N/A	N/A	--	--
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	--	--
						817.25	**817.25**
						CO Change:	**817.25**

VOC	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	1,604.05	1,604.05
	VCU Stack #1	NEW	N/A	N/A	N/A	260.19	260.19
	VCU Stack #2	NEW	N/A	N/A	N/A	260.19	260.19
	VCU Stack #3	NEW	N/A	N/A	N/A	260.19	260.19
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	52.91	52.91

	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	0.14	0.14
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	6.29	6.29
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	0.15	0.15
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	0.97	0.97
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	0.21	0.21
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	0.21	0.21
	Primary Diesel Tank	NEW	N/A	N/A	N/A	8.51E-03	8.51E-03
	Surge Tank	NEW	N/A	N/A	N/A	3.73	3.73
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	23.69	23.69
						2,472.97	**2,472.97**
						VOC Change:	**2,472.97**

CO_2e	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	--	--
	VCU Stack #1	NEW	N/A	N/A	N/A	157,510	157,510
	VCU Stack #2	NEW	N/A	N/A	N/A	157,510	157,510
	VCU Stack #3	NEW	N/A	N/A	N/A	157,510	157,510
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	4,815	4,815

	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	886	886
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	12,871	12,871
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	25.77	25.77
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	2,383	2,383
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	37.22	37.22
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	37.22	37.22
	Primary Diesel Tank	NEW	N/A	N/A	N/A	--	--
	Surge Tank	NEW	N/A	N/A	N/A	--	--
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	1,211	1,211
						494,797	**494,797**
						CO_2e Change:	**494,797**

* Unaffected emissions units are not required to be listed individually. By choosing not to list unaffected emissions units, the applicant asserts that all emissions units not listed in Table 24.A will not be modified or experience an increase in actual annual emissions as part of the proposed project.

24.B. Creditable Contemporaneous Changes

Contemporaneous Period: MM/DD/YYYY – MM/DD/YYYY	

		A	B	C	D	E	F
Emission Point ID	**Description**	**Date of Modification**	**Pre-Project Allowables (TPY)**	**Baseline Actual Emissions (over 24-month period)**	**24-Month Period**	**Post-Project Potential to Emit (TPY)**	**Change**
$PM_{2.5}$							

24.B. Creditable Contemporaneous Changes

						$PM_{2.5}$ Change:	
PM_{10}							
						PM_{10} Change:	
SO_2							
						SO_2 Change:	
NO_X							
						NO_X Change:	
CO							
						CO Change:	
VOC							
						VOC Change:	
CO_2e							

24.B. Creditable Contemporaneous Changes

						CO_2e Change:	

For each source identified as "New" or "Modified" in Section 24.A, complete the following table for each pollutant that will trigger NSR. If LAER is not required per LAC 33:III.504.D.3, indicate such.

24.C. BACT/LAER Summary

Refer to Section 5 of the Prevention of Significant Deterioration Air Construction Permit Application Volume 1 for the BACT analysis.

Emission Point ID	Pollutant	BACT/LAER	Limitation	Averaging Period	Description of Control Technology/Work Practice Standard(s)

24.D. PSD Air Quality Analyses Summary – Refer to the PSD Air Construction Permit Application Volume 2

		A	B	C	D	E	F	G	H	I
Pollutant	Averaging Period	Preliminary Screening Concentration ($\mu g/m^3$)	Level of Significant Impact ($\mu g/m^3$)	Significant Monitoring Concentration ($\mu g/m^3$)	Background ($\mu g/m^3$)	Maximum Modeled Concentration ($\mu g/m^3$)	Modeled + Background Concentration ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	Modeled PSD Increment Consumption ($\mu g/m^3$)	Allowable Class II PSD Increment ($\mu g/m^3$)
$PM_{2.5}$	24-hour		-	-				35		9
	Annual		-	-				12		4
PM_{10}	24-hour		5	10				150		30
	Annual		1	-				-		17
SO_2	1-hour		7.8	-				195		-
	3-hour		25	-				1300		512
	24-hour		5	13				365		91
	Annual		1	-				80		20
NOx	1-hour		7.5	-				189		-
	Annual		1	14				100		25
CO	1-hour		2000	-				40,000	-	-
	8-hour		500	575				10,000	-	-
Lead	3-month		-	0.1				1.5	-	-

24.E Nonattainment New Source Review Offsets [LAC 33:III.517.D.16, LAC 33:III.504.D.4 & 5] ☒ **N/A**

Complete this section only if the proposed project triggers Nonattainment New Source Review (NNSR).

This project triggers NNSR review for: ☐ **NO_X** ☐ **VOC** ☐ **SO_2**

NO_X:

Is the applicant proposing to use internal offsets? ☐ **Yes** ☐ **No**

If not, identify the source of the offsets. **Company:** _____

Facility/Unit: _____

Permit No.: _____

Is an ERC Bank Application included with this application, or has an application already been submitted to LDEQ?

☐ **Yes** ☐ **No**

If the ERC application has already been submitted, give the date: _____

Identify the emissions units from which the offsets will be obtained (reference specific Emission Point ID numbers).

VOC:

Is the applicant proposing to use internal offsets? ☐ **Yes** ☐ **No**

If not, identify the source of the offsets. **Company:** _____

Facility/Unit: _____

Permit No.: _____

Is an ERC Bank Application included with this application, or has an application already been submitted to LDEQ?

☐ **Yes** ☐ **No**

If the ERC application has already been submitted, give the date: _____

Identify the emissions units from which the offsets will be obtained (reference specific Emission Point ID numbers).

SO_2:

Is the applicant proposing to use internal offsets? ☐ **Yes** ☐ **No**

If not, identify the source of the offsets. **Company:** _____

Facility/Unit: _____

Permit No.: _____

Is an ERC Bank Application included with this application, or has an application already been submitted to LDEQ?

☐ **Yes** ☐ **No**

If the ERC application has already been submitted, give the date: _____

Identify the emissions units from which the offsets will be obtained (reference specific Emission Point ID numbers).

In order to expedite processing, please be sure the ERC Bank Application is completed properly. In the case of NO_X, the document should clearly differentiate between ozone season and non-ozone season actual emissions during the baseline period. Be sure to indicate if a portion of the reductions are no longer surplus (e.g., due to new or revised federal or state regulations, use in a netting analysis, etc.).

24.F. Economic Impact

Answer the following questions.

How many temporary jobs will be added as a result of this project? 1393

How many permanent jobs will be added as a result of this project? 140

24.G Notification of Federal Land Manager [LAC 33:III.504.E.1, LAC 33:III.509.P.1]
Complete this section only if the proposed project triggers NNSR or PSD.

a. Is the proposed facility or modification located within 100 kilometers of a Class I Area? ☐ **Yes** ☒ **No**
If Yes, determination of Q/d is not required; skip to the next question. If No, complete the Q/d equation below:

$$Q/d = \frac{PM_{10\,(NEI)} + SO_{2\,(NEI)} + NO_{X\,(NEI)} + H_2SO_{4\,(NEI)}}{\text{Class I km}}$$

where:

$PM_{10\,(NEI)}$	=	net emissions increase of PM_{10}[1,2]
$SO_{2\,(NEI)}$	=	net emissions increase of SO_2[1,2]
$NO_{X\,(NEI)}$	=	net emissions increase of NO_X[1,2]
$H_2SO_{4\,(NEI)}$	=	net emissions increase of H_2SO_4[1,2]
Class I km	=	distance to nearest Class I Area[3]

$$Q/d = \frac{_____ + _____ + _____ + _____}{_____} = _____$$

Per Federal Land Manager guidance, Q values should reflect annual emissions (in tons per year, based on 24-hour maximum allowable emissions). If Q/d < 10, proceed to Section 25. If Q/d ≥ 10, complete the remainder of this Section.

b. Has the applicant provided a copy of the application to the Federal Land Manager? ☐ **Yes** ☒ **No**

c. Does the application contain modeling that demonstrates no adverse impact on Air Quality Related Values (AQRVs) in the Class I Area? ☐ **Yes** ☒ **No**

d. If Yes, indicate the model used: ☐ **VISCREEN** ☐ **PLUVUE II** ☐ **CALPUFF** ☐ **Other:**[4] _____

e. Has the Federal Land Manager concurred that the proposed project will not adversely impact any AQRVs?
☐ **Yes** ☒ **No** If Yes, please attach correspondence.

[1]If the net emissions increase of any pollutant is negative, enter "0."
[2]If the project did not trigger a netting analysis, use the project increase. In this case, the value will be less than the pollutant's significance level.
[3]In kilometers.
[4]Model must be approved by LDEQ and the Federal Land Manager.

25. Environmental Assessment Statement (EAS or "IT" Question Responses)

[La. R.S. 30:2018] ☒ **Yes** ☐ **No**

*** This section is required when applying for new Part 70 operating permits and/or major modifications. Any applications for these permit types that do not include answers to these questions will not be considered to be administratively complete. ***

For new Part 70 operating permits and/or major modifications, answers to these questions must be provided by the applicant to the local governmental authority and the designated public library at no additional costs to these entities. Consult instructions to determine what is considered to be a "local governmental authority" and a "designated public library." Indicate the name and address of the local governmental authority and the designated public library to which the answers to these questions were sent:

Name of Local Governing Authority			**Name of Designated Public Library**		
Street or P.O. Box			**Street or P.O. Box**		
City	**State**	**ZIP**	**City**	**State**	**ZIP**

Answer the following five questions on separate pages using full and complete answers. Include as many pages as necessary in order to provide full and complete answers. This information is required per Louisiana Revised Statutes 30:2018 (La. R.S. 30:2018).

Question 1: **Have the potential and real adverse environmental effects of the proposed facility been avoided to the maximum extent possible?**

Yes, Blue Marlin Offshore Port, LLC (BMOP) will avoid adverse environmental effects to the maximum extent possible as described below. Further information regarding the prevention and minimization of adverse impacts to the environment from the Project may be found in the environmental analysis being conducted concurrently on behalf of the Maritime Administration and U.S. Coast Guard (Docket number MARAD-2020-0127). EPA is serving as a cooperating agency to that environmental review process.

- **Environmental Effects to Air** – As described in the Title V Application for this facility, all new source emissions of air pollutants will be in compliance with applicable Federal and State regulations. A detailed Best Available Control Technology (BACT) analysis has been conducted, and control technologies will be implemented for Facility operation. Details (including Potential to Emit [PTE] calculations, Prevention of Significant Deterioration [PSD] analysis, and air dispersion modeling) for air emission sources can be found within this application.

- **Environmental Effects to Water** - During operation, the onshore pipeline facilities will be operated and maintained in accordance with PHMSA regulations provided in 49 CFR Part 195. BMOP will control operations from a remote location. The onshore pipeline will be monitored by a control center 24 hours per day, 7 days per week for pipeline flowrates, pressures, and operating conditions. A change in operating conditions, or in the event of an emergency, immediate communication will be made with the control center for response. The pipeline will also be monitored via aerial patrol, in accordance with 49 CFR Part 195.

BMOP will conduct maintenance pigging of the onshore pipelines on a monthly basis and will conduct inspections using smart pigs once every 5 years. Maintenance requirements and frequency of inspection for internal and external corrosion, among other factors, will be included in the Port Operation Manual.

BMOP's existing Spill Response Plan will be modified for operations in accordance with the Oil Pollution Act of 1990 and PHMSA's implementing regulations in 49 CFR Part 194, the National Oil and Hazardous Substances Pollution Contingency Plan, applicable Area Contingency Plans, the USEPA Region 6 Regional Integrated Contingency Plan, and

the One Gulf Plan. The plan has been developed to assist personnel with quickly, safely, and effectively responding to a crude oil spill either onshore or offshore and will be prepared during construction of the proposed Project.

- **Environmental Effects of Solid Waste and Hazardous Material Storage and Handling** - All facilities for the proposed BMOP Project will be designed, constructed, tested, operated, and maintained in accordance with the U.S. Department of Transportation (USDOT) regulations in 49 Code of Federal Regulations (CFR) 195 (Transportation of Hazardous Liquids by Pipeline) and all other applicable federal and state regulations.

Mainline Valves (MLVs) are designed to divide a pipeline into segments for safety reasons, including shutting down product flow and allowing access to the pipeline from the surface. MLVs will be installed on the 42-inch onshore pipeline and the Mainline. These valves will be used for isolation and spill control purposes and will be considered Emergency Flow Restricting Device (EFRD) valves.

MLVs will be installed in locations along the pipeline system that are accessible to authorized employees and that are protected from damage and tampering in accordance with USDOT standards described in 49 CFR Part 195. The MLVs will also be installed in locations along the pipeline system that will minimize damage or pollution from accidental hazardous liquid discharges in accordance USDOT standards. The MLVs will be located in fenced sites and will have electric motor operators installed for operation either locally or remotely.

- **Environmental Effects to Natural Resources** - Routine vegetation management will occur over the full width of the 50-foot-wide permanent Right-of-way (ROW) of the onshore pipelines on an annual basis (PHMSA, 2019). A smaller corridor centered on the pipeline may be cleared as necessary to maintain an herbaceous cover to facilitate corrosion and leak surveys. At waterbody crossings, BMOP will allow a 25-foot-wide riparian buffer to naturally revegetate across the full width of the ROW and will clear a small corridor centered on the pipeline only as necessary to conduct corrosion and leak surveys. In wetlands, routine vegetation management will be conducted in the same manner as in uplands; however, vegetation management of inundated or excessively saturated wetlands will be avoided. Trees will be cleared throughout the permanent ROW.

Question 2: **Does a cost benefit analysis of the environmental impact costs balanced against the social and economic benefits of the proposed facility demonstrate that the latter outweighs the former?**

The proposed project was determined to be necessary to provide the United States (U.S.) essential crude oil transportation and loading services for crude oil produced in the continental U.S. The proposed Project will enhance the country's global competitiveness, operational efficiency, and long-term economic viability.

Significant impacts to the environment are not expected due to the proposed Project. Additionally, as the part of the proposed project PSD permit application, BMOP has evaluated and proposed BACT (40 CFR 52 and LAC 33:III.509.J) limits for applicable emission units; thereby, further reducing any impacts to the environment.

Question 3: **Are there alternative projects which would offer more protection to the environment than the proposed facility without unduly curtailing non-environmental benefits?**

There are no viable alternative projects identified that would offer more environmental protection. With the appropriate BACT implemented, this facility and project will be protective of the environment.

Question 4: **Are there alternative sites which would offer more protection to the environment than the proposed facility site without unduly curtailing non-environmental benefits?**

The DWP will be located approximately eighty two (82) statute miles from the nearest point on the Louisiana coastline (99 statute miles of offshore pipe). This location was specifically chosen to meet the purpose of the project and have the capability to fully load Very Large Crude Carriers (VLCCs) with minimal total impacts, as both the offshore pipeline and the offshore facility at WC 509 are existing. There are no identified alternative sites which would offer more protection to the environment.

Question 5: **Are there mitigating measures which would offer more protection to the environment than the facility as proposed without unduly curtailing non-environmental benefits?**

For the proposed Project, BACT controls will be implemented. The BACT control level cannot be less stringent than the controls required under any applicable federal New Source Performance Standard (NSPS) or National Emission Standard for Hazardous Air Pollutants (NESHAP). Furthermore, BMOP has completed a detailed evaluation of additional control technologies, and have selected the top performing feasible control as BACT. No other feasible control options offer more protection to the environment.

PART 70 OPERATING PERMIT APPLICATION COMPLETENESS CHECKLIST

Instructions: Complete this checklist and submit with the completed air permit application.

LAC 33:III.	Completeness Questions Relative to the Part 70 Permit Application	Yes	No	NA	Location Within the Permit Application
517.A Timely Submittal	Was a Copy of the Application Also Submitted to EPA?	X			
517.B.1,2 Certification	Does the Application include a Certification by a Responsible Official?	X			AAE – Section 10
517.B.3 Certification	Does the Application Include Certification by a Professional Engineer or their Designee:	X			AAE – Section 10
517.D.1 Identifying Information	Does the Application Include:				
	1. Company Name, Physical and Mailing Address of Facility?	X			AAE – Section 1, 2
	2. Map showing Location of the Facility?	X			Appendix A
	3. Owner and Operator Names and Agent?	X			AAE – Section 1
	4. Name and Telephone Number of Plant Manager or Contact?	X			AAE – Section 11
517.D.2 SIC Codes, Source Categories	Does the Application Include a Description of the Source's Processes and Products?	X			Introduction
	Does the Application Include the Source's SIC Code?	X			AAE – Section 5
	Does the Application Include EPA Source Category of HAPs if applicable?	X			AAE – Section 22
517.D.3,6 EIQ Sheets	Has an EIQ Sheet been Completed for each Emission Point whether an Area or Point Source?	X			AAE – Section 23
517.D.4 Monitoring Devices	Does the Application Include Identification and Description of Compliance Monitoring Devices or Activities?	X			AAE – Section 22
517.D.5 Revisions and Modifications Only	For Revisions or Modifications, Does the Application include a Description of the Proposed Change and any Resulting Change in Emissions?			X	
517.D.7 General Information	Does the Application Include Information Regarding Fuels, Fuel Use, Raw Materials, Production Rates, and Operating Schedules as necessary to substantiate emission rates?	X			AAE Section 23 & Appendix B
517 D.8 Operating Limitations	Has Information Regarding any Limitations on Source Operation or any Applicable Work Practice Standards been Identified?	X			AAE Section 23
517.D.9 Calculations	Are Emission Calculations Provided?	X			Appendix B
517.D.10 Regulatory Review	Does the Application Include a Citation and Description of Applicable Louisiana and Federal Air Quality Requirements and Standards?	X			AAE – Section 22

LAC 33:III.	Completeness Questions Relative to the Part 70 Permit Application	Yes	No	NA	Location Within the Permit Application
517.D.11 Test Methods	Has a Description of or a Reference to Applicable Test Methods Used to Determine Compliance with Standards been Provided?			X	
517.D.12 Major Sources of TAPs	Does the Application include Information Regarding the Compliance History of Sources Owned or Operated by the Applicant (per LAC 33.III.5111)?			X	
517.D.13 Major Sources of TAPs	Does the Application include a Demonstration to show that the Source Meets all Applicable MACT and Ambient Air Standard Requirements?	X			See PSD Air Construction Permit Application Volume 2
517.D.14 PSD Sources Only	If Required by DEQ, Does the Application Include Information Regarding the Ambient Air Impact for Criteria Pollutants as Required for the Source Impact Analysis per LAC 33:III.509.K, L, and M?	X			See PSD Air Construction Permit Application Volume 2
517 D.15 PSD Sources Only	If Required by DEQ, Does the Application Include a Detailed Ambient Air Analysis?	X			See PSD Air Construction Permit Application Volume 2
517.D.16, 18	Has any Additional Information been Provided?	X			Introduction
517.D.17 Fees	Has the Fee Code been Identified?	X			AAE – Section 5
	Is the Applicable Fee Included with the Application?	X			See Cover Letter
517.E.1 Additional Part 70 Requirements	Does the Certification Statement Include a Description of the Compliance Status of Each Emission Point in the Source with All Applicable Requirements?	X			AAE – Section 10
517E.2 Additional Part 70 Requirements	Does the Certification Statement Include a Statement that the Source will continue to Comply with All Applicable Requirements with which the Source is in Compliance?	X			AAE – Section 10
517.E.3 Additional Part 70 Requirements	Does the Certification Statement Include a Statement that the Source will, on a timely basis, meet All Applicable Requirements that will Become Effective During the Permit Term?	X			AAE – Section 10
517.E.4 Additional Part 70 Requirements	Are there Applicable Requirements for which the Source is not in Compliance at the Time of Submittal?		X		
	Does the Application include a Compliance Plan Schedule?			X	
	Does the Schedule Include Milestone Dates for which Significant Actions will occur?			X	
	Does the Schedule Include Submittal Dates for Certified Progress Reports?			X	

LAC 33:III.	Completeness Questions Relative to the Part 70 Permit Application	Yes	No	NA	Location Within the Permit Application
517.E.5 Additional Part 70 Requirements Acid Rain	Is this Source Covered by the Federal Acid Rain Program?		X		
	Are the Requirements of LAC 33.III.517.E 1-4 included in the Acid Rain Portion of the Compliance Plan?			X	
517.E.6 Additional Part 70 Requirements	Have any Exemptions from any Applicable Requirements been Requested?	X			AAE – Section 22
	Is the List and explanations Provided?	X			AAE – Section 22
517.E.7 Additional Part 70 Requirements	Does the Application Include a Request for a Permit Shield?	X			See Section 1 of the Title V Air Operating Permit Application for the Permit Shield Request
	Does the Request List those Federally Applicable Requirements for which the Shield is Requested along with the Corresponding Draft Permit Terms and conditions which are Proposed to Maintain Compliance?	X			See Section 1 of the Title V Air Operating Permit Application for the Permit Shield Request
517.E.8 Additional Part 70 Requirements	Does the Application Identify and Reasonably Anticipated Alternative Operating Scenarios?			X	
	Does the Application include Sufficient Information to Develop permit Terms and Conditions for Each Scenario, Including Source Process and Emissions Data?			X	
517.F Confidentiality	Does the Application Include a Request for Non-Disclosure (Confidentiality)?	X			AAE – Section 3
525.B. Minor Permit Modifications	Does the Application Include a Listing of New Requirements Resulting for the Change?			X	
	Does the Application Include Certification by the Responsible Official that the Proposed Action Fits the Definition of a Minor Modification as per LAC 33:III.525.A.			X	
	Does the Certification also Request that Minor Modification Procedures be Used?			X	
	Does the Application, for Part 70 Sources, Include the Owner's Suggested Draft Permit and Completed Forms for the Permitting Authority to Use to Notify Affected States?			X	

LAC 33:III.	Completeness Questions Relative to the Part 70 Permit Application	Yes	No	NA	Location Within the Permit Application
La. R.S. 30:2018 – PSD/NNSR only	Has a copy of the answers to the questions posed in the Environmental Assessment Statement (Section 25) been sent to the local governing authority at no cost to the local governing authority?	X			
	Has a copy of the answers to the questions posed in the Environmental Assessment Statement (Section 25) been sent to the designated public library at no cost to the designated public library?	X			

APPENDIX C. DETAILED EMISSIONS CALCULATIONS

Normal Operations Emission Calculations

Stationary Summary

	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	PM Filterable (tpy)	PM_{10}[1] (tpy)	$PM_{2.5}$[1] (tpy)	H_2S (tpy)	H_2SO_4 (tpy)	Total VOC HAPs (tpy)	CO_2e (tpy)
Marine Loading											
Crude Oil Loading	--	--	1,604	--	--	--	--	0.70	--	89.9	--
Vapor Capture - VCU Stack #1	143	263	260	4.25	1.25	4.99	4.99	0.11	--	14.6	157,510
Vapor Capture - VCU Stack #2	143	263	260	4.25	1.25	4.99	4.99	0.11	--	14.6	157,510
Vapor Capture - VCU Stack #3	143	263	260	4.25	1.25	4.99	4.99	0.11	--	14.6	157,510
Vapor Capture - Low Pressure Flare	4.03	8.05	52.9	0.32	--	--	--	--	--	2.96	4,815
Supporting Platform Operations											
Natural Gas - High Pressure Flare	1.03	2.06	0.14	1.24E-03	--	--	--	--	--	0.013	886
Power Generation - Natural Gas Engines (x2)	11.2	5.17	6.29	0.05	6.14E-03	0.80	0.80	--	2.34E-03	4.22	12,871
Emergency Diesel Generator	0.15	0.13	0.15	0.02	7.40E-03	8.61E-03	8.61E-03	--	5.00E-04	6.10E-04	25.8
Platform B Cranes (x2)	2.05	11.97	0.97	1.48	0.10	0.21	0.21	--	0.05	0.06	2,383
Platform B Firewater Pump Engine	0.21	0.19	0.21	0.02	0.01	0.01	0.01	--	7.22E-04	3.58E-04	37.2
Platform C Firewater Pump Engine	0.21	0.19	0.21	0.02	0.01	0.01	0.01	--	7.22E-04	3.58E-04	37.2
Aviation Fuel Tank	--	--	5.12E-04	--	--	--	--	--	--	7.65E-05	--
Platform B Cranes Diesel Tank #1	--	--	1.93E-03	--	--	--	--	--	--	2.65E-04	--
Platform B Cranes Diesel Tank #2	--	--	1.93E-03	--	--	--	--	--	--	2.65E-04	--
Primary Diesel Tank	--	--	8.51E-03	--	--	--	--	--	--	1.17E-03	--
Surge Tank #1	--	--	3.73	--	--	--	--	--	--	0.07	--
Piping Components	--	--	23.7	--	--	--	--	5.09E-03	--	2.96	1,211
Total	**449**	**817**	**2,473**	**14.66**	**3.88**	**16.0**	**16.0**	**1.04**	**0.05**	**144**	**494,797**

[1] PM_{10} and $PM_{2.5}$ emissions are represented as the sum of filterable PM_{10}/$PM_{2.5}$ and condensable emissions.

Operations Emission Calculations
BMOP - Loading Operations

Maximum Hourly Loading Rate [1]	=	80,000	bbl/hr	
	=	3,360	1,000 gal/hr	
Maximum Annual Loading Rate [1]	=	605,000,000	bbl/yr	
	=	25,410,000	1,000 gal/yr	
Vapor Capture System Collection Efficiency [5]	=	99	%	
Vapor Capture System Maintenance Alllowance [5]	=	629	hrs/yr offline while loading	
Crude Oil Loading Specifications		Maximum	Annual	
TOC Arrival Emission Factor [1]	=	0.86	0.86	
VOC Arrival Emission Factor [2]	=	0.731	0.731	
Loading Temperature [1]	=	550	532	°R
Vapor Molecular Weight [1]	=	50	50	lb/lbmol
Crude Oil Liquid Molecular Weight [1]	=	207	207	lb/lbmol
True Vapor Pressure [1]	=	10.99	9.00	psia
Liquid H_2S Partition [3]	=	25	21	
H2S Molecular Weight	=	34.1	34.1	lb/lbmol

Criteria Pollutants

Pollutant	Emission Factor Basis		Hourly Emission Factor		Annual Emission Factor		Max Hourly Loading Vapors	Avg Hourly Loading Vapors	Annual Loading Vapors	Uncaptured Loading Emissions
			Value	Units	Value	Units	lb/hr	lb/hr	tpy	tpy
VOC	AP-42	[2]	1.48	lb/1,000 gal	1.36	lb/1,000 gal	4,989	4,553	17,216	1,604
H_2S	Site Specific	[3], [4]	125	ppmw	5	ppmw	64.55	1.98	7.48	0.70

[1] Based on current project design specifications, provided by BMOP. Molecular weight referenced from AP-42, Chapter 7, Table 7.1-2.
[2] Per AP-42, Table 5.2-3 for crude oil loading into ships (uncleaned). Total loading loss based on AP-42, Section 5.2 Equations 2 and 3 (06/08).
[3] Mass balance based and liquid H_2S partition factors from the Petroleum Processing Handbook, McGraw-Hill, New York, Figure 12-71, page 12-93. Short-term H2S concentration from Nederland permit basis.
[4] Annual mass H2S emissions calculated from a conservative assumption of 5 ppmw. The average of all samples from Nederland (>3000 samples) is 1.31 ppmw.
[5] Expected vapor capture of total loading emissions when vapor capture system is employed. Assumed no vapor capture during maintenance allowance in accordance with 40 CFR 63.561.

Operations Emission Calculations
BMOP - Loading Operations

Hazardous Air Pollutants

Crude Oil HAP Speciation (%)[5]			99% UPL[6]	99% UPL[7]	Nederland Basis[8]	Maximum HAP[9]	Max Hourly Emissions[10]	Avg Hourly Loading Vapors	Annual Emissions	Uncaptured Loading Emissions
HAP	Mass %, liquid	Mass %, vapor	Mass %, liquid	Mass %, vapor	Mass %, vapor	Mass %, vapor	lb/hr	lb/hr	tpy	tpy
Hexane	2.07%	3.11%	3.09%	4.09%	3.38%	4.09%	204.0	186.2	704.1	65.6
Benzene	0.25%	0.19%	0.46%	0.34%	0.80%	0.80%	39.93	36.44	137.8	12.8
Toluene	0.69%	0.20%	1.10%	0.29%	0.36%	0.36%	17.73	16.18	61.18	5.70
Ethylbenzene	0.16%	0.01%	0.29%	0.02%	0.05%	0.05%	2.48	2.26	8.55	0.80
1,2,4-Trimethylbenzene	0.44%	0.007%	0.76%	0.01%		0.01%	0.53	0.49	1.84	0.17
1,3-dimethylbenzene	0.43%	0.04%	0.79%	0.05%		0.05%	2.38	2.17	8.20	0.76
1,4-dimethylbenzene	0.31%	0.03%	0.57%	0.03%		0.03%	1.66	1.51	5.71	0.53
1,2-dimethylbenzene (Xylene)	0.21%	0.01%	0.37%	0.02%	0.21%	0.21%	10.36	9.46	35.76	3.33
i-propylbenzene (Cumene)	0.04%	0.002%	0.08%	0.003%	0.006%	0.01%	0.29	0.27	1.01	0.09
Biphenyl[6]					0.00002%	0.00002%	0.001	0.00	0.003	0.00032
Cresols[6]					0.0007%	0.001%	0.04	0.03	0.12	0.012
Naphthalene[6]					0.0006%	0.001%	0.03	0.03	0.11	0.010
Phenol[6]					0.001%	0.001%	0.07	0.07	0.26	0.024
Total HAP	**4.59%**	**3.60%**	**7.50%**	**4.86%**	**4.80%**	**5.60%**	**279.5**	**255.1**	**965**	**89.9**

[5] Maximum mass % in liquid of individual HAP from 13 samples of various crude types taken at Nederland from May and June 2020 and analyzed per Method D7900, *Standard Test Method for Determination of Light Hydrocarbons in Stabilized Crude Oils by Gas Chromatography*.
Vapor weight percent calculated assuming annual average temperature.
[6] Calculation of the 99% Upper Prediction Limit (UPL) mass percent in liquid, based on the results of the 13 samples from Nederland, by individual HAP.
[7] Calculation of the 99% Upper Prediction Limit (UPL) mass percent in vapor, based on the calculated vapor speciation using results of the 13 samples from Nederland, by individual HAP.
[8] Speciated VOC components, vapor weight %, from the permit basis for the Nederland Terminal, which references Table 3-1 of API Publication 1673 (May 1998), and factors obtained from Mr. James Durham, EPA Office of Air Quality Planning and Standards.
[9] The maximum of the calculated sample mass %, vapor, the Nederland permit basis, or the 99% UPL of the mass %, vapor, by individual HAP.
[10] Calculated as a percent of VOC emissions, as the crude samples demonstrated >99.9% is VOC.
Note that the "Total HAP" is the sum of all max individual HAP from the 13 samples.

Normal Operations Emission Calculations

BMOP - Vapor Combustion Unit Stacks

Total Operating Time [1]	=	8,760	hrs/yr
Operating Load [1]	=	100%	
Total Number of Units [1]	=	3	
Fuel Type [1]	=	VLCC Vapors, Assist Natural Gas, Pilot Natural Gas	
Maximum Heat Input Rate [1]	=	218.09	MMBtu/hr/stack
Average Higher Heating Value (HHV) [2]	=	1,456	MMBtu/MMscf
Vessel Loading Rate [1]	=	80,000	bbl/hr
Waste Gas Molecular Weight [3]	=	50	lb/lbmol
Destruction and Removal Efficiency [1]	=	95	%

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions from 1 Unit	Annual Emissions from 1 Unit	Hourly Emissions from All Units	Annual Emissions from All Units
			Value	Units	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
$PM_{Filterable}$	AP-42	[4],[5]	1.9	lb/MMscf	0.28	1.25	0.85	3.74
$PM_{10, Filterable}$	AP-42	[4],[5]	1.9	lb/MMscf	0.28	1.25	0.85	3.74
$PM_{2.5, Filterable}$	AP-42	[4],[5]	1.9	lb/MMscf	0.28	1.25	0.85	3.74
$PM_{Condensable}$	AP-42	[4]	5.7	lb/MMscf	0.85	3.74	2.56	11.22
NO_x	VCU Estimate	[7]	0.15	lb/MMBtu	32.71	143.3	98.14	429.9
SO_2	Crude H2S Content	[6]	5	ppmw	40.02	4.25	120.1	12.8
CO	VCU Estimate	[7]	0.28	lb/MMBtu	60.08	263.2	180.3	789.5
VOC	Vendor Data	[8]	95	%	82.32	260.2	247.0	780.6
H_2S	Vendor Data	[8]	95	%	1.07	0.11	3.20	0.34

[1] Based on current project design specifications, provided by BMOP and John Zink Hamworthy Combustion (2021), or equivalent. Each vapor combustion unit is assumed to have a maximum heat input rate of 218.09 MMBtu/hr, which is the instantaneous heat input rate at 100% vessel loading, which represents a short-term maximum. The average heat input rate for an entire vessel is far lower.

[2] Heating value of waste gas based on displaced vapors and assist gas usage at Bakken Pipeline during 100% vessel loading.

[3] Vapor molecular weight and H_2S content from crude oil specifications for Nederland Marine Terminal permit, as provided by Energy Transfer on December 6, 2022.

[4] Emission factors from AP-42, Table 1.4-2, Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion (July 1998).

[5] Conservatively assume $PM_{total} = PM_{10} = PM_{2.5}$.

[6] From crude oil specifications provided by Energy Transfer, the annual average H_2S composition is 5 ppmw. SO_2 emissions have been calculated from mass balances, assuming that 100 percent of H_2S (MW = 34) in combusted vapors is oxidized to SO_2 (MW = 64) based on Attachment A of TCEQ's NSR Guidance for Flares and Vapor Combustors: Emission Calculations (March 2021).

[7] NO_X and CO emission factor estimated for VCU sized to fit on the WC 509 Platform Complex.

[8] VOC emissions based on a sea floor annual average temperature of 72.66°F and average TVP of 3 psia and 80,000 bbl/hr, as assumed by John Zink Hamworthy Combustion in VCU specifications (2021), with VCU vendor DRE specifications.

Normal Operations Emission Calculations

BMOP - Vapor Combustion Unit Stacks

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions from 1 Unit	Annual Emissions from 1 Unit	Hourly Emissions from All Units	Annual Emissions from All Units
			Value	Units	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
Hexane	Vendor Data	[8]	95	%	3.37	10.64	10.10	31.92
Benzene	Vendor Data	[8]	95	%	0.66	2.08	1.98	6.25
Toluene	Vendor Data	[8]	95	%	0.29	0.92	0.88	2.77
Ethylbenzene	Vendor Data	[8]	95	%	0.04	0.13	0.12	0.39
1,2,4-Trimethylbenzene	Vendor Data	[8]	95	%	8.80E-03	0.03	0.03	0.08
1,3-dimethylbenzene	Vendor Data	[8]	95	%	0.04	0.12	0.12	0.37
1,4-dimethylbenzene	Vendor Data	[8]	95	%	0.03	0.09	0.08	0.26
1,2-dimethylbenzene (Xylene)	Vendor Data	[8]	95	%	0.17	0.54	0.51	1.62
i-propylbenzene (Cumene)	Vendor Data	[8]	95	%	4.83E-03	0.02	0.01	0.05
Biphenyl	Vendor Data	[8]	95	%	1.65E-05	5.20E-05	4.94E-05	1.56E-04
Cresols	Vendor Data	[8]	95	%	5.93E-04	1.87E-03	1.78E-03	5.62E-03
Naphthalene	Vendor Data	[8]	95	%	5.19E-04	1.64E-03	1.56E-03	4.92E-03
Phenol	Vendor Data	[8]	95	%	1.23E-03	3.88E-03	3.68E-03	1.16E-02
Total VOC HAPs					**4.61**	**14.58**	**13.84**	**43.74**

Normal Operations Emission Calculations

BMOP - Vapor Combustion Unit Stacks

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions from 1 Engine	Annual Emissions from 1 Engine	Hourly Emissions from All Units	Annual Emissions from All Units
			Value	Units	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
CO_2	EPA	[9]	74.54	kg/MMBtu	35,839	156,976	107,518	470,928
CH_4	EPA	[10]	3.00E-03	kg/MMBtu	1.44	6.32	4.33	18.95
N_2O	EPA	[10]	6.00E-04	kg/MMBtu	0.29	1.26	0.87	3.79
CO_2e	EPA	[11]	--	--	**35,961**	**157,510**	**107,884**	**472,531**

[9] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for unfinished oils was used to calculate emissions.

[10] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[11] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

Normal Operations Emission Calculations

BMOP - 509A Low Pressure Flare

Number of Loaded Vessels [1]	=	275	vessels/yr	
Total Operating Time [1]	=	275	hr/yr	
Waste Gas Type [1]	=	VLCC Vapors and Pilot Natural Gas		
Waste Gas Heating Value [2]	=	1,456	Btu/scf	
Waste Gas Molar Flow [3]	=	3.5	MMSCFD	
		145,833	scf/hr	
Crude Oil Specifications				
Vapor Molecular Weight [4]	=	50	lb/lbmol	
Crude Oil Liquid Molecular Weight [4]	=	207	lb/lbmol	
		Maximum	Annual Average	
Liquid H_2S Partition [4]	=	25	21	
H_2S Composition [4]	=	125	25	ppmw

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Low Pressure Flare Emissions	
			Value	Units	(lb/hr)	(tons/yr)
NO_x	High Btu	[5]	0.138	lb/MMBtu	29.3	4.03
CO	High Btu	[5]	0.2755	lb/MMBtu	58.5	8.05
SO_2	Crude H_2S Content	[4],[6]	-	-	13.78	0.32
VOC	Crude Sampling	[4],[7]	-	-	385	52.9

[1] Based on BMOP VLCC ship loading schedule provided on October 24, 2022. The low pressure flare is operated during pigging of the vapor line in a 1-hour period following loading of each vessel. Approximately 275 vessels are unloaded at the platform per year.

[2] Heating value of waste gas based on assist gas usage at Bakken Pipeline during 100% vessel loading.

[3] Flare specifications from Wood provided on December 12, 2022.

[4] Crude oil specifications for Nederland Marine Terminal permit, as provided by Energy Transfer on December 6, 2022.

[5] Emission factor expectations for a high Btu gas stream controlled by a flare that is not steam assisted.

[6] SO_2 emissions have been calculated from mass balances using the crude oil specifications from Energy Transfer, assuming that 100% of H_2S (MW = 34) in flared gas is oxidized to SO_2 (MW = 64) and that all components of the VLCC vapor are VOCs (see note 7).

Example Emissions Calculation (Annual):

SO_2 (tpy) = 5 lb $H_2S/10^6$ lb liquid x (207 lb liquid)/(34 lb H_2S) x (145,833 scf vapor/hr x 50 lb vapor/lb-mol x 1 lbmol/379 scf)/(50 lb/lbmol vapor) x 25 (lbmol H_2S/lbmol vapor) x (64 lb/lbmol SO_2)/(34 lb/lbmol H_2S) x 275 hr/yr x 1 ton/2,000 lbs

[7] Based on the definition of VOCs in 40 CFR 51.100 and the crude oil profile used for permitting of the Nederland Marine Terminal provided by Energy Transfer on March 19, 2020, all components of the VLCC vapor are assumed to be VOCs. VOCs are assumed to have a destruction and removal efficiency (DRE) of 98% in the flare.

Emission Factor Calculation:

VOC (lb/hr) = 145,833 scf/hr x 1 lbmol/379 scf x 50 lb/lbmol x [1 - DRE (%)]

Normal Operations Emission Calculations

BMOP - 509A Low Pressure Flare

Hazardous Air Pollutants

Pollutant	Basis		Composition		Low Pressure Flare Emissions	
			Value	Units	(lb/hr)	(tons/yr)
Hexane	Crude Sampling	[8]	4.09	wt %	15.74	2.16
Benzene	Crude Sampling	[8]	0.80	wt %	3.08	0.42
Toluene	Crude Sampling	[8]	0.36	wt %	1.37	0.19
Ethylbenzene	Crude Sampling	[8]	0.05	wt %	0.19	0.03
1,2,4-Trimethylbenzene	Crude Sampling	[8]	0.01	wt %	0.04	5.66E-03
1,3-Dimethylbenzene	Crude Sampling	[8]	0.05	wt %	0.18	0.03
1,4-Dimethylbenzene	Crude Sampling	[8]	0.03	wt %	0.13	0.02
1,2-Dimethylbenzene	Crude Sampling	[8]	0.21	wt %	0.80	0.11
Cumene	Crude Sampling	[8]	0.01	wt %	0.02	3.11E-03
Total VOC HAPs					**21.55**	**2.96**

[8] Maximum mass % in liquid of individual HAP from 13 samples of various crude types taken at Nederland from May and June 2020 and analyzed per Method D7900, Standard Test Method for Determination of Light Hydrocarbons in Stabilized Crude Oils by Gas Chromatography. Vapor weight percent calculated assuming annual average temperature. VOCs are assumed to have a destruction and removal efficiency (DRE) of 98% in the flare.

Example Calculation (Hexane):

Hexane (lb/hr) = 145,833 scf/hr x 1 lbmol/379 scf x 50 lb vapor/lbmol x 2.07 lb hexane/100 lb vapor x [1 - DRE (%)]

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Low Pressure Flare Emissions	
			Value	Units	(lb/hr)	(tons/yr)
CO_2	EPA	[9]	74.54	kg/MMBtu	34,901	4,799
CH_4	EPA	[10]	3.00E-03	kg/MMBtu	1.40	0.19
N_2O	EPA	[10]	6.00E-04	kg/MMBtu	0.28	0.04
CO_2e	EPA	[11]	--	--	**35,020**	**4,815**

[9] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for unfinished oils was used to calculate emissions.

[10] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[11] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

Normal Operations Emission Calculations

BMOP - 509A High Pressure Flare

Total Operating Time [1]	=	11	hr/event
Events Per Year	=	1	
Waste Gas Type [1]	=	Natural Gas	
Average Waste Gas Higher Heating Value [2]	=	1,020	Btu/scf
Waste Gas Molar Flow [3]	=	32	MMSCFD
		1,333,333	scf/hr

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		High Pressure Flare Emissions	
			Value	Units	(lb/hr)	(tons/yr)
NO_x	High Btu	[4]	0.138	lb/MMBtu	187.7	1.03
CO	High Btu	[4]	0.2755	lb/MMBtu	375	2.06
SO_2	Fuel S Content	[5]	0.17	lb/MMscf	0.23	1.24E-03
VOC	Fuel Content	[4],[6]	18.64	lb/MMscf	24.85	0.14

[1] Based on current project design specifications, provided by BMOP. The high pressure flare is operated during periodic pigging of the natural gas line to the platform. Each pigging event lasts around 11 hours. Pigging is expected to occur once per 7 years, but is conservatively assumed to occur once per year.

[2] Average higher heating value of natural gas from footnote a of AP-42, Table 1.4-1, Emission Factors for Nitrogen Oxides and Carbon Monoxide from Natural Gas Combustion (July 1998).

[3] Flare specifications from Wood provided on December 12, 2022.

[4] Emission factor expectations for a high Btu gas stream controlled by a flare that is not steam assisted.

[5] Based on natural gas from the Stingray system with 0.0001% H2S (by volume). SO_2 emissions have been calculated from mass balances, assuming that 100 percent of sulfur (MW = 32) in combusted fuel is oxidized to SO_2 (MW = 64).

Emission Factor Calculation:

SO_2 (lb/MMscf) = 0.0001 lbmol H_2S/100 lbmol fuel gas x 1 lbmol fuel gas/379 scf x 10^6 scf/1 MMscf x (1 lbmol SO_2)/(1 lbmol H_2S) x 64 lb/lbmol SO_2

[6] VOC emissions found using the fuel gas composition at the WC 509 Platform Complex from the Stingray system. VOCs are assumed to have a generic destruction and removal efficiency (DRE) of 98% and a DRE of 99% for compounds containing no more than 3 carbons.

Example Emission Factor Calculation (Propane):

Propane (lb/MMscf) = 0.84 lbmol propane/100 lbmol fuel gas x 1 lbmol fuel gas/379 scf x 10^6 scf/1 MMscf x 44.1 lb/lbmol propane x [1 - DRE (%)]

VOC	*MW*	*% vol*	*DRE*	*Emissions (lb/MMscf)*
Propane	44.1	0.84	99%	9.77
N-Butane	58.12	0.18	98%	5.52
N-Pentane	72.15	0.04	98%	1.52
Hexane	86.18	0.04	98%	1.82
Total	-	-	-	18.64

Normal Operations Emission Calculations

BMOP - 509A High Pressure Flare

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		High Pressure Flare Emissions	
			Value	Units	(lb/hr)	(tons/yr)
Hexane	Fuel Content	[6]	1.82	lb/MMscf	2.43	1.33E-02
Total VOC HAPs					**2.43**	**1.33E-02**

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		High Pressure Flare Emissions	
			Value	Units	(lb/hr)	(tons/yr)
CO_2	EPA	[8]	53.06	kg/MMBtu	159,089	875
CH_4	Fuel Content, EPA	[9]	5.76E-02	lb/MMBtu	78.31	0.43
N_2O	EPA	[10]	4.32E-06	lb/MMBtu	0.01	3.23E-05
CO_2e	EPA	[11]	--	--	**161,048**	**885.8**

[8] Emission factor for natural gas combustion from 40 CFR 98 Subpart C, Table C-1, Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel.

[9] CH_4 emissions are composed of (i) natural gas combustion by the flare and (ii) releases of uncombusted CH_4 present in the natural gas.

(i) Emission factors for natural gas combustion from 40 CFR 98 Subpart C, Table C-2, Default CH4 and N2O Emission Factors for Various Types of Fuel. The flare is assumed to have a generic destruction and removal efficiency of 98%.

CH_4 from Natural Gas Combustion = 0.98 x (2 x 10^{-5} kg CH_4/MMBtu) x 2.20462 lb/kg = 4.32E-05 lb/MMBtu

(ii) Releases of uncombusted CH_4 found using the fuel gas composition (CH_4 = 92.79 vol% of fuel gas) representative of the Stingray system. CH_4 is assumed to have a destruction and removal efficiency (DRE) of 99%.

Uncombusted CH_4 = 0.01 x 92.79 lbmol CH4/100 lbmol gas x 379 scf/lbmol gas x 1,020 Btu/scf x 1 MMBtu/106 Btu x 16 lb/lbmol CH4 = 5.75E-02 lb/MMBtu

Total CH4 Emission Factor = 5.76E-02 lb/MMBtu

[10] Emission factors for natural gas combustion from 40 CFR 98 Subpart C, Table C-2, Default CH4 and N2O Emission Factors for Various Types of Fuel. The flare is assomed to have a generic destruction and removal efficiency of 98%.

N_2O from Natural Gas Combustion = 0.98 x (2 x 10^{-6} kg CH_4/MMBtu) x 2.20462 lb/kg = 4.32E-06 lb/MMBtu

[11] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

Normal Operations Emission Calculations

BMOP - Platform Natural Gas Generators

Engine Rating [1]	=	1,736	kW
	=	2,328	HP
Total Operating Time [1]	=	8,760	hrs/yr
Operating Load [1]	=	100%	
Total Number of Main Engines [1]	=	1 engine at any one time	
Fuel Type [1]	=	Natural Gas, 4-Stroke Lean Burn	
Average Brake-Specific Fuel Consumption [2]	=	17,820	scf/hr
Average Higher Heating Value (HHV) [4]	=	1,020	Btu/scf
Average Heat Input Rate	=	18.18	MMBtu/hr

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
$PM_{Filterable}$	AP-42	[4]	7.71E-05	lb/MMBtu	1.40E-03	6.14E-03
$PM_{10, Filterable}$	AP-42	[4]	7.71E-05	lb/MMBtu	1.40E-03	6.14E-03
$PM_{2.5, Filterable}$	AP-42	[4]	7.71E-05	lb/MMBtu	1.40E-03	6.14E-03
$PM_{Condensable}$	AP-42	[4]	9.91E-03	lb/MMBtu	0.18	0.79
NO_x	Vendor	[3]	0.5	g/HP-hr	2.57	11.24
SO_2	AP-42	[4]	5.88E-04	lb/MMBtu	0.01	0.05
CO	Vendor	[3]	0.23	g/HP-hr	1.18	5.17
VOC	Vendor	[3]	0.3	g/HP-hr	1.44	6.29
H_2SO_4	Conversion	[5]	5	% of SO_2	5.34E-04	2.34E-03

[1] Based on current project design specifications, provided by BMOP. The BMOP Platform complex will operate 2 engines, however, only one will be operating at any given time.

[2] Per Manufacturer Specification sheet for a Caterpillar G3516C (based on 100% load).

[3] Vendor expected emissions from Caterpillar G3516C with oxidation catalyst. VOC emissions non-methane, non-ethane hydrocarbons, on a methane basis.

[4] Emission factors are based on AP-42 Chapter 3, Table 3.2-2, Uncontrolled Emission Factors for 4-Stroke Lean Burn Engines (July 2000). Assume filterable PM = PM_{10} = $PM_{2.5}$.

[5] Assumes 5% of SO_2 emissions are converted to H_2SO_4; this is a more conservative approach compared to the assumption that 2% of SO_2 emissions are converted to H_2SO_4 as stated in the Toxics Release Inventory Guidance for Reporting Sulfuric Acid, EPA 745-B-20-004 (February 2020).

Normal Operations Emission Calculations

BMOP - Platform Natural Gas Generators

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
Acenaphthene	AP-42	[6]	1.25E-06	lb/MMBtu	2.27E-05	9.95E-05
Acenaphthylene	AP-42	[6]	5.53E-06	lb/MMBtu	1.01E-04	4.40E-04
Acetaldehyde	AP-42	[6]	8.36E-03	lb/MMBtu	0.15	0.67
Acrolein	AP-42	[6]	5.14E-03	lb/MMBtu	0.09	0.41
Benzene	AP-42	[6]	4.40E-04	lb/MMBtu	8.00E-03	0.04
Benzo(b)fluoranthene	AP-42	[6]	1.66E-07	lb/MMBtu	3.02E-06	1.32E-05
Benzo(e)pyrene	AP-42	[6]	4.15E-07	lb/MMBtu	7.54E-06	3.30E-05
Beno(g,h,i)perylene	AP-42	[6]	4.14E-07	lb/MMBtu	7.53E-06	3.30E-05
Biphenyl	AP-42	[6]	2.12E-04	lb/MMBtu	3.85E-03	0.02
Butadiene (1,3-)	AP-42	[6]	2.67E-04	lb/MMBtu	4.85E-03	0.02
Carbon Tetrachloride	AP-42	[6]	3.67E-05	lb/MMBtu	6.67E-04	2.92E-03
Chlorobenzene	AP-42	[6]	3.04E-05	lb/MMBtu	5.53E-04	2.42E-03
Chloroform	AP-42	[6]	2.85E-05	lb/MMBtu	5.18E-04	2.27E-03
Chrysene	AP-42	[6]	6.93E-07	lb/MMBtu	1.26E-05	5.52E-05
Dichloropropene (1,3-)	AP-42	[6]	2.64E-05	lb/MMBtu	4.80E-04	2.10E-03
Ethylbenzene	AP-42	[6]	3.97E-05	lb/MMBtu	7.22E-04	3.16E-03
Ethylene Dibromide	AP-42	[6]	4.43E-05	lb/MMBtu	8.05E-04	3.53E-03
Fluoranthene	AP-42	[6]	1.11E-06	lb/MMBtu	2.02E-05	8.84E-05
Fluorene	AP-42	[6]	5.67E-06	lb/MMBtu	1.03E-04	4.51E-04
Formaldehyde	ZZZZ	[7]	14	ppmvd	0.61	2.67
Methanol	AP-42	[6]	2.50E-03	lb/MMBtu	0.05	0.20
Methylene Chloride	AP-42	[6]	2.00E-05	lb/MMBtu	3.64E-04	1.59E-03
Methylnaphthalene (2-)	AP-42	[6]	3.32E-05	lb/MMBtu	6.03E-04	2.64E-03
n-Hexane	AP-42	[6]	1.11E-03	lb/MMBtu	0.02	0.09
Naphthalene	AP-42	[6]	7.44E-05	lb/MMBtu	1.35E-03	5.92E-03
PAH	AP-42	[6]	2.69E-05	lb/MMBtu	4.89E-04	2.14E-03
Phenanthrene	AP-42	[6]	1.04E-05	lb/MMBtu	1.89E-04	8.28E-04
Phenol	AP-42	[6]	2.40E-05	lb/MMBtu	4.36E-04	1.91E-03
Pyrene	AP-42	[6]	1.36E-06	lb/MMBtu	2.47E-05	1.08E-04
Styrene	AP-42	[6]	2.36E-05	lb/MMBtu	4.29E-04	1.88E-03
Tetrachloroethane	AP-42	[6]	2.48E-06	lb/MMBtu	4.51E-05	1.97E-04
Toluene	AP-42	[6]	4.08E-04	lb/MMBtu	7.42E-03	0.03
Tetrachloroethane (1,1,2,2-)	AP-42	[6]	4.00E-05	lb/MMBtu	7.27E-04	3.18E-03
Trichloroethane (1,1,2-)	AP-42	[6]	3.18E-05	lb/MMBtu	5.78E-04	2.53E-03
Trimethylpentane (2,2,4-)	AP-42	[6]	2.50E-04	lb/MMBtu	4.54E-03	0.02
Vinyl Chloride	AP-42	[6]	1.49E-05	lb/MMBtu	2.71E-04	1.19E-03
Xylene	AP-42	[6]	1.84E-04	lb/MMBtu	3.34E-03	0.01
Total VOC HAPs					**0.96**	**4.22**

[6] Emission factors are based on AP-42 Chapter 3, Table 3.2-2, Uncontrolled Emission Factors for 4-Stroke Lean Burn Engines (July 2000).

[7] Per Table 2a of 40 CFR 63 Subpart ZZZZ, subject 4SLB engines may comply with 14 ppmvd HCHO at 15% O_2.

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
CO_2	Manuf. Spec.	[8]	617	g/kW-hr	2,361	10,343
CH_4	Manuf. Spec.	[8]	6.02	g/kW-hr	23.04	100.9
N_2O	EPA	[9]	1.00E-04	kg/MMBtu	4.01E-03	0.02
CO_2e	EPA	[10]	--	--	**2,939**	**12,871**

[8] Per Manufacturer Specification sheet for a Caterpillar G3516C (based on 100% load).

[9] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for natural gas was used to calculate emissions.

[10] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

Normal Operations Emission Calculations

BMOP - Platform Diesel Generators

Engine Rating [1]	=	336	kW
	=	450	HP
Total Operating Time [1]	=	100	hrs/yr
Operating Load [1]	=	100%	
Total Number of Main Engines [1]	=	1	
Fuel Type [1]	=	Diesel	
Average Brake-Specific Fuel Consumption [2]	=	7,000	Btu/HP-hr
Average Higher Heating Value (HHV) [2]	=	19,300	Btu/lb
Average Heat Input Rate	=	3.15	MMBtu/hr

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
$PM_{Filterable}$	EPA	[3]	0.20	g/kW-hr	0.15	0.01
$PM_{10, Filterable}$	EPA	[3]	0.20	g/kW-hr	0.15	0.01
$PM_{2.5, Filterable}$	EPA	[3]	0.20	g/kW-hr	0.15	0.01
$PM_{Condensable}$	AP-42	[5]	7.70E-03	lb/MMBtu	0.02	1.21E-03
NO_x	EPA	[3]	4.0	g/kW-hr	2.96	0.15
SO_2	Fuel S Content	[4]	7.11E-04	lb/HP-hr	0.32	0.02
CO	EPA	[3]	3.5	g/kW-hr	2.59	0.13
VOC	EPA	[3]	4.0	g/kW-hr	2.96	0.15
H_2SO_4	Fuel S Content	[4]	2.22E-05	lb/HP-hr	0.01	5.00E-04

[1] Based on current project design specifications, provided by BMOP.

[2] Based on AP-42 Chapter 3, Table 3.3-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines (October 1996).

[3] Per 40 CFR 60.4202(a)(2) and Table 3 of Appendix I to 40 CFR 1039. Conservatively assume that NO_X and VOC emissions are equivalent to the NMHC + NO_X emissions limit. Conservatively assume that filterable PM = PM_{10} = $PM_{2.5}$.

[4] A sulfur content of 0.1% is used for all diesel combustion sources per IMO 2015 standards. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98% of sulfur in the fuel is oxidized to SO2 (MW = 32 g/mol) and 2% of sulfur in the fuel is oxidized to H2SO4 (MW = 98 g/mol) based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

[5] Conservatively based on AP-42 Chapter 3, Table 3.4-2, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

Normal Operations Emission Calculations
BMOP - Platform Diesel Generators

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
Acetaldehyde	AP-42	[6], [7]	7.67E-04	lb/MMBtu	2.42E-03	1.21E-04
Acrolein	AP-42	[6], [7]	9.25E-05	lb/MMBtu	2.91E-04	1.46E-05
Benzene	AP-42	[6], [7]	9.33E-04	lb/MMBtu	2.94E-03	1.47E-04
1,3-Butadiene	AP-42	[6], [7]	3.91E-05	lb/MMBtu	1.23E-04	6.16E-06
Formaldehyde	AP-42	[6], [7]	1.18E-03	lb/MMBtu	3.72E-03	1.86E-04
Toluene	AP-42	[6], [7]	4.09E-04	lb/MMBtu	1.29E-03	6.44E-05
Xylenes	AP-42	[6], [7]	2.85E-04	lb/MMBtu	8.98E-04	4.49E-05
Total PAH	AP-42	[6], [7]	1.68E-04	lb/MMBtu	5.29E-04	2.65E-05
Total VOC HAPs					**1.22E-02**	**6.10E-04**

[6] Emission factors based on AP-42, Chapter 3, Table 3.3-2, Speciated Organic Compound Emission Factors for Uncontrolled Stationary Diesel Engines (October 1996).

[7] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
CO_2	EPA	[8], [11]	73.96	kg/MMBtu	514	25.7
CH_4	EPA	[9], [11]	3.00E-03	kg/MMBtu	2.08E-02	1.04E-03
N_2O	EPA	[9], [11]	6.00E-04	kg/MMBtu	4.17E-03	2.08E-04
CO_2e	EPA	[10]	--	--	**515**	**25.8**

[8] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[9] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[10] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

[11] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Normal Operations Emission Calculations

BMOP - Platform B Cranes

Engine Rating [1]	=	354	kW
	=	475	HP
Total Operating Time [1]	=	4,380	hrs/yr
Operating Load [1]	=	100%	
Total Number of Gen Sets [1]	=	2	
Fuel Type [1]	=	Diesel	
Average Brake-Specific Fuel Consumption [2]	=	7,000	Btu/HP-hr
Average Higher Heating Value (HHV) [2]	=	19,300	Btu/lb
Average Heat Input Rate	=	3.33	MMBtu/hr

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions from 1 Engine	Annual Emissions from 1 Engine	Hourly Emissions from All Engines	Annual Emissions from All Engines
			Value	Units	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
$PM_{Filterable}$	EPA	[3], [4]	3.00E-02	g/kW-hr	0.02	0.05	0.05	0.10
$PM_{10, Filterable}$	EPA	[3], [4]	3.00E-02	g/kW-hr	0.02	0.05	0.05	0.10
$PM_{2.5, Filterable}$	EPA	[3], [4]	3.00E-02	g/kW-hr	0.02	0.05	0.05	0.10
$PM_{Condensable}$	AP-42	[5]	5.39E-05	lb/HP-hr	2.56E-02	5.61E-02	0.05	0.11
NO_x	EPA	[3]	0.60	g/kW-hr	0.47	1.03	0.94	2.05
SO_2	Fuel S Content	[6]	7.11E-04	lb/HP-hr	0.34	0.74	0.68	1.48
CO	EPA	[3]	3.5	g/kW-hr	2.73	5.99	5.47	11.97
VOC	EPA	[3]	0.285	g/kW-hr	0.22	0.49	0.45	0.97
H_2SO_4	Fuel S Content	[6]	2.22E-05	lb/HP-hr	1.06E-02	2.31E-02	2.11E-02	4.62E-02

[1] Based on current project design specifications, provided by BMOP.

[2] Based on AP-42 Chapter 3, Table 3.3-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines (October 1996).

[3] Per 40 CFR 60.4204(b) and Table 1 of 40 CFR 1039.101. Per 40 CFR 1039.101(e), emissions of PM, NO_X, and VOC are multiplied by the appropriate NTE multiplier.

[4] Conservatively assume $PM_{10} = PM_{2.5}$.

[5] Conservatively based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[6] A sulfur content of 0.1% is used for all diesel combustion sources per IMO 2015 standards. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98% of sulfur in the fuel is oxidized to SO2 (MW = 32 g/mol) and 2% of sulfur in the fuel is oxidized to H2SO4 (MW = 98 g/mol) based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

Normal Operations Emission Calculations

BMOP - Platform B Cranes

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions from 1 Engine	Annual Emissions from 1 Engine	Hourly Emissions from All Engines	Annual Emissions from All Engines
			Value	Units	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
Acetaldehyde	AP-42	[7], [8]	7.67E-04	lb/MMBtu	2.55E-03	5.59E-03	5.10E-03	1.12E-02
Acrolein	AP-42	[7], [8]	9.25E-05	lb/MMBtu	3.08E-04	6.74E-04	6.15E-04	1.35E-03
Benzene	AP-42	[7], [8]	9.33E-04	lb/MMBtu	3.10E-03	6.79E-03	6.20E-03	1.36E-02
1,3-Butadiene	AP-42	[7], [8]	3.91E-05	lb/MMBtu	1.30E-04	2.85E-04	2.60E-04	5.69E-04
Formaldehyde	AP-42	[7], [8]	1.18E-03	lb/MMBtu	3.92E-03	8.59E-03	7.85E-03	1.72E-02
Toluene	AP-42	[7], [8]	4.09E-04	lb/MMBtu	1.36E-03	2.98E-03	2.72E-03	5.96E-03
Xylenes	AP-42	[7], [8]	2.85E-04	lb/MMBtu	9.48E-04	2.08E-03	1.90E-03	4.15E-03
Total PAH	AP-42	[7], [8]	1.68E-04	lb/MMBtu	5.59E-04	1.22E-03	1.12E-03	2.45E-03
Total VOC HAPs					**1.29E-02**	**2.82E-02**	**2.58E-02**	**5.64E-02**

[7] Emission factors based on AP-42, Chapter 3, Table 3.3-2, Speciated Organic Compound Emission Factors for Uncontrolled Stationary Diesel Engines (October 1996).

[8] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions from 1 Engine	Annual Emissions from 1 Engine	Hourly Emissions from All Engines	Annual Emissions from All Engines
			Value	Units	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
CO_2	EPA	[9], [12]	73.96	kg/MMBtu	542.2	1,187.3	1,084.3	2,375
CH_4	EPA	[10], [12]	3.00E-03	kg/MMBtu	2.20E-02	4.82E-02	4.40E-02	9.63E-02
N_2O	EPA	[10], [12]	6.00E-04	kg/MMBtu	4.40E-03	9.63E-03	8.80E-03	1.93E-02
CO_2e	EPA	[11]	--	--	**544.0**	**1,191.4**	**1,088.0**	**2,383**

[9] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[10] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[11] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

[12] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Normal Operations Emission Calculations

BMOP - Platform B Firewater Pumps

Engine Rating [1]	=	485	kW
	=	650	HP
Total Operating Time [1]	=	100	hrs/yr
Operating Load [1]	=	100%	
Fuel Type [1]	=	Diesel	
Average Brake-Specific Fuel Consumption [2]	=	7,000	Btu/HP-hr
Average Higher Heating Value (HHV) [2]	=	19,300	Btu/lb
Average Heat Input Rate	=	4.55	MMBtu/hr

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
$PM_{Filterable}$	EPA	[3], [4]	0.15	g/HP-hr	0.21	0.01
$PM_{10, Filterable}$	EPA	[3], [4]	0.15	g/HP-hr	0.21	0.01
$PM_{2.5, Filterable}$	EPA	[3], [4]	0.15	g/HP-hr	0.21	0.01
$PM_{Condensable}$	AP-42	[5]	5.39E-05	lb/HP-hr	3.50E-02	1.75E-03
NO_x	EPA	[3]	3.00	g/HP-hr	4.30	0.21
SO_2	Fuel S Content	[6]	7.11E-04	lb/HP-hr	0.46	0.02
CO	EPA	[3]	2.60	g/HP-hr	3.73	0.19
VOC	EPA	[3]	3.00	g/HP-hr	4.30	0.21
H_2SO_4	Fuel S Content	[6]	2.22E-05	lb/HP-hr	1.44E-02	7.22E-04

[1] Based on current project design specifications, provided by BMOP.

[2] Based on AP-42 Chapter 3, Table 3.3-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines (October 1996).

[3] Per 40 CFR 60.4205(c) and Table 4 of NSPS Subpart IIII. Conservatively assume that NO_X and VOC emissions are equivalent to the NMHC + NO_X emissions limit.

[4] Conservatively assume $PM_{10} = PM_{2.5}$.

[5] AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[6] A sulfur content of 0.1% is used for all diesel combustion sources per IMO 2015 standards. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98% of sulfur in the fuel is oxidized to SO2 (MW = 32 g/mol) and 2% of sulfur in the fuel is oxidized to H2SO4 (MW = 98 g/mol) based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

Normal Operations Emission Calculations

BMOP - Platform B Firewater Pumps

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
Acetaldehyde	AP-42	[7], [8]	2.52E-05	lb/MMBtu	1.15E-04	5.73E-06
Acrolein	AP-42	[7], [8]	7.88E-06	lb/MMBtu	3.59E-05	1.79E-06
Benzene	AP-42	[7], [8]	7.76E-04	lb/MMBtu	3.53E-03	1.77E-04
Formaldehyde	AP-42	[7], [8]	7.89E-05	lb/MMBtu	3.59E-04	1.79E-05
Toluene	AP-42	[7], [8]	2.81E-04	lb/MMBtu	1.28E-03	6.39E-05
Xylenes	AP-42	[7], [8]	1.93E-04	lb/MMBtu	8.78E-04	4.39E-05
Total PAH	AP-42	[7], [8]	2.12E-04	lb/MMBtu	9.65E-04	4.82E-05
Total VOC HAPs					**7.16E-03**	**3.58E-04**

[7] Emission factors based on AP-42, Chapter 3, Table 3.4-3, Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[8] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Normal Operations Emission Calculations

BMOP - Platform B Firewater Pumps

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
CO_2	EPA	[9], [12]	73.96	kg/MMBtu	741.9	37.09
CH_4	EPA	[10], [12]	3.00E-03	kg/MMBtu	3.01E-02	1.50E-03
N_2O	EPA	[10], [12]	6.00E-04	kg/MMBtu	6.02E-03	3.01E-04
CO_2e	EPA	[11]	--	--	**744.4**	**37.22**

[9] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[10] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[11] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

[12] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Normal Operations Emission Calculations

BMOP - Platform C Firewater Pumps

Engine Rating [1]	=	485	kW
	=	650	HP
Total Operating Time [1]	=	100	hrs/yr
Operating Load [1]	=	100%	
Fuel Type [1]	=	Diesel	
Average Brake-Specific Fuel Consumption [2]	=	7,000	Btu/HP-hr
Average Higher Heating Value (HHV) [2]	=	19,300	Btu/lb
Average Heat Input Rate	=	4.55	MMBtu/hr

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
$PM_{Filterable}$	EPA	[3], [4]	0.15	g/HP-hr	0.21	0.01
$PM_{10, Filterable}$	EPA	[3], [4]	0.15	g/HP-hr	0.21	0.01
$PM_{2.5, Filterable}$	EPA	[3], [4]	0.15	g/HP-hr	0.21	0.01
$PM_{Condensable}$	AP-42	[5]	5.39E-05	lb/HP-hr	3.50E-02	1.75E-03
NO_x	EPA	[3]	3.00	g/HP-hr	4.30	0.21
SO_2	Fuel S Content	[6]	7.11E-04	lb/HP-hr	0.46	0.02
CO	EPA	[3]	2.60	g/HP-hr	3.73	0.19
VOC	EPA	[3]	3.00	g/HP-hr	4.30	0.21
H_2SO_4	Fuel S Content	[6]	2.22E-05	lb/HP-hr	1.44E-02	7.22E-04

[1] Based on current project design specifications, provided by BMOP.

[2] Based on AP-42 Chapter 3, Table 3.3-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines (October 1996).

[3] Per 40 CFR 60.4205(c) and Table 4 of NSPS Subpart IIII. Conservatively assume that NO_X and VOC emissions are equivalent to the NMHC + NO_X emissions limit.

[4] Conservatively assume $PM_{10} = PM_{2.5}$.

[5] AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[6] A sulfur content of 0.1% is used for all diesel combustion sources per IMO 2015 standards. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98% of sulfur in the fuel is oxidized to SO2 (MW = 32 g/mol) and 2% of sulfur in the fuel is oxidized to H2SO4 (MW = 98 g/mol) based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

Normal Operations Emission Calculations

BMOP - Platform C Firewater Pumps

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
Acetaldehyde	AP-42	[7], [8]	2.52E-05	lb/MMBtu	1.15E-04	5.73E-06
Acrolein	AP-42	[7], [8]	7.88E-06	lb/MMBtu	3.59E-05	1.79E-06
Benzene	AP-42	[7], [8]	7.76E-04	lb/MMBtu	3.53E-03	1.77E-04
Formaldehyde	AP-42	[7], [8]	7.89E-05	lb/MMBtu	3.59E-04	1.79E-05
Toluene	AP-42	[7], [8]	2.81E-04	lb/MMBtu	1.28E-03	6.39E-05
Xylenes	AP-42	[7], [8]	1.93E-04	lb/MMBtu	8.78E-04	4.39E-05
Total PAH	AP-42	[7], [8]	2.12E-04	lb/MMBtu	9.65E-04	4.82E-05
Total VOC HAPs					**7.16E-03**	**3.58E-04**

[7] Emission factors based on AP-42, Chapter 3, Table 3.4-3, Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[8] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Normal Operations Emission Calculations

BMOP - Platform C Firewater Pumps

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
CO_2	EPA	[9], [12]	73.96	kg/MMBtu	741.9	37.09
CH_4	EPA	[10], [12]	3.00E-03	kg/MMBtu	3.01E-02	1.50E-03
N_2O	EPA	[10], [12]	6.00E-04	kg/MMBtu	6.02E-03	3.01E-04
CO_2e	EPA	[11]	--	--	**744.4**	**37.22**

[9] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[10] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[11] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

[12] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

BMOP - Deepwater Port WC509 platform
Tank Emissions

Platform	Tank ID	Roof Type	Standing Losses (tpy)	Working Losses (tpy)	Total VOC Losses (tpy)	Total HAP Losses (tpy)
WC509	Aviation Fuel Storage[1]	Horizontal Tank	2.90E-04	2.22E-04	5.12E-04	7.65E-05
	Crane Diesel Tank No. 1[2]	FRT (no floating roof)	4.14E-04	1.52E-03	1.93E-03	2.65E-04
	Crane Diesel Tank No. 2[2]	FRT (no floating roof)	4.14E-04	1.52E-03	1.93E-03	2.65E-04
	Primary Diesel Storage Tank[2]	Horizontal Tank	2.23E-03	6.28E-03	0.01	1.17E-03
	Surge Tank	Horizontal Tank	3.57	0.17	3.73	0.07
				Totals:	**3.74**	**0.07**

[1] TankESP default Jet Kerosene is used as a product for this tank.
[2] TankESP default Diesel stock is used as product for this tank.

BMOP - Deepwater Port WC509 platforn
Tank Emissions

Platform	Tank ID	HAP Emissions (lb/yr)										
		Benzo(g,h,i)perylene	Biphenyl	Cumene	Cyclohexane	Ethylcyclohexane	Hexanol (1)	Neopentane {dimethylpropane (2,2)}	Pentane (n-)	Toluene diisocyanate	Trimethylbenzene (1,3,5)	Xylene (m-)
WC509	Aviation Fuel Storage[1]	6.91E-03	2.41E-16	-	-	2.07E-02	1.39E-02	3.31E-04	3.58E-14	6.70E-02	-	4.42E-02
	Crane Diesel Tank No. 1[2]	7.71E-03	2.95E-15	-	-	1.18E-02	1.55E-03	1.74E-03	6.41E-13	8.98E-02	1.88E-01	2.30E-01
	Crane Diesel Tank No. 2[2]	7.71E-03	2.95E-15	-	-	1.18E-02	1.55E-03	1.74E-03	6.41E-13	8.98E-02	1.88E-01	2.30E-01
	Primary Diesel Storage Tank[2]	3.39E-02	1.33E-14	-	-	5.21E-02	6.81E-03	7.69E-03	2.88E-12	3.95E-01	8.27E-01	1.01
	Surge Tank	33.2	9.34E-15	2.54E-01	39.8	2.13	35.5	5.13E-03	9.94E-12	16.3	3.69E-01	6.53
		33.28	**2.87E-14**			**2.23**	**35.48**	**1.66E-02**	**1.41E-11**	**16.92**	**1.57**	**8.05**

[1] TankESP default Jet Kerosene is used as a product for t
[2] TankESP default Diesel stock is used as product for this

BMOP - Deepwater Port WC509 platform
Fugitive Emissions

Source	Contents	Platform	Service	Equipment Counts: Valves	Flanges/Connectors	Pumps	Vapor/Gas Relief Valves	Compressors	Process Drains	Sampling Connections	Total VOC[1] (lb/hr)	Total VOC[2] (tpy)	Total HAP[3] (lb/hr)	Total HAP[2] (tpy)	Total H_2S[4] (lb/hr)	Total H_2S[2,4] (tpy)	Total CO_2e[5] (lb/hr)	Total CO_2e[2] (tpy)
Fuel Gas Scrubber	Natural Gas	509B	Gas/Vapor	21	22	0	2	0	4	0	0.07	0.30	6.74E-03	0.03	0	0	17.51	76.68
Condensate Pump No. 1	Natural Gas	509A	Gas/Vapor	20	15	1	1	0	2	0	0.05	0.22	4.86E-03	0.02	0	0	12.62	55.28
Condensate Pump No. 2	Natural Gas	509A	Gas/Vapor	20	15	1	1	0	2	0	0.05	0.22	4.86E-03	0.02	0	0	12.62	55.28
Pig Launcher No. 1 (Gas Export)	Natural Gas	509A	Gas/Vapor	63	126	0	0	0	8	8	0.13	0.58	0.01	0.06	0	0	33.84	148.21
Pig Launcher No. 2 (Gas Export)	Natural Gas	509A	Gas/Vapor	63	126	0	0	0	8	8	0.13	0.58	0.01	0.06	0	0	33.84	148.21
Pig Receiver (Oil Import)	Crude Oil	509A	Light Liquid	9	17	0	0	0	4	0	0.10	0.45	5.82E-03	0.03	1.34E-03	1.98E-04	0	0
Crude Oil Mainline	Crude Oil	509A	Light Liquid	9	17	0	0	0	4	0	0.10	0.45	5.82E-03	0.03	1.34E-03	1.98E-04	0	0
Oil Meter Skid	Crude oil	509B	Light Liquid	52	105	0	0	0	6	1	0.57	2.50	0.03	0.14	7.39E-03	1.09E-03	0	0
Meter Prover Skid	Crude Oil	509B	Light Liquid	8	16	0	0	0	1	0	0.08	0.36	4.65E-03	0.02	1.07E-03	1.58E-04	0	0
Pig Launcher No. 1 (Export to VLCC)	Crude Oil	509B	Light Liquid	18	34	0	0	0	8	0	0.21	0.91	0.01	0.05	2.69E-03	3.95E-04	0	0
Pig Launcher No. 2 (Export to VLCC)	Crude Oil	509B	Light Liquid	18	34	0	0	0	8	0	0.21	0.91	0.01	0.05	2.69E-03	3.95E-04	0	0
CALM Buoy #1	Crude Oil	--	Light Liquid	20	50	0	0	0	0	0	0.20	0.89	0.01	0.05	2.63E-03	3.87E-04	0	0
CALM Buoy #2	Crude Oil	--	Light Liquid	20	50	0	0	0	0	0	0.20	0.89	0.01	0.05	2.63E-03	3.87E-04	0	0
Surge Relief Valve Skid	Crude Oil	509B	Light Liquid	20	18	0	0	0	2	0	0.19	0.85	0.01	0.05	2.52E-03	3.71E-04	0	0
Surge Tank	Crude Oil	509B	Light Liquid	12	22	2	0	0	1	0	0.21	0.92	0.01	0.05	2.71E-03	3.99E-04	0	0
Surge Tank Pump No. 1	Crude Oil	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	2.43E-03	0.01	5.61E-04	8.26E-05	0	0
Surge Tank Pump No. 2	Crude Oil	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	2.43E-03	0.01	5.61E-04	8.26E-05	0	0
Sump System No. 1	Crude Oil	509B	Light Liquid	15	32	2	0	0	3	0	0.25	1.09	0.01	0.06	3.22E-03	4.74E-04	0	0
Sump System No. 2	Crude Oil	509C	Light Liquid	15	32	2	0	0	3	0	0.25	1.09	0.01	0.06	3.22E-03	4.74E-04	0	0
Firewater Pump No. 1	Diesel Fuel	509B	Light Liquid	5	6	0	0	0	1	0	0.05	0.22	7.04E-03	0.03	0	0	0	0
Firewater Pump No. 2	Diesel Fuel	509C	Light Liquid	5	6	0	0	0	1	0	0.05	0.22	7.04E-03	0.03	0	0	0	0
Air Compressor No. 1	Diesel Fuel	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	5.96E-03	0.03	0	0	0	0
Air Compressor No. 2	Diesel Fuel	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	5.96E-03	0.03	0	0	0	0
Crane Diesel Tank No. 1	Diesel Fuel	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	5.96E-03	0.03	0	0	0	0
Platform Crane No. 1	Diesel Fuel	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	5.96E-03	0.03	0	0	0	0
Platform Crane No. 2	Diesel Fuel	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	5.96E-03	0.03	0	0	0	0
Diesel Transfer Skid	Diesel Fuel	509B	Light Liquid	18	30	2	0	0	1	0	0.27	1.17	0.04	0.16	0	0	0	0
LQ Crane	Diesel Fuel	509C	Light Liquid	18	30	2	0	0	1	0	0.27	1.17	0.04	0.16	0	0	0	0
Diesel Transfer Pump No. 1	Diesel Fuel	509B	Light Liquid	18	30	2	0	0	1	0	0.27	1.17	0.04	0.16	0	0	0	0
Diesel Transfer Pump No. 2	Diesel Fuel	509B	Light Liquid	18	30	2	0	0	1	0	0.27	1.17	0.04	0.16	0	0	0	0
Gas Generator No. 1	Natural Gas	509B	Gas/Vapor	10	11	0	0	0	2	0	0.01	0.07	1.47E-03	6.44E-03	0	0	3.82	16.72
Gas Generator No. 2	Natural Gas	509B	Gas/Vapor	10	11	0	0	0	2	0	0.01	0.07	1.47E-03	6.44E-03	0	0	3.82	16.72
Emergency Diesel Generator	Diesel Fuel	509B	Light Liquid	5	6	0	0	0	1	0	0.05	0.22	7.04E-03	0.03	0	0	0	0
Knockout System	Natural Gas	509B	Gas/Vapor	30	40	0	2	0	2	0	0.08	0.36	8.20E-03	0.04	0	0	21.30	93.30
Fuel Gas Skid	Natural Gas	509B	Gas/Vapor	68	81	0	6	0	13	5	0.23	1.00	0.02	0.10	0	0	58.66	256.92
Aviation Refueling System No. 1	Aviation Fuel	509B	Light Liquid	6	20	1	0	0	1	0	0.11	0.49	0.11	0.49	0	0	0	0
Aviation Refueling System No. 2	Aviation Fuel	509C	Light Liquid	6	20	1	0	0	1	0	0.11	0.49	0.11	0.49	0	0	0	0
Three (3) VCU Systems	Natural Gas	509A	Gas/Vapor	36	72	0	3	4	4	3	0.29	1.28	0.03	0.13	0	0	74.67	327.04
High Pressure Flare Scrubber and Pump	Natural Gas	VBT	Gas/Vapor	2	4	1	0	0	1	0	7.32E-03	0.03	7.23E-04	3.17E-03	0	0	1.88	8.22
Low Pressure Flare	Natural Gas	VBT	Gas/Vapor	2	4	1	0	0	1	0	7.32E-03	0.03	7.23E-04	3.17E-03	0	0	1.88	8.22
											5.41	23.69	0.68	2.96	0.03	5.09E-03	276.4	1,211

[1] Emission factors based on EPA's Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017 https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf
[2] Based on continous operation (e.g. 8,760 hours per year).
[3] HAP emissions are based on the speciation of:
- Natural Gas Composition and Properties based on an April 13, 2020 sample at WC509.
- Diesel fuel HAP content consistent with tank emissions speciation.
- Crude Oil speciation per the maximum mass %, vapor values calculated for crude oil loading emissions.

[4] H2S emissions are calculated based on the mass balance and liquid H2S parition factors from the Petroleum Processing Handbook, McGraw-Hill, New York, Figure 12-71, page 12-93. Short-term and annual H2S consistent with loading emissions.
[5] CO2 and CH4 speciation of natural gas based on an April 13, 2020 sample at WC509. CH4 and CO2 CO2e, weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

APPENDIX D. BACT SUPPORTING DOCUMENTATION

RBLC Database Summary Tables

RBLC – VOC

- Process Type 42.004/42.010 – Petroleum/Volatile Organic Liquid Marketing
- Process Type 17.130 – Large Natural Gas Engines
- Process Type 17.110 – Large Emergency Diesel Engines
- Process Type 17.210 – Small Emergency Diesel Engines
- Process Type 17.210 – Small Non-Emergency Diesel Engines
- Process Type 42.004 – Marketing Terminal Fugitive Emissions
- Process Type 42.005 – Storage Tanks

Marine Loading Operations - VOC

RBLCID	State	Facility	Process Name	Throughput	Throughput Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Case-by-Case Basis	Permit Date
TX-0731	TX	Corpus Christi Terminal Condensate Splitter	Marine Vessel Loading	20,000	BBL/HR	VOC	For products with vapor pressure (VP) < 0.5 psia, use of bottom or submerged fill; for products with VP ≥ 0.5 psia, loading under vacuum (for non-inert vessels), loading into MACT Y vapor-tight vessels (for inert vessels), and use of a vapor combustor with a guaranteed DRE of 99.5%. For line/hose disconnects, isolation of line/hose, draining line/hose into receiving vessel or sump, and capping line/hose after drainage.						BACT-PSD	4/10/2015
TX-0745	TX	Texas Dock and Rail	Marine Vessel Loading	157	MMBBL/YR	VOC	For products with VP ≥ 0.5 psia, vapors directed to vapor recovery unit limiting emissions to 10 mg/L. Inerted cargo tanks must have passed annual vapor tightness test as specified in 40 CFR 61.304(f).	74.35	TPY		126.32	TPY	BACT-PSD	6/3/2015
TX-0752	TX	Ingleside Terminal	Barge and Ship Loading	110	MBBL/YR	VOC	Vapor combustor unit (VCU).	126.1	TPY				BACT-PSD	6/22/2015
TX-0756	TX	CCI Corpus Christi Condensate Splitter Facility	Barge Loading	507,974,880	GAL/YR	VOC	For loading of gas oil (VP < 0.5 psia), no controls necessary.	48.01	LB/HR		19.19	TPY	BACT-PSD	6/19/2015
TX-0756	TX	CCI Corpus Christi Condensate Splitter Facility	Ship Loading	507,974,880	GAL/YR	VOC	For loading of gas oil (VP < 0.5 psia), no controls necessary.	208.6	LB/HR		294.97	TPY	BACT-PSD	6/19/2015
TX-0765	TX	Sunoco Marine Vessel Loading Operations	Marine Vessel Loading	100	MMBBL/YR	VOC	Use of bottom/submerged fill lines for all products. For products with VP ≥ 0.5 psia, loading under a vacuum (for non-inerted vessels), or into a vapor-tight vessels (for inerted vessels) with emissions being routed to a VCU with a guaranteed DRE of 99%.	97.36	TPY				BACT-PSD	9/18/2015
TX-0772	TX	Port of Beaumont Petroleum Transload Terminal (PBPTT)	Marine Vessel Loading	45,000	BBL/HR	VOC	For products with VP ≥ 0.5 psia, loading under vacuum (non-inerted vessels), loading into MACT Y vapor-tight vessels (inerted vessels), and use of a VCU with a guaranteed DRE of 99%.	755.88	TPY		660.32	TPY	BACT-PSD	11/6/2015
TX-0799	TX	Beaumont Terminal	Marine Loading			VOC	For products with VP ≥ 0.5 psia, loading into MACT-Y vapor tight vessels. Capture efficiency is 99.8% for ocean-going vessels. Captured emissions are routed to a VCU.	24.5	TPY				BACT-PSD	6/8/2016
TX-0800	TX	Corpus Crude Oil Terminal	Marine Loading	20,000,000	BBL/YR	VOC	For products with VP ≥ 0.5 psia, loading into MACT-Y vapor tight vessels. Capture efficiency is 95% for ocean-going vessels. Captured emissions are routed to a VCU.	351.1	TPY				BACT-PSD	6/22/2016
TX-0808	TX	Houston Fuel Oil Terminal	Marine Loading	67,600,600	BBL/YR	VOC	Ships leak tested to verify 99.5% collection efficiency per 40 CFR 63.565(c) or 40 CFR 61.304(f). Marine loading controlled by VCU with 99.9% DRE.						LAER	9/2/2016
TX-0818	TX	Fuel Oil Terminal	Marine Loading	30,000	BBL/HR	VOC	Ships leak tested to verify 99.5% collection efficiency per 40 CFR 63.565(c) or 40 CFR 61.304(f). Marine loading controlled by VCU with 99.9% DRE.						LAER	4/26/2017
TX-0825	TX	Pasadena Terminal	Marine Vessel Ship Loading	30,000	BBL/HR	VOC	Vapor recovery units (VRU).	1	mg/L		71.36	TPY	LAER	7/14/2017
TX-0825	TX	Pasadena Terminal	Marine Barge Loading			VOC	100% of vapors will be captured with vacuum loading and routed to a VRU.	71.36	TPY				LAER	7/14/2017
TX-0844	TX	Oxy Ingleside Energy Center	Marine Loading			VOC	100% of vapors are captured and routed to a VCU.						BACT-PSD	7/25/2018
TX-0852	TX	Corpus Christi Waterfront Terminal	Marine Loading			VOC	Vapors are captured and routed to a VCU.						BACT-PSD	1/2/2019
TX-0855	TX	Buckeye South Texas Gateway Terminal	Marine Vessel Loading			VOC	Vapors are captured and routed to a VCU.						BACT-PSD	3/13/2019
TX-0855	TX	Buckeye South Texas Gateway Terminal	Marine Vessel Loading during Maintenance, Startup, and Shutdown via Vacuum Truck			VOC	Carbon adsorption system.	100	PPMV	BREAKTHROUGH			BACT-PSD	3/13/2019
TX-0872	TX	Condensate Splitter Facility	Marine Loading with a Non-inert Barge (VP ≤ 0.5 psia)	13,249,500	BBL/YR	VOC	Equipped with submerged fill pipes; 100% collection efficiency with vacuum loading.						BACT-PSD	10/31/2019
TX-0872	TX	Condensate Splitter Facility	Marine Loading with a Non-inert Barge (VP > 0.5 psia)	13,249,500	BBL/YR	VOC	Vacuum loading with 100% collection efficiency; vapors routed to the marine VCUs.						BACT-PSD	10/31/2019
TX-0872	TX	Condensate Splitter Facility	Marine Loading with Ship and Inert Barges (VP > 0.5 psia)	13,249,500	BBL/YR	VOC	Annual tightness testing via 40 CFR 63.565(c) or 40 CFR 61.304(f). AVO once every 8 hrs. 99% collection efficiency. Maintain vessel cargo tank above 0.2% psig.						BACT-PSD	10/31/2019
TX-0872	TX	Condensate Splitter Facility	Marine Loading with Ship and Inert Barges (VP > 0.5 psia)	13,249,500	BBL/YR	VOC	Annual tightness testing via 40 CFR 63.565(c) or 40 CFR 61.304(f). AVO once every 8 hrs. Vapors routed to one of the marine VCU with 99% collection efficiency and 99.5% DRE. Maintain vessel cargo tank above 0.2% psig.						BACT-PSD	10/31/2019
TX-0879	TX	Motiva Port Arthur Terminal	Ship and Barge Loading Losses	142,370,242	BBL/YR	VOC	Controlled loading of materials with VP > 0.5 psia. Barge loading will utilize vacuum loading for 100% collection efficiency. 99% collection efficiency is claimed for ship loading. Collected emissions are controlled by a vapor combustor.						BACT-PSD	2/19/2020

Large Natural Gas Generators - VOC

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
CA-1240	CA	Gold Coast Packing	Internal Combustion Engine	Natural Gas	881	BHP	VOC	Oxidation catalyst.	25	PPMVD	@15% O2				OTHER CASE-BY-CASE	3/17/2017
FL-0370	FL	Arvah B. Hopkins Generating Station	SI Internal Combustion Engine Units 1A-1E	Natural Gas	18.82	MW	VOC	Oxidation catalyst.	26	PPMVD AT 15% O2	& 4.92 LB/HOUR AT 70% AND 100% LOAD	42	PPMVD AT 15% O2	& 3.60 LB/HOUR AT 40% LOAD	BACT-PSD	4/3/2019
KS-0030	KS	Mid-Kansas Electric Company, LLC - Rubart Station	Spark Ignition RICE Electricity Generating Units (EGUs)	Natural Gas	10	MW	VOC		5.82	LB/HR	1-HR AVE. PERIOD, EXCEPT DURING STARTUP	8.44	LB/HR	3-HR AVE. PERIOD, DURING STARTUP	BACT-PSD	3/31/2016
KS-0035	KS	Lacey Randall Generation Facility, LLC	Spark Ignition 4SLB RICE Electric Generating Units (EGUs)	Natural Gas	12526	BHP	VOC	Selective catalytic reduction (SCR) system; oxidation catalyst.	2.67	LB/HR	1-HR AVERAGING, EXCLUDING STARTUP	4.21	LB/HR	3-HR AVERAGING, DURING STARTUP	BACT-PSD	1/24/2014
LA-0292	LA	Holbrook Compressor Station	Waukesha 16V-275GL Compressor Engines Nos. 1-12	Natural Gas	5000	HP	VOC	CO oxidation catalyst, use of natural gas as fuel, good equipment design, and proper combustion techniques	1.25	LB/HR	HOURLY MAXIMUM	5.46	TPY	ANNUAL MAXIMUM	BACT-PSD	1/22/2016
MI-0440	MI	Michigan State University	Flexible Group (FG) Engines - 4 RICE	Natural Gas	16500	HP	VOC	Oxidation catalyst.	11	LB/HR	EACH ENG. /HOURLY/EXCEPT DURING STARTUP-SHUTDOWN	0.7	G/HP-HR	EACH ENG/HOURLY	BACT-PSD	5/22/2019
OK-0153	OK	Rose Valley Plant	Compressor Engine (CAT G3606LE)	Natural Gas	1775	HP	VOC	Oxidation catalyst.	0.13	G/HP-HR	3-HR AVG	0.65	LB/HR		BACT-PSD	3/1/2013
PA-0297	PA	Kelly IMG Energy LLC/Kelly IMG Plant	Generators (Waukesha) #1 and #2	Natural Gas	3.11	MW	VOC		0.176	G/BHP-HR	PER ENGINE (INCLUDING FORMALDEHYDE)				OTHER CASE-BY-CASE	5/23/2013
PA-0301	PA	Carpenter Compressor Station	Three (3) 4SLB Engines - Caterpillar G3608 TA, 2370 BHP	Natural Gas	2370	BHP	VOC	Oxidation catalyst.	0.25	G/BHP-HR	NONMETHANE, NONETHANE HYDROCARBON AS PROPANE				N/A	3/31/2014
PA-0301	PA	Carpenter Compressor Station	One (1) 4SLB Engine, Caterpillar Model G3612 TA	Natural Gas	3550	BHP	VOC	Oxidation catalyst.	0.25	G-BHP-HR					N/A	3/31/2014
PA-0302	PA	Clermont Compressor Station	Seven (7) 4SRB SI Engines	Natural Gas			VOC	Non-selective catalytic reduction (NSCR) system.	0.2	G/BHP-HR					N/A	4/16/2014
TX-0680	TX	Sonora Gas Plant	Refrigeration Compressor Engine	Natural Gas	1183	HP	VOC	Oxidation catalyst.	0.245	G/HP-HR	1 HOUR				BACT-PSD	6/14/2013
TX-0680	TX	Sonora Gas Plant	Refrigeration Compressor Engine	Natural Gas	1380	HP	VOC	Oxidation catalyst.	0.245	G/HP-HR					BACT-PSD	6/14/2013
TX-0692	TX	Red Gate Power Plant	Twelve (12) Reciprocating Internal Combustion Engines	Natural Gas	18	MW	VOC	Oxidation catalyst.	0.3	G/HP-HR	1 HOUR				BACT-PSD	12/20/2013
WI-0314	WI	Wisconsin Public Service Corporation - Weston Plant	Reciprocating Internal Combustion Engines (P101-P107)	Natural Gas	152.3	MMBTU/HR	VOC	Good combustion practices; oxidation catalyst.	4.49	LB/HR					BACT-PSD	3/10/2022

Diesel Firewater Pumps - VOC

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0088	AK	Liquefaction Plant	Diesel Fire Pump Engine	Diesel	575	HP	VOC	Oxidation catalyst; limited operation; compliance with 40 CFR 60 Subpart IIII	0.19	G/HP-HR		500	HR/YR		BACT-PSD	7/7/2022
IN-0317	IN	Riverview Energy Corporation	Emergency Fire Pump (EU6008)	Diesel	750	HP	VOC	Compliance with 40 CFR 60 Subpart IIII; good combustion practices	4	G/KW-HR					BACT-PSD	6/11/2019
IN-0324	IN	Midwest Fertilizer Company LLC	Firewater Pump (EU015)	Diesel	500	HP	VOC	Good combustion practices.	0.141	G/HP-HR		500	HR/YR	TWELVE (12) CONSECUTIVE MONTH PERIOD	BACT-PSD	5/6/2022
KY-0110	KY	Nucor Steel Brandenburg	Emergency Fire Water Pump (EP 10-04)	Diesel	920	HP	VOC	Good combustion and operating practices							BACT-PSD	7/23/2020
LA-0276	LA	Baton Rouge Junction Facility	Fire Pump Engines (2 Units)	Diesel	700	HP	VOC	Compliance with 40 CFR 60 Subpart IIII							BACT-PSD	12/15/2016
*LA-0312	LA	St. James Methanol Plant	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	Diesel	650	HP	VOC	Compliance with 40 CFR 60 Subpart IIII	0.13	LB/HR					BACT-PSD	6/30/2017
*LA-0315	LA	G2G Plant	Fire Pump Diesel Engines 1 and 2	Diesel	751	HP	VOC	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ	0.34	LB/HR	HOURLY MAXIMUM	0.02	TPY	ANNUAL MAXIMUM	BACT-PSD	5/23/2014
LA-0331	LA	Calcasieu Pass LNG Project	Two (2) Firewater Pumps	Diesel	634	KW	VOC	Good combustion and operating practices; limited operation (50 hr/yr).	0.44	G/HP-HR					BACT-PSD	9/21/2018
LA-0364	LA	FG LA Complex	Emergency Fire Water Pumps	Diesel	550	HP	VOC	Compliance with 40 CFR 60 Subpart IIII; good combustion and operating practices							BACT-PSD	1/6/2020
*LA-0388	LA	LACC LLC US - Ethylene Plant	Firewater Pump Engines No. 1 and 2	Diesel	575	HP	VOC	Compliance with 40 CFR 60 Subpart IIII	0.32	LB/HR		0.01	TPY		BACT-PSD	2/25/2022
*NE-0064	NE	Norfolk Crush, LLC	Emergency Fire Water Pump Engine 1	Diesel	510	HP	VOC		0.62	G/HP-HR	3-HOUR OR TEST METHOD AVERAGE				BACT-PSD	11/21/2022
OH-0375	OH	Long Ridge Energy Generation LLC - Hannibal Power	Emergency Diesel Fire Pump Engine (P002)	Diesel	700	HP	VOC	Good combustion practices	4.97	LB/HR	NMHC + NOx.	0.25	TPY	NMHC + NOx.	BACT-PSD	11/7/2017
OK-0156	OK	Northstar Agri Industries Enid	Fire Pump Engine	Diesel	550	HP	VOC	Good combustion practices	0.35	LB/MMBTU	3-HOUR AVG				BACT-PSD	7/31/2013
PA-0311	PA	Moxie Freedom Generation Plant	Fire Pump Engine	Diesel			VOC	Good combustion and operating practices.	0.2	G/HP-HR		0.006	TPY	12-MONTH ROLLING BASIS	LAER	9/1/2015
SC-0193	SC	Mercedes Benz Vans, LLC	Emergency Generators and Fire Pump	No. 2 Fuel Oil	1500	HP	VOC	Compliance with 40 CFR 60 Subpart IIII; limited non-emergency operation (100 hrs/yr)			12 MONTH ROLLING SUM				BACT-PSD	4/15/2016
TX-0799	TX	Beaumont Terminal	Fire Pump Engines (2 Units)	Diesel			VOC	Oxidation catalyst; limited operation (100 hrs/yr); compliance with 40 CFR 60 Subpart IIII	0.0007	LB/HP-HR					BACT-PSD	6/8/2016
TX-0876	TX	Port Arthur Ethane Cracker Unit	Emergency Firewater Pumps	Ultra-low Sulfur Diesel			VOC	Compliance with Tier 3 exhaust emission standards in 40 CFR 89.112; limited non-emergency operation (100 hrs/yr)							BACT-PSD	2/6/2020
TX-0879	TX	Motiva Port Arthur Terminal	Emergency Firewater Engine	Ultra-low Sulfur Diesel			VOC	Compliance with 40 CFR 60 Subpart IIII; limited non-emergency operation (100 hrs/yr)	0.1	G/HP HR					BACT-PSD	2/19/2020
WI-0297	WI	Green Bay Packaging - Mill Division	Diesel-Fired Emergency Fire Pump (P36)	Diesel	510	HP	VOC	Compliance with 40 CFR 60 Subpart IIII; limited operation (200 hrs/yr)			CONSECUTIVE 12-MONTH				BACT-PSD	12/10/2019

Small Diesel Emergency Engines - VOC

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0085	AK	Gas Treatment Plant	Two (2) Emergency Diesel Generators	Ultra-low Sulfur Diesel	335	HP	VOC	Good combustion practices; use of ultra-low sulfur diesel; limited operation (500 hr/yr).	0.19	G/HP-HR	3-HOUR AVERAGE				BACT-PSD	8/13/2020
AR-0173	AR	Big River Steel LLC	Emergency Engines	Diesel			VOC	Good operating practices; limited operation; compliance with 40 CFR 60 Subpart IIII.	0.13	G/BHP-HR					BACT-PSD	1/31/2022
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Remotely Operated Vehicle Emergency Generator	Diesel	427	HP	VOC	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure.							BACT-PSD	9/16/2014
IN-0295	IN	Steel Dynamics, Inc. - Engineered Bar Products Division	Emergency Diesel Generators	Diesel	150	HP	VOC	Good combustion practices.	1.134	G/HP-HR		0.0025	LB/HP-HR		BACT-PSD	2/23/2018
IN-0295	IN	Steel Dynamics, Inc. - Engineered Bar Products Division	Emergency Diesel Generators	Diesel	250	HP	VOC	Good combustion practices.	1.134	G/HP-HR		0.0025	LB/HP-HR		BACT-PSD	2/23/2018
KY-0110	KY	Nucor Steel Brandenburg	EP 11-01 - Melt Shop Emergency Generator	Diesel	260	HP	VOC	Good combustion and operating practices.							BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-02 - Reheat Furnace Emergency Generator	Diesel	190	HP	VOC	Good combustion and operating practices.							BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-03 - Rolling Mill Emergency Generator	Diesel	440	HP	VOC	Good combustion and operating practices.							BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-04 - IT Emergency Generator	Diesel	190	HP	VOC	Good combustion and operating practices.							BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-05 - Radio Tower Emergency Generator	Diesel	61	HP	VOC	Good combustion and operating practices.							BACT-PSD	7/23/2020
LA-0314	LA	Indorama Lake Charles Facility	Diesel Emergency Generator Engine	Diesel	350	HP	VOC	Compliance with 40 CFR 63 Subpart ZZZZ.							BACT-PSD	8/3/2016
LA-0379	LA	Shintech Plaquemines Plant 1	PVC Emergency Combustion Equipment 2A and 2B	Diesel	300	HP	VOC	Compliance with 40 CFR 60 Subpart IIII.	0.19	G/KW-HR					BACT-PSD	5/4/2021
LA-0386	LA	LaSalle Bioenergy LLC	Generators and Firewater Pumps Engines	Diesel			VOC	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	5/5/2021
NJ-0085	NJ	Middlesex Energy Center, LLC	Emergency Generator	Ultra-low Sulfur Diesel			VOC	Use of ultra-low sulfur diesel; limited operation (100 hr/yr).	0.557	LB/HR					LAER	7/19/2016
OK-0175	OK	Wildhorse Terminal	Emergency Use Engine	Diesel	275	HP	VOC	Good combustion practices; certified to meet EPA Tier 3 engine standards in 40 CFR 60 Subpart IIII; limited operation (500 hr/yr).	3	GM/HP-HR					BACT-PSD	6/29/2017
OK-0176	OK	BPV Gathering and Marketing Cushing Station	Emergency Generator	Diesel	400	HP	VOC	Use of ultra-low sulfur diesel (0.015% or less by wt. sulfur).	217.24	TPY	12-MONTH				BACT-PSD	7/19/2017
OK-0177	OK	Cushing South Tank Farm	Emergency Use Engine	Diesel	450	HP	VOC	Good combustion practices; certified to meet EPA Tier 3 engine standards in 40 CFR 60 Subpart IIII; limited operation (500 hr/yr).	1	G/HP-HR					BACT-PSD	1/4/2018
OK-0181	OK	Wildhorse Terminal	Emergency Use Engine	Diesel	275	HP	VOC	Good combustion practices; certified to meet EPA Tier 3 engine standards in 40 CFR 60 Subpart IIII; limited operation (500 hr/yr).	3	G/HP-HR					BACT-PSD	9/11/2019
*PA-0326	PA	Shell Polymers Monaca Site	Emergency Generator - Parking Garage	Diesel			VOC	The use of certified engines; design of engines to include turbocharger and an intercooler/aftercooler; good combustion practices; proper operation and maintenance.	2.37	G/HP-HR					LAER	2/18/2021
*PA-0326	PA	Shell Polymers Monaca Site	Emergency Generator - Telecom Hut & Tower	Diesel			VOC	The use of certified engines; design of engines to include turbocharger and an intercooler/aftercooler; good combustion practices; proper operation and maintenance.	2.83	G/HP-HR					LAER	2/18/2021
TX-0706	TX	Natural Gas Fractionation	Emergency Engines	Ultra-low Sulfur Diesel			VOC		0.03	TPY					BACT-PSD	1/23/2014
TX-0799	TX	Beaumont Terminal	Emergency Engines	Diesel			VOC	Equipment specifications; good combustion practices; limited operation (100 hr/yr).	0.0025	LB/HP-HR					BACT-PSD	6/8/2016
TX-0864	TX	Equistar Chemicals Channelview Complex	Emergency Diesel Engine	Ultra-low Sulfur Diesel			VOC	Tier 4 exhaust emission standards specified at 40 CFR 1039.101(b); limited operation (100 hr/yr).							LAER	9/9/2019
TX-0886	TX	Mont Belvieu NGL Fractionation Unit	Emergency Diesel Engine	Ultra-low Sulfur Diesel			VOC	Limited operating hours; good combustion practices; meets EPA Tier 3 engine standards in 40 CFR 60 Subpart IIII.							LAER	3/31/2020
*WI-0261	WI	Enbridge Energy - Superior Terminal	EG7 - Diesel Emergency Electric Generator w/ Tank	Diesel	197	BHP	VOC	Certified to meet EPA Tier 3 engine standards in 40 CFR 60 Subpart IIII; good operating practices; limited operation (200 hr/yr).	3.75	G/HP-HR	NOX + NMHC HOURLY AVG., FOR EG7	3	G/HP-HR	NOX + NMHC FOR ENGINE CLASS (HOURLY AVG.)	BACT-PSD	6/12/2014
WI-0279	WI	Enbridge Energy Limited Partnership	EG8 - Diesel Emergency Generator	Diesel	125	KW	VOC	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	10/2/2017

Small Diesel Non-Emergency Engines - VOC

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0082	AK	Point Thomson Production Facility	Airstrip Generator Engine	Ultra-low Sulfur Diesel	490	HP	VOC		0.0025	LB/HP-HR					BACT-PSD	1/23/2015
AK-0082	AK	Point Thomson Production Facility	Agitator Generator Engine	Ultra-low Sulfur Diesel	98	HP	VOC		0.0025	LB/HP-HR					BACT-PSD	1/23/2015
AK-0082	AK	Point Thomson Production Facility	Incinerator Generator Engine	Ultra-low Sulfur Diesel	102	HP	VOC		0.0025	LB/HP-HR					BACT-PSD	1/23/2015
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Diesel Powered Forklift Engine	Diesel	30	HP	VOC	Good combustion practices.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Wireline Diesel Engines	Diesel			VOC	Good combustion practices.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Water Blasting Diesel Engine	Diesel	208	HP	VOC	Use of good combustion practices with turbocharger, aftercooler, and high injection pressure.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Well Evaluation Diesel Engine	Diesel	140	HP	VOC	Use of good combustion practices with turbocharger, aftercooler, and high injection pressure.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Fast Rescue Craft Diesel Engine	Diesel	230	HP	VOC	Good combustion practices.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Escape Capsule Diesel Engine	Diesel	39	HP	VOC	Use of good combustion practices with turbocharger, aftercooler, and high injection pressure.							BACT-PSD	9/16/2014
IL-0114	IL	Cronus Chemicals, LLC	Firewater Pump Engine	Distillate Fuel Oil	373	HP	VOC	Good combustion practices.	0.4	G/KW-HR					BACT-PSD	9/5/2014
KS-0036	KS	Westar Energy - Emporia Energy Center	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	No. 2 Fuel Oil	182	BHP	VOC	Efficient combustion practices and design technology.	0.77	G/BHP-HR					BACT-PSD	3/18/2013
LA-0309	LA	Benteler Steel Tube Facility	Firewater Pump Engines	Diesel	288	HP	VOC	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	6/4/2015
LA-0314	LA	Indorama Lake Charles Facility	Six (6) Diesel Firewater Pump Engines	Diesel	425	HP	VOC	Compliance with 40 CFR 63 subpart ZZZZ.							BACT-PSD	8/3/2016
LA-0316	LA	Cameron LNG Facility	Eight (8) Firewater Pump Engines	Diesel	460	HP	VOC	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	2/17/2017
LA-0386	LA	LaSalle Bioenergy LLC	Generators and Firewater Pumps Engines	Diesel			VOC	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	5/5/2021
*LA-0387	LA	Taylor Sawmill	Firewater Pump Engine	Diesel	274	HP	VOC	Compliance with 40 CFR 60 Subpart IIII.	0.02	TPY					BACT-PSD	4/12/2022
NY-0104	NY	CPV Valley Energy Center	Fire Pump	Ultra-low Sulfur Diesel			VOC	Good combustion practices.	0.3612	LB/MMBTU	1 HR				LAER	8/1/2013
PA-0286	PA	MOXIE Energy LLC/Patriot Generation Plant	Fire Pump Engine	Diesel	460	BHP	VOC		0.1	G/HP-HR		0.1	LB/HR		OTHER CASE-BY-CASE	1/31/2013
PA-0309	PA	Lackawanna Energy Center/Jessup	Fire Pump Engine	Ultra-low Sulfur Diesel	15	GAL/HR	VOC		0.12	G/HP-HR		0.002	TPY	12-MONTH ROLLING BASIS	LAER	12/23/2015
TX-0846	TX	Motor Vehicle Assembly Plant	Fire Pump Diesel Engine	No. 2 Diesel Fuel	214	kW	VOC	Meets EPA Tier 4 requirements in 40 CFR 60 Subpart IIII.	0.19	G/KW-HR	1 HR				BACT-PSD	9/23/2018
VA-0325	VA	Greensville Power Station	Diesel-Fired Water Pump	Ultra-low Sulfur Diesel	376	BHP	VOC	Good combustion practices.	3	G/HP-HR	1 HR				N/A	6/17/2016
WI-0302	WI	WPL - Riverside Energy Center	Diesel-Fired Fire Pump Engine (P04)	Diesel	290	HP	VOC	Good combustion practices.	0.26	LB/HR					BACT-PSD	2/28/2020

Marketing Terminal Fugitives - VOC

RBLCID	State	Facility	Process Name	Throughput	Throughput Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
TX-0656	TX	Gas to Gasoline Plant	Fugitive Components			VOC	LDAR 28 VHP.	500	PPM					BACT-PSD	5/16/2014
TX-0731	TX	Corpus Christi Terminal Condensate Splitter	Petroleum Refining Equipment Leaks/Fugitive Emissions	100000	BBL/DAY	VOC	Quarterly instrumental monitoring using a method 21 gas analyzer for all valves, pump seals, compressor seals, and agitator seals with a leak definition of 500 parts per million volume (ppmv) for valves and 2,000 ppmv for pump, compressor and agitator seals. Leaking components must be repaired within 15 days of detection of the leak.	36.6	TPY					BACT-PSD	4/10/2015
TX-0756	TX	CCI Corpus Christi Condensate Splitter Facility	Fugitive Components			VOC	Fugitive Leak Detection and Repair (LDAR) program that requires quarterly monitoring of valves with a leak definition of 500 ppmv. Quarterly monitoring of pump and compressor seals with a leak definition of 2,000 ppmv.	500	PPMV	VALVES	2000	PPMV	PUMP AND COMPRESSER SEALS	BACT-PSD	6/19/2015
TX-0765	TX	Sunoco Marine Vessel Loading Operations	Petroleum Refining Equipment Leaks/Fugitive Emissions	100	MMBBL/YR	VOC	Quarterly instrumental monitoring (28VHP) using a method 21 gas analyzer for all valves, pump seals, compressor seals, and agitator seals with a leak definition of 500 ppmv for valves and 2,000 ppmv for pump, compressor and agitator seals. Leaking components must be repaired within 15 days of detection of the leak.	10.13	TPY					BACT-PSD	9/18/2015
TX-0800	TX	Corpus Crude Oil Terminal	Fugitives			VOC	Uncontrolled VOC fugitive emissions are estimated to be less than 10 TPY. Fugitive components are monitored and minimized via an audio, olfactory, and visual (AVO) inspection once every four hours.	0.41	TPY					BACT-PSD	6/22/2016
TX-0808	TX	Houston Fuel Oil Terminal	Fugitives at Marine Loading			VOC	Monitoring under 28 LAER (Lowest Available Emission Rate) Leak Detection and Repair program.	0.04	TPY					LAER	9/2/2016
TX-0818	TX	Fuel Oil Terminal	Marine Loading Fugitives			VOC	Monitoring under 28 LAER (Lowest Available Emission Rate) Leak Detection and Repair program.	0.16	TPY					LAER	4/26/2017
TX-0825	TX	Pasadena Terminal	Uncaptured Marine Loading Fugitives From Ships			VOC	A minimum of three vessels per year for five years will undergo VOC collection efficiency testing to ensure compliance with 99.89% loading vapor collection efficiency of inerted ocean-going marine vessels	23.66	TPY					LAER	7/14/2017
TX-0852	TX	Corpus Christi Waterfront Terminal	Fugitive Components			VOC	28 LAER.							BACT-PSD	1/2/2019
TX-0855	TX	Buckeye South Texas Gateway Terminal	Fugitives			VOC	28 VHP, 28 PI LDAR.							BACT-PSD	3/13/2019
TX-0872	TX	Condensate Splitter Facility	Fugitives (Routine)			VOC	28VHP; Leak-less connectors.	15.63	LB/HR					BACT-PSD	10/31/2019
TX-0879	TX	Motiva Port Arthur Terminal	Fugitives			VOC	28PET leak detection and repair program; Monthly Audio/Visual/Olfactory (AVO) inspection requirements							LAER	2/19/2020
TX-0879	TX	Motiva Port Arthur Terminal	Process Fugitives			VOC	28VHP leak detection and repair program; 97% credit for valves, 85% for pumps and compressors.							BACT-PSD	2/19/2020
TX-0887	TX	Midland Plains Marketing Terminal	Fugitives			VOC	The site-wide fugitive emissions are less than 10 tpy uncontrolled VOC emissions; LADR program and emission reduction credit is not applied.							BACT-PSD	4/7/2020

Petroleum Storage in Fixed Roof Tanks - VOC

RBLCID	State	Facility	Process Name	Throughput	Throughput Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
TX-0656	TX	Gas to Gasoline Plant	Three (3) Fixed Roof Tanks	800000	GAL/YR	VOC	Water scrubber.	1.65	TPY					BACT-PSD	5/16/2014
TX-0731	TX	Corpus Christi Terminal Condensate Splitter	Petroleum Liquids Storage in Fixed Roof Tanks	3.4	MMBBL/YR	VOC	Temperature reduced to maintain volatile organic compound (VOC) vapor pressure < 0.5 pounds per square inch actual (psia) at all times.	15.78	TPY					BACT-PSD	4/10/2015
TX-0756	TX	CCI Corpus Christi Condensate Splitter Facility	Storage Tanks (TK-110, TK-111, TK-112)	57960	GAL/HR	VOC	Tanks are required to be painted white and be equipped with submerged fill pipes.	3.07	LB/HR		2.63	TPY		BACT-PSD	6/19/2015
TX-0756	TX	CCI Corpus Christi Condensate Splitter Facility	Storage Tanks (TK-113, TK-114, and TK-115)	47000000	GAL/YR	VOC	Tanks are required to be painted white and be equipped with submerged fill pipes.	0.85	LB/HR		1.15	TPY		BACT-PSD	6/19/2015
TX-0772	TX	Port of Beaumont Petroleum Transload Terminal (PBPTT)	Petroleum Liquids Storage in Fixed Roof Tanks	47.62	BBL/YR	VOC	Tank uses submerged fill and is aluminum in color.	0.01	TPY					BACT-PSD	11/6/2015
TX-0808	TX	Houston Fuel Oil Terminal	Storage Tank			VOC	Tanks are required to be painted white and be equipped with insulated, submerged fill pipes.	0.1	TPY					LAER	9/2/2016
TX-0825	TX	Pasadena Terminal	Horizontal Fixed Roof Storage Tanks			VOC	Tanks painted white with submerged fill pipes.	0.37	TPY					LAER	7/14/2017
TX-0825	TX	Pasadena Terminal	Horizontal Fixed Roof Storage Tanks - Maintenance, Startup, and Shutdown			VOC	Degassing and refilling losses will be controlled by vapor combustor with a 99.5% destruction efficiency.	26.28	TPY					LAER	7/14/2017

RBLC - NO_X

- Process Type 17.130 – Large Natural Gas Engines
- Process Type 17.110 – Large Emergency Diesel Engines
- Process Type 17.210 – Small Emergency Diesel Engines
- Process Type 17.210 – Small Non-Emergency Diesel Engines

Large Natural Gas Generators - NO_x

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
CA-1240	CA	Gold Coast Packing	Internal Combustion Engine	Natural Gas	881	BHP	NO_x	Selective catalytic reduction (SCR) system - urea injection.	5	PPMVD	@15% O2				OTHER CASE-BY-CASE	3/17/2017
KS-0030	KS	Mid-Kansas Electric Company, LLC - Rubart Station	Spark Ignition RICE Electricity Generating Units (EGUs)	Natural Gas	10	MW	NO_x		2.13	LB/HR	1-HR AVE. PERIOD, EXCEPT DURING STARTUP	14.41	LB/HR	1-HR AVE. PERIOD, DURING STARTUP	BACT-PSD	3/31/2016
KS-0035	KS	Lacey Randall Generation Facility, LLC	Spark Ignition 4SLB RICE Electric Generating Units (EGUs)	Natural Gas	12526	BHP	NO_x	SCR system; oxidation catalyst.	1.45	LB/HR	1-HR AVERAGING PERIOD, EXCLUDING STARTUP	11.97	LB/HR	1-HR AVERAGING PERIOD, DURING STARTUP	BACT-PSD	1/24/2014
LA-0292	LA	Holbrook Compressor Station	Waukesha 16V-275GL Compressor Engines Nos. 1-12	Natural Gas	5000	HP	NO_x	Lean-burn combustion; use of natural gas as fuel; good equipment design and combustion practices.	4.96	LB/HR	HOURLY MAXIMUM	21.73	TPY	ANNUAL MAXIMUM	BACT-PSD	1/22/2016
MI-0440	MI	Michigan State University	Flexible Group (FG) Engines - 4 RICE	Natural Gas	16500	HP	NO_x	SCR system.	0.5	G/HP-HR	HOURLY EXCEPT DURING STARTUP/ SHUTDOWN	1	G/HP-HR	HOURLY	BACT-PSD	5/22/2019
OK-0153	OK	Rose Valley Plant	Compressor Engine (CAT G3606LE)	Natural Gas	1775	HP	NO_x		0.5	G/HP-HR	3-HR AVG	1.96	LB/HR		BACT-PSD	3/1/2013
PA-0297	PA	Kelly IMG Energy LLC/Kelly IMG Plant	Generators (Waukesha) #1 and #2	Natural Gas	3.11	MW	NO_x		0.5	G/BHP-HR	PER ENGINE				OTHER CASE-BY-CASE	5/23/2013
PA-0301	PA	Carpenter Compressor Station	Three (3) 4SLB Engines - Caterpillar G3608 TA, 2370 BHP	Natural Gas	2370	BHP	NO_x		0.5	G/BHP-HR					N/A	3/31/2014
PA-0301	PA	Carpenter Compressor Station	One (1) 4SLB Engine, Caterpillar Model G3612 TA	Natural Gas	3550	BHP	NO_x		0.5	G/BHP-HR					N/A	3/31/2014
PA-0302	PA	Clermont Compressor Station	Seven (7) 4SRB SI Engines	Natural Gas			NO_x	Non-selective catalytic reduction (NSCR) system.	0.2	G/BHP-HR					N/A	4/16/2014
TX-0680	TX	Sonora Gas Plant	Refrigeration Compressor Engine	Natural Gas	1183	HP	NO_x	Ultra-lean burn technology.	0.5	G/HP-HR	1 HOUR				BACT-PSD	6/14/2013
TX-0680	TX	Sonora Gas Plant	Refrigeration Compressor Engine	Natural Gas	1380	HP	NO_x	Ultra-lean burn technology.	0.5	G/HP-HR	1 HOUR				BACT-PSD	6/14/2013
TX-0692	TX	Red Gate Power Plant	Twelve (12) Reciprocating Internal Combustion Engines	Natural Gas	18	MW	NO_x	SCR system.	0.084	G/HP-HR	1 HOUR				BACT-PSD	12/20/2013

Diesel Firewater Pumps - NO_x

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0088	AK	Liquefaction Plant	Diesel Fire Pump Engine	Diesel	575	HP	NO_x	Good combustion practices; limited operation; compliance with 40 CFR 60 Subpart IIII.	3.6	G/HP-HR		500	HR/YR		BACT-PSD	7/7/2022
IN-0317	IN	Riverview Energy Corporation	Emergency Fire Pump (EU6008)	Diesel	750	HP	NO_x	Compliance with 40 CFR 60 Subpart IIII.	4	G/KW-HR	COMBINED NOX + NMHC LIMIT				BACT-PSD	6/11/2019
IN-0324	IN	Midwest Fertilizer Company LLC	Firewater Pump (EU015)	Diesel	500	HP	NO_x	Good combustion practices.	2.83	G/HP-HR		500	HR/YR	CONSECUTIVE MONTH PERIOD	BACT-PSD	5/6/2022
KY-0110	KY	Nucor Steel Brandenburg	Emergency Fire Water Pump (EP 10-04)	Diesel	920	HP	NO_x	Good combustion and operating practices.	4.77	G/HP-HR	NMHC + NOx.				BACT-PSD	7/23/2020
*LA-0312	LA	St. James Methanol Plant	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	Diesel	650	HP	NO_x	Compliance with 40 CFR 60 Subpart IIII.	6.6	LB/HR					BACT-PSD	6/30/2017
*LA-0315	LA	G2G Plant	Fire Pump Diesel Engines 1 and 2	Diesel	751	HP	NO_x	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.	4.6	LB/HR	HOURLY MAXIMUM	0.23	TPY	ANNUAL MAXIMUM	BACT-PSD	5/23/2014
LA-0317	LA	Methanex - Geismar Methanol Plant	Firewater Pump Engines	Diesel	896	HP	NO_x	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.							BACT-PSD	12/22/2016
LA-0323	LA	Monsanto Luling Plant	Fire Water Diesel Pumps No. 3 and 4	Diesel	600	HP	NO_x	Good operating practices; limited operation; compliance with 40 CFR 60 Subpart IIII							BACT-PSD	1/9/2017
LA-0331	LA	Calcasieu Pass LNG Project	Two (2) Firewater Pumps	Diesel	634	HP	NO_x	Good combustion and operating practices; limited operation (50 hr/yr).	3.1	G/HP-HR					BACT-PSD	9/21/2018
LA-0364	LA	FG LA Complex	Emergency Fire Water Pumps	Diesel	550	HP	NO_x	Compliance with CFR 60 Subpart IIII; good combustion and operating practices.							BACT-PSD	1/6/2020
MI-0448	MI	Grayling Particleboard	Diesel Fire Pump Engine	Diesel	400	KW	NO_x	Certified engines; limited operation.	3.53	LB/HR	HOURLY				BACT-PSD	12/18/2020
*NE-0064	NE	Norfolk Crush, LLC	Emergency Fire Water Pump Engine 1	Diesel	510	HP	NO_x		2.38	G/HP-HR	METHOD AVERAGE				BACT-PSD	11/21/2022
OH-0375	OH	Generation LLC - Hannibal Power	Emergency Diesel Fire Pump Engine (P002)	Diesel	700	HP	NO_x	Good combustion design.	4.97	LB/HR	NMHC + NOx.	0.25	TPY	NMHC + NOx.	BACT-PSD	11/7/2017
OH-0383	OH	Petmin USA Incorporated	Diesel-fired Emergency Fire Pumps (P009 and P010)	Diesel	3131	HP	NO_x	Tier IV NSPS standards certified by engine manufacturer.							BACT-PSD	7/17/2020
PA-0311	PA	Moxie Freedom Generation Plant	Fire Pump Engine	Ultra-low Sulfur Diesel			NO_x	Good combustion and operating practices.	3	G/HP-HR		0.08	TPY	12-MONTH ROLLING BASIS	LAER	9/1/2015
TX-0876	TX	Port Arthur Ethane Cracker Unit	Emergency Firewater Pumps	Ultra-low Sulfur Diesel			NO_x	Tier 3 exhaust emission standards specified in 40 CFR 89.112, limited operation (100 hr/yr).							BACT-PSD	2/6/2020
TX-0879	TX	Motiva Port Arthur Terminal	Emergency Firewater Engine	Ultra-low Sulfur Diesel			NO_x	Compliance with 40 CFR Part 60 Subpart IIII; limited operation (100 hr/yr).							BACT-PSD	2/19/2020

Small Diesel Emergency Engines - NOx

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Case-by-Case Basis	Permit Date
AK-0085	AK	Gas Treatment Plant	Two (2) Emergency Diesel Generators	Ultra-low Sulfur Diesel	335	HP	NO_x	Good combustion practices; use of ultra-low sulfur diesel; limited operation (500 hr/yr).	3.6	G/HP-HR	3-HOUR AVERAGE			BACT-PSD	8/13/2020
AR-0173	AR	Big River Steel LLC	Emergency Engines	Diesel			NO_x	Good operating practices; limited operation; compliance with 40 CFR 60 Subpart IIII.	3.9	G/BHP-HR				BACT-PSD	1/31/2022
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Remotely Operated Vehicle Emergency Generator	Diesel	427	HP	NO_x	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure.						BACT-PSD	9/16/2014
IN-0295	IN	Steel Dynamics, Inc. - Engineered Bar Products Division	Emergency Diesel Generators	Diesel	150	HP	NO_x	Good combustion practices.	14.06	G/HP-HR		0.031	LB/HP-HR	BACT-PSD	2/23/2018
IN-0295	IN	Steel Dynamics, Inc. - Engineered Bar Products Division	Emergency Diesel Generators	Diesel	250	HP	NO_x	Good combustion practices.	9.2	G/KW-HR		6.86	G/HP-HR	BACT-PSD	2/23/2018
KY-0110	KY	Nucor Steel Brandenburg	EP 11-01 - Melt Shop Emergency Generator	Diesel	260	HP	NO_x	Good combustion and operating practices.	2.98	G/HP-HR	NMHC + NOX			BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-02 - Reheat Furnace Emergency Generator	Diesel	190	HP	NO_x	Good combustion and operating practices.	2.98	G/HP-HR	NMHC + NOX			BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-03 - Rolling Mill Emergency Generator	Diesel	440	HP	NO_x	Good combustion and operating practices.	2.98	G/HP-HR	NMHC + NOX			BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-04 - IT Emergency Generator	Diesel	190	HP	NO_x	Good combustion and operating practices.	2.98	G/HP-HR	NMHC + NOX			BACT-PSD	7/23/2020
KY-0115	KY	Nucor Steel Gallatin, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	Diesel	350	HP	NO_x	Good combustion and operating practices.						BACT-PSD	4/19/2021
LA-0314	LA	Indorama Lake Charles Facility	Diesel Emergency Generator Engine	Diesel	350	HP	NO_x	Compliance with 40 CFR 63 Subpart ZZZZ.						BACT-PSD	8/3/2016
LA-0323	LA	Monsanto Luling Plant	Standby Generator No. 9 Engine	Diesel	400	HP	NO_x	Limited operation; compliance with 40 CFR 60 Subpart IIII.						BACT-PSD	1/9/2017
LA-0379	LA	Shintech Plaquemines Plant 1	PVC Emergency Combustion Equipment A	Diesel	450	HP	NO_x	Good combustion practices/gaseous fuel burning.	6.9	G/HP-HR				BACT-PSD	5/4/2021
LA-0379	LA	Shintech Plaquemines Plant 1	PVC Emergency Combustion Equipment 2A and 2B	Diesel	300	HP	NO_x	Compliance with 40 CFR 60 Subpart IIII.	0.4	G/KW-HR				BACT-PSD	5/4/2021
*LA-0381	LA	EUEG-5 Unit - Geismar Plant	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	Diesel			NO_x	Compliance with 40 CFR 60 Subpart IIII.						BACT-PSD	12/12/2019
LA-0386	LA	LaSalle Bioenergy LLC	Generators and Firewater Pumps Engines	Diesel			NO_x	Compliance with 40 CFR 60 Subpart IIII.						BACT-PSD	5/5/2021
NJ-0085	NJ	Middlesex Energy Center, LLC	Emergency Generator	Ultra-low Sulfur Diesel			NO_x	Use of ultra-low sulfur diesel; limited operation (100 hr/yr).	20.6	LB/H				LAER	7/19/2016
*PA-0326	PA	Shell Polymers Monaca Site	Emergency Generator - Parking Garage	Diesel			NO_x	The use of certified engines; design of engines to include turbocharger and an intercooler/aftercooler; good combustion practices; proper operation and maintenance.	2.37	G/HP-HR				LAER	2/18/2021
*PA-0326	PA	Shell Polymers Monaca Site	Emergency Generator - Telecom Hut & Tower	Diesel			NO_x	The use of certified engines; design of engines to include turbocharger and an intercooler/aftercooler; good combustion practices; proper operation and maintenance.	2.83	G/HP-HR				LAER	2/18/2021
TX-0706	TX	Natural Gas Fractionation	Emergency Engines	Ultra-low Sulfur Diesel			NO_x		0.33	TPY				BACT-PSD	1/23/2014
TX-0864	TX	Equistar Chemicals Channelview Complex	Emergency Diesel Engine	Ultra-low Sulfur Diesel			NO_x	Tier 4 exhaust emission standards specified at 40 CFR 1039.101(b); limited operation (100 hr/yr).						BACT-PSD	9/9/2019
TX-0886	TX	Mont Belvieu NGL Fractionation Unit	Emergency Diesel Engine	Ultra-low Sulfur Diesel			NO_x	Limited operating hours; good combustion practices; meets EPA Tier 3 engine standards in 40 CFR 60 Subpart IIII.						LAER	3/31/2020
WI-0271	WI	Kohler Co-Metals Processing Complex	Diesel Powered Emergency Generator	Distillate Fuel	465	HP	NO_x	Limited operation (200 hr/yr).	5.9	LB/HR				BACT-PSD	6/5/2015
WI-0291	WI	Graymont Western Lime - Eden	P04 Emergency Diesel Generator	Diesel	35	KW	NO_x	Good combustion practices.	4.7	G/KW-HR				BACT-PSD	1/28/2019

Small Diesel Non-Emergency Engines - NO_x

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0082	AK	Point Thomson Production Facility	Airstrip Generator Engine	Ultra-low Sulfur Diesel	490	HP	NO_x		4.8	G/HP-HR					BACT-PSD	1/23/2015
AK-0082	AK	Point Thomson Production Facility	Agitator Generator Engine	Ultra-low Sulfur Diesel	98	HP	NO_x		5.6	G/HP-HR					BACT-PSD	1/23/2015
AK-0084	AK	Donlin Gold Project	Fire Pump Diesel Internal Combustion Engines	Diesel	252	HP	NO_x	Good combustion practices.	3.7	G/KW-HR	3-HOUR AVERAGE				BACT-PSD	6/30/2017
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Diesel Powered Forklift Engine	Diesel	30	HP	NO_x	Good combustion practices.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Wireline Diesel Engines	Diesel			NO_x	Use of good combustion practices with turbocharger, aftercooler, and high injection pressure.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Water Blasting Diesel Engine	Diesel	208	HP	NO_x	Use of good combustion practices with turbocharger, aftercooler, and high injection pressure.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Well Evaluation Diesel Engine	Diesel	140	HP	NO_x	Good combustion practices.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Fast Rescue Craft Diesel Engine	Diesel	230	HP	NO_x	Use of good combustion practices with turbocharger, aftercooler, and high injection pressure.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Escape Capsule Diesel Engine	Diesel	39	HP	NO_x	Good combustion practices.							BACT-PSD	9/16/2014
IL-0114	IL	Cronus Chemicals, LLC	Firewater Pump Engine	Distillate Fuel Oil	373	HP	NO_x	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	3.5	G/KW-HR					BACT-PSD	9/5/2014
IL-0129	IL	CPV Three Rivers Energy Center	Firewater Pump Engine	Ultra-low Sulfur Diesel	422	HP	NO_x								LAER	7/30/2018
IL-0130	IL	Jackson Energy Center	Firewater Pump Engine	Ultra-low Sulfur Diesel	420	HP	NO_x		4	G/KW-HR					LAER	12/31/2018
IL-0133	IL	Lincoln Land Energy Center	Fire Water Pump Engine	Ultra-low Sulfur Diesel	320	HP	NO_x		4	G/KW-HR					BACT-PSD	7/29/2022
KS-0036	KS	Westar Energy - Emporia Energy Center	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	No. 2 Fuel Oil	182	BHP	NO_x	Efficient combustion practices and design technology.	2	LB/HR	AT FULL LOAD				BACT-PSD	3/18/2013
LA-0308	LA	Morgan City Power Plant	Diesel Fired Pump Engine	Diesel	380	HP	NO_x	Good combustion and maintenance practices; compliance with NSPS 40 CFR 60 Subpart IIII.	2.92	LB/HR	HOURLY MAXIMUM	0.12	TPY	ANNUAL MAXIMUM	BACT-PSD	9/26/2013
LA-0309	LA	Benteler Steel Tube Facility	Firewater Pump Engines	Diesel	288	HP	NO_x	Compliance with 40 CFR 60 Subpart IIII.	3	G/BHP-HR					BACT-PSD	6/4/2015
LA-0314	LA	Indorama Lake Charles Facility	Six (6) Diesel Firewater Pump Engines	Diesel	425	HP	NO_x	Compliance with 40 CFR 63 Subpart ZZZZ.							BACT-PSD	8/3/2016
LA-0345	LA	Direct Reduced Iron Facility	Internal Combustion Engines	Diesel			NO_x	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	6/13/2019
LA-0386	LA	LaSalle Bioenergy LLC	Generators and Firewater Pumps Engines	Diesel			NO_x	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	5/5/2021
MD-0046	MD	Keys Energy Center	Diesel-Fired Fire Pump Engine	Ultra-low Sulfur Diesel	300	HP	NO_x	Use of ultra-low sulfur diesel; good combustion practices.	4	G/KW-HR					BACT-PSD	10/31/2014
OH-0379	OH	Petmin USA Incorporated	Black Start Generator (P007)	Diesel	158	HP	NO_x	Meets EPA Tier 4 requirements in 40 CFR 60 Subpart IIII.	0.104	LB/HR		0.0052	TPY		BACT-PSD	2/6/2019
PA-0286	PA	Moxie Energy LLC/Patriot Generation Plant	Fire Pump Engine	Diesel	460	BHP	NO_x		2.6	G/HP-HR	EXPRESSED AS NO2	2.6	LB/HR		OTHER CASE-BY-CASE	1/31/2013
PA-0309	PA	Lackawanna Energy Center/Jessup	Fire Pump Engine	Ultra-low Sulfur Diesel	15	GAL/HR	NO_x		3	G/HP-HR		0.05	TPY	12-MONTH ROLLING BASIS	LAER	12/23/2015
TX-0846	TX	Motor Vehicle Assembly Plant	Fire Pump Diesel Engine	No. 2 Diesel Fuel	214	KW	NO_x	Meets EPA Tier 4 requirements in 40 CFR 60 Subpart IIII.	0.4	G/KW-HR					BACT-PSD	9/23/2018
VA-0325	VA	Greensville Power Station	Diesel-Fired Water Pump	Ultra-low Sulfur Diesel	376	BHP	NO_x	Good combustion and maintenance practices.							N/A	6/17/2016
WI-0302	WI	WPL - Riverside Energy Center	Diesel-Fired Fire Pump Engine (P04)	Diesel	290	HP	NO_x	Use of ultra-low sulfur diesel.	3.64	LB/HR					BACT-PSD	2/28/2020

RBLC – CO

- Process Type 17.130 – Large Natural Gas Engines
- Process Type 17.110 – Large Emergency Diesel Engines
- Process Type 17.210 – Small Emergency Diesel Engines
- Process Type 17.210 – Small Non-Emergency Diesel Engines

Large Natural Gas Generators - CO

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
CA-1240	CA	Gold Coast Packing	Internal Combustion Engine	Natural Gas	881	BHP	CO	Oxidation catalyst.	54	PPMVD	@15% O2				OTHER CASE-BY-CASE	3/17/2017
KS-0030	KS	Mid-Kansas Electric Company, LLC - Rubart Station	Spark Ignition RICE Electricity Generating Units (EGUs)	Natural Gas	10	MW	CO		3.86	LB/HR	1-HR AVE. PERIOD, EXCEPT DURING STARTUP	39.23	LB/HR	1-HR AVE. PERIOD, DURING STARTUP	BACT-PSD	3/31/2016
KS-0035	KS	Lacey Randall Generation Facility, LLC	Spark Ignition 4SLB RICE Electric Generating Units (EGUs)	Natural Gas	12526	BHP	CO	Selective catalytic reduction (SCR) system; oxidation system.	2.67	LB/HR	1-HR AVERAGING, EXCLUDING STARTUP	9.72	LB/HR	1-HR AVERAGING, DURING STARTUP	BACT-PSD	1/24/2014
OK-0153	OK	Rose Valley Plant	Compressor Engine (CAT G3606LE)	Natural Gas	1775	HP	CO	Oxidation catalyst.	0.36	G/HP-HR	3-HR AVG	1.39	LB/HR		BACT-PSD	3/1/2013
PA-0297	PA	Kelly IMG Energy LLC/Kelly IMG Plant	Generators (Waukesha) #1 and #2	Natural Gas	3.11	MW	CO	Oxidation catalyst.	0.08	G/BHP-HR	PER ENGINE				OTHER CASE-BY-CASE	5/23/2013
PA-0301	PA	Carpenter Compressor Station	Three (3) 4SLB Engines - Caterpillar G3608 TA, 2370 BHP	Natural Gas	2370	BHP	CO	Oxidation catalyst.	47	PPMVD	AT 15% O2 OR 93% REDUCTION				N/A	3/31/2014
PA-0301	PA	Carpenter Compressor Station	One (1) 4SLB Engine, Caterpillar Model G3612 TA	Natural Gas	3550	BHP	CO	Oxidation catalyst.	47	PPMVD	AT 15% O2 OR 93% REDUCTION				N/A	3/31/2014
PA-0302	PA	Clermont Compressor Station	Seven (7) 4SRB SI Engines	Natural Gas			CO	Non-selective catalytic reduction (NSCR) system.	0.3	G/BHP-HR					N/A	4/16/2014
TX-0680	TX	Sonora Gas Plant	Refrigeration Compressor Engine	Natural Gas	1183	HP	CO	Oxidation catalyst.	0.252	G/HP-HR	1 HOUR				BACT-PSD	6/14/2013
TX-0680	TX	Sonora Gas Plant	Refrigeration Compressor Engine	Natural Gas	1380	HP	CO	Oxidation catalyst.	0.252	G/HP-HR	1 HOUR				BACT-PSD	6/14/2013
TX-0692	TX	Red Gate Power Plant	Twelve (12) Reciprocating Internal Combustion Engines	Natural Gas	18	MW	CO	Oxidation catalyst.	0.3	G/HP-HR	1 HOUR				BACT-PSD	12/20/2013
WI-0314	WI	Wisconsin Public Service Corporation - Weston Plant	Reciprocating Internal Combustion Engines (P101-P107)	Natural Gas	152.3	MMBTU/HR	CO	Good combustion practices; oxidation catalyst.	4.43	LB/HR		14	PPMVD	15% O2, 1-HR AVG. BASIS	BACT-PSD	3/10/2022

Diesel Firewater Pumps - CO

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0088	AK	Liquefaction Plant	Diesel Fire Pump Engine	Diesel	575	HP	CO	Oxidation catalyst; limited operation; compliance with 40 CFR 60 Subpart IIII.	3.3	G/HP-HR		500	HR/YR		BACT-PSD	7/7/2022
IN-0317	IN	Riverview Energy Corporation	Emergency Fire Pump (EU6008)	Diesel	750	HP	CO	Compliance with 40 CFR 60 Subpart IIII.	3.5	G/KW-HR					BACT-PSD	6/11/2019
IN-0324	IN	Midwest Fertilizer Company LLC	Firewater Pump (EU015)	Diesel	500	HP	CO	Good combustion practices.	2.6	G/HP-HR		500	HR/YR	TWELVE (12) CONSECUTIVE MONTH PERIOD	BACT-PSD	5/6/2022
KY-0110	KY	Nucor Steel Brandenburg	Emergency Fire Water Pump (EP 10-04)	Diesel	920	HP	CO	Good combustion and operating practices.	2.61	G/HP-HR					BACT-PSD	7/23/2020
*LA-0312	LA	St. James Methanol Plant	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	Diesel	650	HP	CO	Compliance with 40 CFR 60 Subpart IIII.	0.9	LB/HR					BACT-PSD	6/30/2017
*LA-0315	LA	G2G Plant	Fire Pump Diesel Engines 1 and 2	Diesel	751	HP	CO	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.	4.32	LB/HR	HOURLY MAXIMUM	0.22	TPY	ANNUAL MAXIMUM	BACT-PSD	5/23/2014
LA-0317	LA	Methanex - Geismar Methanol Plant	Firewater Pump Engines	Diesel	896	HP	CO	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.							BACT-PSD	12/22/2016
LA-0323	LA	Monsanto Luling Plant	Fire Water Diesel Pumps No. 3 and 4	Diesel	600	HP	CO	Good operating practices; limited operation; compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	1/9/2017
LA-0331	LA	Calcasieu Pass LNG Project	Two (2) Firewater Pumps	Diesel	634	KW	CO	Good combustion and operating practices; limited operation (50 hr/yr).	3.7	G/HP-HR					BACT-PSD	9/21/2018
LA-0364	LA	FG LA Complex	Emergency Fire Water Pumps	Diesel	550	HP	CO	Compliance with 40 CFR 60 Subpart IIII; good combustion and operating practices.							BACT-PSD	1/6/2020
*LA-0388	LA	LACC LLC US - Ethylene Plant	Firewater Pump Engine No. 1 and 2	Diesel	575	HP	CO	Compliance with 40 CFR 60 Subpart IIII.	3.97	LB/HR		0.17	TPY		BACT-PSD	2/25/2022
MI-0448	MI	Grayling Particleboard	Diesel Fire Pump Engine	Diesel	400	KW	CO	Good combustion practices.	3.5	G/KW-HR	HOURLY	3.09	LB/HR	HOURLY	BACT-PSD	12/18/2020
OH-0375	OH	Generation LLC - Hannibal Power	Emergency Diesel Fire Pump Engine (P002)	Diesel	700	HP	CO	Good combustion design.	4.01	LB/HR		0.2	TPY	PER ROLLING 12 MONTH PERIOD	BACT-PSD	11/7/2017
OH-0383	OH	Petmin USA Incorporated	Diesel-fired Emergency Fire Pumps (P009 and P010)	Diesel	3131	HP	CO	Tier IV NSPS standards certified by engine manufacturer.							BACT-PSD	7/17/2020
PA-0311	PA	Moxie Freedom Generation Plant	Fire Pump Engine	Diesel			CO	Good combustion and operating practices.	1	G/HP-HR		0.28	TPY	12-MONTH ROLLING BASIS	BACT-PSD	9/1/2015
TX-0799	TX	Beaumont Terminal	Fire Pump Engines	Diesel			CO	Equipment specifications and good combustion practices; limited operation (100 hr/yr).	0.0055	LB/HP-HR					BACT-PSD	6/8/2016
TX-0876	TX	Port Arthur Ethane Cracker Unit	Emergency Firewater Pumps	Ultra-low Sulfur Diesel			CO	Compliance with Tier 3 exhaust emission standards in 40 CFR 89.112; limited non-emergency operation (100 hrs/yr)							BACT-PSD	2/6/2020

Small Diesel Emergency Engines - CO

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0085	AK	Gas Treatment Plant	Two (2) Emergency Diesel Generators	Ultra-low Sulfur Diesel	335	HP	CO	Good combustion practices; use of ultra-low sulfur diesel; limited operation (500 hr/yr).	3.3	G/HP-HR	3-HOUR AVERAGE				BACT-PSD	8/13/2020
AR-0173	AR	Big River Steel LLC	Emergency Engines	Diesel			CO	Good operating practices; limited operation; compliance with 40 CFR 60 Subpart IIII.	0.9	G/BHP-HR					BACT-PSD	1/31/2022
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Remotely Operated Vehicle Emergency Generator	Diesel	427	HP	CO	Use of good combustion practices based on the most recent manufacturer's specifications issued for engines and with turbocharger, aftercooler, and high injection pressure.							BACT-PSD	9/16/2014
IN-0295	IN	Steel Dynamics, Inc. - Engineered Bar Products Division	Emergency Diesel Generators	Diesel	150	HP	CO	Good combustion practices.	3.08	G/KW-HR		0.0067	LB/HP-HR		BACT-PSD	2/23/2018
IN-0295	IN	Steel Dynamics, Inc. - Engineered Bar Products Division	Emergency Diesel Generators	Diesel	250	HP	CO	Good combustion practices.	3.08	G/HP-HR		0.0067	LB/HP-HR		BACT-PSD	2/23/2018
KY-0110	KY	Nucor Steel Brandenburg	EP 11-01 - Melt Shop Emergency Generator	Diesel	260	HP	CO	Good combustion and operating practices.	2.61	G/HP-HR					BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-02 - Reheat Furnace Emergency Generator	Diesel	190	HP	CO	Good combustion and operating practices.	2.61	G/HP-HR					BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-03 - Rolling Mill Emergency Generator	Diesel	440	HP	CO	Good combustion and operating practices.	2.61	G/HP-HR					BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-04 - IT Emergency Generator	Diesel	190	HP	CO	Good combustion and operating practices.	2.61	G/HP-HR					BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-05 - Radio Tower Emergency Generator	Diesel	61	HP	CO	Good combustion and operating practices.	3.73	G/HP-HR					BACT-PSD	7/23/2020
KY-0115	KY	Nucor Steel Gallatin, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	Diesel	350	HP	CO	Good combustion and operating practices							BACT-PSD	4/19/2021
*LA-0306	LA	Topchem Pollock, LLC	Generator Engine DEG-16-1 (EQT035)	Diesel	460	HP	CO	CFR 60 Subpart IIII; limited operation (100 hr/yr).	3.18	LB/HR	HOURLY MAXIMUM	0.13	TPY	ANNUAL MAXIMUM	BACT-PSD	12/20/2016
LA-0314	LA	Indorama Lake Charles Facility	Diesel Emergency Generator Engine	Diesel	350	HP	CO	Compliance with 40 CFR 63 Subpart ZZZZ.							BACT-PSD	8/3/2016
LA-0323	LA	Monsanto Luling Plant	Standby Generator No. 9 Engine	Diesel	400	HP	CO	Limited operation; compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	1/9/2017
LA-0379	LA	Shintech Plaquemines Plant 1	PVC Emergency Combustion Equipment A	Diesel	450	HP	CO	Good combustion practices/gaseous fuel burning.	8.5	G/HP-HR					BACT-PSD	5/4/2021
LA-0379	LA	Shintech Plaquemines Plant 1	PVC Emergency Combustion Equipment 2A and 2B	Diesel	300	HP	CO	Compliance with 40 CFR 60 Subpart IIII.	2.6	G/HP-HR					BACT-PSD	5/4/2021
*LA-0381	LA	EUEG-5 Unit - Geismar Plant	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	Diesel			CO	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	12/12/2019
LA-0386	LA	LaSalle Bioenergy LLC	Generators and Firewater Pumps Engines	Diesel			CO	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	5/5/2021
NJ-0085	NJ	Middlesex Energy Center, LLC	Emergency Generator	Ultra-low Sulfur Diesel			CO	Use of ultra-low sulfur diesel; limited operation (100 hr/yr).	11.6	LB/HR					BACT-PSD	7/19/2016
*PA-0326	PA	Shell Polymers Monaca Site	Emergency Generator - Parking Garage	Diesel			CO	The use of certified engines; design of engines to include turbocharger and an intercooler/aftercooler; good combustion practices; proper operation and maintenance.	0.5	G/HP-HR					BACT-PSD	2/18/2021
*PA-0326	PA	Shell Polymers Monaca Site	Emergency Generator - Telecom Hut & Tower	Diesel			CO	The use of certified engines; design of engines to include turbocharger and an intercooler/aftercooler; good combustion practices; proper operation and maintenance.	0.5	G/HP-HR					BACT-PSD	2/18/2021
TX-0799	TX	Beaumont Terminal	Emergency Engines	Diesel			CO	Equipment specifications; good combustion practices; limited operation (100 hr/yr).	0.0068	LB/HP-HR					BACT-PSD	6/8/2016
TX-0864	TX	Equistar Chemicals Channelview Complex	Emergency Diesel Engine	Ultra-low Sulfur Diesel			CO	Tier 4 exhaust emission standards specified at 40 CFR 1039.101(b); limited operation (100 hr/yr).							BACT-PSD	9/9/2019
TX-0889	TX	Sweeny Old Ocean Facilities	Emergency Generator Engines	Ultra-low Sulfur Diesel			CO	Good combustion practices; limited operation (100 hr/yr).	100	HR/YR					BACT-PSD	8/8/2020
WI-0291	WI	Graymont Western Lime - Eden	P04 Emergency Diesel Generator	Diesel	35	KW	CO	Good combustion practices.	5	G/KW-HR					BACT-PSD	1/28/2019

Small Diesel Non-Emergency Engines - CO

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0082	AK	Point Thomson Production Facility	Airstrip Generator Engine	Ultra-low Sulfur Diesel	490	HP	CO		2.6	G/HP-HR					BACT-PSD	1/23/2015
AK-0082	AK	Point Thomson Production Facility	Agitator Generator Engine	Ultra-low Sulfur Diesel	98	HP	CO		3.7	G/HP-HR					BACT-PSD	1/23/2015
AK-0082	AK	Point Thomson Production Facility	Incinerator Generator Engine	Ultra-low Sulfur Diesel	102	HP	CO		3.7	G/HP-HR					BACT-PSD	1/23/2015
AK-0084	AK	Donlin Gold Project	Fire Pump Diesel Internal Combustion Engines	Diesel	252	HP	CO	Good combustion practices.	3.3	G/KW-HR	3-HOUR AVERAGE				BACT-PSD	6/30/2017
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Diesel Powered Forklift Engine	Diesel	30	HP	CO	Good combustion practices.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Wireline Diesel Engines	Diesel			CO	Use of good combustion practices with turbocharger, aftercooler, and high injection pressure.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Water Blasting Diesel Engine	Diesel	208	HP	CO	Use of good combustion practices with turbocharger, aftercooler, and high injection pressure.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Well Evaluation Diesel Engine	Diesel	140	HP	CO	Good combustion practices.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Fast Rescue Craft Diesel Engine	Diesel	230	HP	CO	Use of good combustion practices with turbocharger, aftercooler, and high injection pressure.							BACT-PSD	9/16/2014
FL-0347	FL	Anadarko Petroleum Corporation - Egom	Escape Capsule Diesel Engine	Diesel	39	HP	CO	Good combustion practices.							BACT-PSD	9/16/2014
IL-0114	IL	Cronus Chemicals, LLC	Firewater Pump Engine	Distillate Fuel Oil	373	HP	CO	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	3.5	G/KW-HR					BACT-PSD	9/5/2014
IL-0129	IL	CPV Three Rivers Energy Center	Firewater Pump Engine	Ultra-low Sulfur Diesel	422	HP	CO								BACT-PSD	7/30/2018
IL-0130	IL	Jackson Energy Center	Firewater Pump Engine	Ultra-low Sulfur Diesel	420	HP	CO		3.5	G/KW-HR					BACT-PSD	12/31/2018
IL-0133	IL	Lincoln Land Energy Center	Fire Water Pump Engine	Ultra-low Sulfur Diesel	320	HP	CO		3.5	G/KW-HR					BACT-PSD	7/29/2022
KS-0036	KS	Westar Energy - Emporia Energy Center	Cummins 6BTA 5.9F-1 Diesel Engine Fire Pump	No. 2 Fuel Oil	182	BHP	CO	Efficient combustion practices and design technology.	0.53	LB/HR					BACT-PSD	3/18/2013
LA-0309	LA	Benteler Steel Tube Facility	Firewater Pump Engines	Diesel	288	HP	CO	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	6/4/2015
LA-0314	LA	Indorama Lake Charles Facility	Six (6) Diesel Firewater Pump Engines	Diesel	425	HP	CO	complying with 40 CFR 63 subpart ZZZZ							BACT-PSD	8/3/2016
LA-0316	LA	Cameron LNG Facility	Eight (8) Firewater Pump Engines	Diesel	460	HP	CO	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	2/17/2017
LA-0384	LA	Direct Reduced Iron Facility	Internal Combustion Engines	Diesel			CO	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	6/13/2019
LA-0386	LA	LaSalle Bioenergy LLC	Generators and Firewater Pumps Engines	Diesel			CO	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	5/5/2021
MD-0046	MD	Keys Energy Center	Diesel-Fired Fire Pump Engine	Ultra-low Sulfur Diesel	300	HP	CO	Use of ultra-low sulfur diesel; good combustion practices.	3.5	G/KW-HR					BACT-PSD	10/31/2014
NY-0104	NY	CPV Valley Energy Center	Fire Pump	Ultra-low Sulfur Diesel			CO	Good combustion practices.	0.75	LB/MMBTU	1 HR				BACT-PSD	8/1/2013
OH-0383	OH	Petmin USA Incorporated	Black Start Generator (P007)	Diesel	158	HP	CO	Meets EPA Tier 4 requirements in 40 CFR 60 Subpart IIII; good combustion practices.	0.0644	TPY					BACT-PSD	7/17/2020
PA-0286	PA	Moxie Energy LLC/Patriot Generation Plant	Fire Pump Engine	Diesel	460	BHP	CO		0.5	G/HP-HR		0.51	LB/HR		OTHER CASE-BY-CASE	1/31/2013
PA-0309	PA	Lackawanna Energy Center/Jessup	Fire Pump Engine	Ultra-low Sulfur Diesel	15	GAL/HR	CO		0.5	G/HP-HR		0.009	TPY	12-MONTH ROLLING BASIS	BACT-PSD	12/23/2015
TX-0846	TX	Motor Vehicle Assembly Plant	Fire Pump Diesel Engine	No. 2 Diesel Fuel	214	kW	CO	Meets EPA Tier 4 requirements in 40 CFR 60 Subpart IIII.	3.58	G/KW-HR					BACT-PSD	9/23/2018
VA-0325	VA	Greensville Power Station	Diesel-Fired Water Pump	Ultra-low Sulfur Diesel	376	BHP	CO	Good combustion and maintenance practices.	2.6	G/HP-HR					N/A	6/17/2016
WI-0302	WI	WPL - Riverside Energy Center	Diesel-Fired Fire Pump Engine (P04)	Diesel	290	HP	CO	Good combustion practices.	0.33	LB/HR					BACT-PSD	2/28/2020

RBLC – $PM_{10,total}$/$PM_{2.5,total}$

- Process Type 17.130 – Large Natural Gas Engines
- Process Type 17.110 – Large Emergency Diesel Engines
- Process Type 17.210 – Small Emergency Diesel Engines
- Process Type 17.210 – Small Non-Emergency Diesel Engines

Large Natural Gas Generators - PM_{10}

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
KS-0030	KS	Mid-Kansas Electric Company, LLC - Rubart Station	Spark Ignition RICE Electricity Generating Units (EGUs)	Natural Gas	10	MW	Total PM_{10}		1.31	LB/HR	24-HR AVG., EXCLUDING STARTUP	1.68	LB/HR	24-HR AVE. PERIOD, DURING STARTUP	BACT-PSD	3/31/2016
KS-0035	KS	Lacey Randall Generation Facility, LLC	Spark Ignition 4SLB RICE Electric Generating Units (EGUs)	Natural Gas	12526	BHP	Total PM_{10}	Selective catalytic reduction (SCR) system; oxidation catalyst.	2.22	LB/HR	24-HR AVG., EXCLUDING STARTUP	2.65	LB/HR	24-HOUR AVERAGING, DURING STARTUP	BACT-PSD	1/24/2014
MI-0440	MI	Michigan State University	Flexible Group (FG) Engines - 4 RICE	Natural Gas	16500	HP	Total PM_{10}	Natural gas combustion; good combustion practices.	3	LB/HR	EACH ENG/HOURLY EXCEPT STARTUP/ SHUTDOWN				BACT-PSD	5/22/2019
WI-0314	WI	Wisconsin Public Service Corporation - Weston Plant	Reciprocating Internal Combustion Engines (P101-P107)	Natural Gas	152.3	MMBTU/HR	Total PM_{10}	Pipeline-quality natural gas combustion; good combustion practices.	2.37	LB/HR					BACT-PSD	3/10/2022

Large Natural Gas Generators - $PM_{2.5}$

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AR-0163	AR	Big River Steel LLC	Lime Injector Burners	Natural Gas	18.5	MMBTU/HR	Total $PM_{2.5}$	Natural gas combustion; good combustion practices.	0.0075	LB/MMBTU					BACT-PSD	6/9/2019
KS-0030	KS	Mid-Kansas Electric Company, LLC - Rubart Station	Spark Ignition RICE Electricity Generating Units (EGUs)	Natural Gas	10	MW	Total $PM_{2.5}$		1.31	LB/HR	24-HR AVG., EXCLUDING STARTUP	1.68	LB/HR	24-HR AVE. PERIOD, DURING STARTUP	BACT-PSD	3/31/2016
KS-0035	KS	Lacey Randall Generation Facility, LLC	Spark Ignition 4SLB RICE Electric Generating Units (EGUs)	Natural Gas	12526	BHP	Total $PM_{2.5}$	Selective catalytic reduction (SCR) system; oxidation catalyst.	2.22	LB/HR	24-HR AVG., EXCLUDING STARTUP	2.65	LB/HR	24-HOUR AVERAGING, DURING STARTUP	BACT-PSD	1/24/2014
LA-0292	LA	Holbrook Compressor Station	Waukesha 16V-275GL Compressor Engines Nos. 1-12	Natural Gas	5000	HP	Total $PM_{2.5}$	Use of natural gas as fuel; good equipment design; proper combustion techniques.	0.003	LB/HR	HOURLY MAXIMUM	0.01	TPY	ANNUAL MAXIMUM	BACT-PSD	1/22/2016
MI-0440	MI	Michigan State University	Flexible Group (FG) Engines - 4 RICE	Natural Gas	16500	HP	Total $PM_{2.5}$	Natural gas combustion; good combustion practices.	3	LB/HR	EACH ENG/HOURLY EXCEPT STARTUP/ SHUTDOWN				BACT-PSD	5/22/2019
OK-0153	OK	Rose Valley Plant	Compressor Engine (CAT G3606LE)	Natural Gas	1775	HP	Total $PM_{2.5}$	Natural gas combustion practices.	0.01	LB/MMBTU	3-HR AVG				BACT-PSD	3/1/2013
TX-0692	TX	Red Gate Power Plant	Twelve (12) Reciprocating Internal Combustion Engines	Natural Gas	18	MW	Total $PM_{2.5}$								BACT-PSD	12/20/2013
WI-0314	WI	Wisconsin Public Service Corporation - Weston Plant	Reciprocating Internal Combustion Engines (P101-P107)	Natural Gas	152.3	MMBTU/HR	Total $PM_{2.5}$	Pipeline-quality natural gas combustion; good combustion practices.	2.37	LB/HR					BACT-PSD	3/10/2022

Diesel Firewater Pumps - PM_{10}

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0088	AK	Liquefaction Plant	Diesel Fire Pump Engine	Diesel	575	HP	Total PM_{10}	Good combustion practices; limited operation; compliance with 40 CFR 60 Subpart IIII.	0.19	G/HP-HR		10	% OPACITY	6 CONSECUTIVE MINUTES	BACT-PSD	7/7/2022
IN-0317	IN	Riverview Energy Corporation	Emergency Fire Pump (EU6008)	Diesel	750	HP	Total PM_{10}	Compliance with 40 CFR 60 Subpart IIII.	0.2	G/KW-HR					BACT-PSD	6/11/2019
IN-0324	IN	Midwest Fertilizer Company LLC	Firewater Pump (EU015)	Diesel	500	HP	Total PM_{10}	Good combustion practices.	0.15	G/HP-HR		500	HR/YR	TWELVE (12) CONSECUTIVE MONTH PERIOD	BACT-PSD	5/6/2022
KY-0110	KY	Nucor Steel Brandenburg	Emergency Fire Water Pump (EP 10-04)	Diesel	920	HP	Total PM_{10}	Good combustion and operating practices.	0.15	G/HP-HR					BACT-PSD	7/23/2020
*LA-0312	LA	St. James Methanol Plant	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	Diesel	650	HP	Total PM_{10}	Compliance with 40 CFR 60 Subpart IIII.	0.15	LB/HR					BACT-PSD	6/30/2017
LA-0317	LA	Methanex - Geismar Methanol Plant	Firewater Pump Engines	Diesel	896	HP	Total PM_{10}	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.							BACT-PSD	12/22/2016
LA-0323	LA	Monsanto Luling Plant	Fire Water Diesel Pumps No. 3 and 4	Diesel	600	HP	Total PM_{10}	Good operating practices; limited operation; compliance with 40 CFR 60 Subpart IIII							BACT-PSD	1/9/2017
LA-0331	LA	Calcasieu Pass LNG Project	Two (2) Firewater Pumps	Diesel	634	KW	Total PM_{10}	Good combustion and operating practices; limited operation (50 hr/yr).	0.3	G/HP-HR					BACT-PSD	9/21/2018
LA-0364	LA	FG LA Complex	Emergency Fire Water Pumps	Diesel	550	HP	Total PM_{10}	Compliance with 40 CFR 60 Subpart IIII; good combustion and operating practices.							BACT-PSD	1/6/2020
*LA-0388	LA	LACC LLC US - Ethylene Plant	Firewater Pump Engine No. 1 and 2	Diesel	575	HP	Total PM_{10}	Compliance with 40 CFR 60 Subpart IIII.	0.23	LB/HR		0.01	TPY		BACT-PSD	2/25/2022
MI-0448	MI	Grayling Particleboard	Diesel Fire Pump Engine	Diesel	400	KW	Total PM_{10}	Certified engines; good design, operation, and combustion practices; limited operation.	0.18	LB/HR	HOURLY				BACT-PSD	12/18/2020
OH-0375	OH	Long Ridge Energy Generation LLC - Hannibal Power	Emergency Diesel Fire Pump Engine (P002)	Diesel	700	HP	Total PM_{10}	Good combustion design.	0.23	LB/HR		0.012	TPY	PER ROLLING 12 MONTH PERIOD	BACT-PSD	11/7/2017
OH-0383	OH	Petmin USA Incorporated	Diesel-fired Emergency Fire Pumps (P009 and P010)	Diesel	3131	HP	Total PM_{10}	Tier IV NSPS standards and good combustion practices.	0.15	G/BHP-HR					BACT-PSD	7/17/2020
OK-0156	OK	Northstar Agri Industries Enid	Fire Pump Engine	Diesel	550	HP	Total PM_{10}		0.2	G/HP-HR					BACT-PSD	7/31/2013
PA-0311	PA	Moxie Freedom Generation Plant	Fire Pump Engine	Diesel			Total PM_{10}		0.2	G/HP-HR		0.006	TPY	12-MONTH ROLLING BASIS	BACT-PSD	9/1/2015
SC-0193	SC	Mercedes Benz Vans, LLC	Emergency Generators and Fire Pump	No. 2 Fuel Oil	1500	HP	Total PM_{10}	Compliance with 40 CFR 60 Subpart IIII.	100	HR/YR	12 MONTH ROLLING SUM				BACT-PSD	4/15/2016
TX-0876	TX	Port Arthur Ethane Cracker Unit	Emergency Firewater Pumps	Ultra-low Sulfur Diesel			Filterable PM_{10}	Tier 3 exhaust emission standards specified in 40 CFR 89.112; limited operation (100 hr/yr).							BACT-PSD	2/6/2020

Diesel Firewater Pumps - $PM_{2.5}$

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0088	AK	Liquefaction Plant	Diesel Fire Pump Engine	Diesel	575	HP	Total $PM_{2.5}$	Good combustion practices; limited operation; compliance with 40 CFR 60 Subpart IIII.	0.19	G/HP-HR		10	% OPACITY	6 CONSECUTIVE MINUTES	BACT-PSD	7/7/2022
IN-0317	IN	Riverview Energy Corporation	Emergency Fire Pump (EU6008)	Diesel	750	HP	Total $PM_{2.5}$	Compliance with 40 CFR 60 Subpart IIII.	0.2	G/KWH					BACT-PSD	6/11/2019
IN-0324	IN	Midwest Fertilizer Company LLC	Firewater Pump (EU015)	Diesel	500	HP	Total $PM_{2.5}$	Good combustion practices.	0.15	G/HP-HR		500	HR/YR	TWELVE (12) CONSECUTIVE MONTH PERIOD	BACT-PSD	5/6/2022
KY-0110	KY	Nucor Steel Brandenburg	Emergency Fire Water Pump (EP 10-04)	Diesel	920	HP	Total $PM_{2.5}$	Good combustion and operating practices.	0.15	G/HP-HR					BACT-PSD	7/23/2020
*LA-0312	LA	St. James Methanol Plant	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	Diesel	650	HP	Total $PM_{2.5}$	Compliance with 40 CFR 60 Subpart IIII.	0.15	LB/HR					BACT-PSD	6/30/2017
*LA-0315	LA	G2G Plant	Fire Pump Diesel Engines 1 and 2	Diesel	751	HP	Total $PM_{2.5}$	Proper design and operation; use of ultra-low sulfur diesel.	0.25	LB/HR	HOURLY MAXIMUM	0.01	TPY	ANNUAL MAXIMUM	BACT-PSD	5/23/2014
LA-0317	LA	Methanex - Geismar Methanol Plant	Firewater Pump Engines	Diesel	896	HP	Total $PM_{2.5}$	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.							BACT-PSD	12/22/2016
LA-0323	LA	Monsanto Luling Plant	Fire Water Diesel Pumps No. 3 and 4	Diesel	600	HP	Total $PM_{2.5}$	Good operating practices; limited operation; compliance with 40 CFR 60 Subpart IIII							BACT-PSD	1/9/2017
LA-0331	LA	Calcasieu Pass LNG Project	Two (2) Firewater Pumps	Diesel	634	KW	Total $PM_{2.5}$	Good combustion and operating practices; limited operation (50 hr/yr).	0.3	G/HP-HR					BACT-PSD	9/21/2018
LA-0364	LA	FG LA Complex	Emergency Fire Water Pumps	Diesel	550	HP	Total $PM_{2.5}$	Compliance with 40 CFR 60 Subpart IIII; good combustion and operating practices.							BACT-PSD	1/6/2020
*LA-0388	LA	LACC LLC US - Ethylene Plant	Firewater Pump Engine No. 1 and 2	Diesel	575	HP	Total $PM_{2.5}$	Compliance with 40 CFR 60 Subpart IIII.	0.23	LB/HR		0.01	TPY		BACT-PSD	2/25/2022
MI-0448	MI	Grayling Particleboard	Diesel Fire Pump Engine	Diesel	400	KW	Total $PM_{2.5}$	Certified engines; good design, operation, and combustion practices; limited operation.	0.18	LB/HR	HOURLY				BACT-PSD	12/18/2020
OH-0375	OH	Long Ridge Energy Generation LLC - Hannibal Power	Emergency Diesel Fire Pump Engine (P002)	Diesel	700	HP	Total $PM_{2.5}$	Good combustion design.	0.23	LB/HR		0.012	TPY	PER ROLLING 12 MONTH PERIOD	BACT-PSD	11/7/2017
OH-0383	OH	Petmin USA Incorporated	Diesel-fired Emergency Fire Pumps (P009 and P010)	Diesel	3131	HP	Total $PM_{2.5}$	Tier IV NSPS standards and good combustion practices.	0.15	G/BHP-HR					BACT-PSD	7/17/2020
OK-0156	OK	Northstar Agri Industries Enid	Fire Pump Engine	Diesel	550	HP	Total $PM_{2.5}$		0.2	G/HP-HR					BACT-PSD	7/31/2013
PA-0311	PA	Moxie Freedom Generation Plant	Fire Pump Engine	Diesel			Total $PM_{2.5}$		2	HP-HR		0.006	TPY	12-MONTH ROLLING BASIS	BACT-PSD	9/1/2015
SC-0193	SC	Mercedes Benz Vans, LLC	Emergency Generators and Fire Pump	No. 2 Fuel Oil	1500	HP	Total $PM_{2.5}$	Compliance with 40 CFR 60 Subpart IIII.	100	HR/YR	12 MONTH ROLLING SUM				BACT-PSD	4/15/2016
TX-0876	TX	Port Arthur Ethane Cracker Unit	Emergency Firewater Pumps	Ultra-low Sulfur Diesel			Filterable $PM_{2.5}$	Tier 3 exhaust emission standards specified in 40 CFR 89.112; limited operation (100 hr/yr).							BACT-PSD	2/6/2020

Small Diesel Emergency Engines - PM_{10}

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Case-by-Case Basis	Permit Date
AK-0085	AK	Gas Treatment Plant	Two (2) Emergency Diesel Generators	Ultra-low Sulfur Diesel	335	HP	Total PM_{10}	Good combustion practices; use of ultra-low sulfur diesel; limited operation (500 hr/yr).	0.19	G/HP-HR	3-HOUR AVERAGE			BACT-PSD	8/13/2020
AR-0173	AR	Big River Steel LLC	Emergency Engines	Diesel			Total PM_{10}	Good operating practices; limited operation; compliance with 40 CFR 60 Subpart IIII.	0.1	G/BHP-HR				BACT-PSD	1/31/2022
IN-0295	IN	Steel Dynamics, Inc. - Engineered Bar Products Division	Emergency Diesel Generators	Diesel	75 - 150	HP	Filterable PM_{10}	Good combustion, operating, and maintenance practices.	1.34	G/KW-HR		0.0022	LB/HP-HR	BACT-PSD	2/23/2018
KY-0110	KY	Nucor Steel Brandenburg	EP 11-01 - Melt Shop Emergency Generator	Diesel	260	HP	Total PM_{10}	Good combustion and operating practices.	0.15	G/HP-HR				BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-02 - Reheat Furnace Emergency Generator	Diesel	190	HP	Total PM_{10}	Good combustion and operating practices.	0.15	G/HP-HR				BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-03 - Rolling Mill Emergency Generator	Diesel	440	HP	Total PM_{10}	Good combustion and operating practices.	0.15	G/HP-HR				BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-04 - IT Emergency Generator	Diesel	190	HP	Total PM_{10}	Good combustion and operating practices.	0.15	G/HP-HR				BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-05 - Radio Tower Emergency Generator	Diesel	61	HP	Total PM_{10}	Good combustion and operating practices.	0.3	G/HP-HR				BACT-PSD	7/23/2020
KY-0115	KY	Nucor Steel Gallatin, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	Diesel	350	HP	Total PM_{10}	Good combustion and operating practices.	0.15	G/HP-HR				BACT-PSD	4/19/2021
LA-0314	LA	Indorama Lake Charles Facility	Diesel Emergency Generator Engine	Diesel	350	HP	Total PM_{10}	Compliance with 40 CFR 63 Subpart ZZZZ.						BACT-PSD	8/3/2016
LA-0323	LA	Monsanto Luling Plant	Standby Generator No. 9 Engine	Diesel	400	HP	Total PM_{10}	Good operating practices; limited operation; compliance with 40 CFR 60 Subpart IIII.						BACT-PSD	1/9/2017
LA-0379	LA	Shintech Plaquemines Plant 1	PVC Emergency Combustion Equipment A	Diesel	450	HP	Total PM_{10}	Good combustion practices/gaseous fuel burning.	0.4	G/HP-HR				BACT-PSD	5/4/2021
LA-0379	LA	Shintech Plaquemines Plant 1	PVC Emergency Combustion Equipment 2A and 2B	Diesel	300	HP	Total PM_{10}	Compliance with 40 CFR 60 Subpart IIII.	0.15	G/HP-HR				BACT-PSD	5/4/2021
*LA-0381	LA	EUEG-5 Unit - Geismar Plant	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	Diesel			Filterable PM_{10}	Compliance with 40 CFR 60 Subpart IIII; limited operation (100 hr/yr).						BACT-PSD	12/12/2019
LA-0386	LA	LaSalle Bioenergy LLC	Generators and Firewater Pumps Engines	Diesel			Total PM_{10}	Comply with 40 CFR 60 Subpart IIII						BACT-PSD	5/5/2021
MI-0447	MI	LBWL - Erickson Station	Emergency Engine	Diesel	315	HP	Total PM_{10}	Use of ultra-low sulfur diesel fuel; good combustion practices.	0.12	LB/HR	HOURLY			BACT-PSD	1/7/2021
NJ-0085	NJ	Middlesex Energy Center, LLC	Emergency Generator	Ultra-low Sulfur Diesel			Total PM_{10}	Use of ultra-low sulfur diesel; limited operation (100 hr/yr).	0.661	LB/HR				BACT-PSD	7/19/2016
TX-0864	TX	Equistar Chemicals Channelview Complex	Emergency Diesel Engine	Ultra-low Sulfur Diesel			Total PM_{10}	at 40 CFR 1039.101(b); limited operation (100 hr/yr).						BACT-PSD	9/9/2019
WI-0271	WI	Kohler Co-Metals Processing Complex	Diesel Powered Emergency Generator	Distillate Fuel	465	HP	Total PM_{10}	Limited operation (200 hr/yr).	0.29	LB/HR				BACT-PSD	6/5/2015

Small Diesel Emergency Engines - $PM_{2.5}$

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0085	AK	Gas Treatment Plant	Two (2) Emergency Diesel Generators	Ultra-low Sulfur Diesel	335	HP	Total $PM_{2.5}$	Good combustion practices; use of ultra-low sulfur diesel; limited operation (500 hr/yr).	0.19	G/HP-HR	3-HOUR AVERAGE				BACT-PSD	8/13/2020
AR-0173	AR	Big River Steel LLC	Emergency Engines	Diesel			Total $PM_{2.5}$	Good operating practices; limited operation; compliance with 40 CFR 60 Subpart IIII.	0.1	G/BHP-HR					BACT-PSD	1/31/2022
KY-0110	KY	Nucor Steel Brandenburg	EP 11-01 - Melt Shop Emergency Generator	Diesel	260	HP	Total $PM_{2.5}$	Good combustion and operating practices.	0.15	G/HP-HR					BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-02 - Reheat Furnace Emergency Generator	Diesel	190	HP	Total $PM_{2.5}$	Good combustion and operating practices.	0.15	G/HP-HR					BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-03 - Rolling Mill Emergency Generator	Diesel	440	HP	Total $PM_{2.5}$	Good combustion and operating practices.	0.15	G/HP-HR					BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-04 - IT Emergency Generator	Diesel	190	HP	Total $PM_{2.5}$	Good combustion and operating practices.	0.15	G/HP-HR					BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-05 - Radio Tower Emergency Generator	Diesel	61	HP	Total $PM_{2.5}$	Good combustion and operating practices.	0.3	G/HP-HR					BACT-PSD	7/23/2020
KY-0115	KY	Nucor Steel Gallatin, LLC	Cold Mill Complex Emergency Generator (EP 09-05)	Diesel	350	HP	Total $PM_{2.5}$	Good combustion and operating practices.	0.15	G/HP-HR					BACT-PSD	4/19/2021
*LA-0306	LA	Topchem Pollock, LLC	Generator Engine DEG-16-1 (EQT035)	Diesel	460	HP	Total $PM_{2.5}$	CFR 60 Subpart IIII; limited operation (100 hr/yr).	0.18	LB/HR	HOURLY MAXIMUM	0.01	TPY	ANNUAL MAXIMUM	BACT-PSD	12/20/2016
LA-0314	LA	Indorama Lake Charles Facility	Diesel Emergency Generator Engine	Diesel	350	HP	Total $PM_{2.5}$	Compliance with 40 CFR 63 Subpart ZZZZ.							BACT-PSD	8/3/2016
LA-0379	LA	Shintech Plaquemines Plant 1	PVC Emergency Combustion Equipment 2A and 2B	Diesel	300	HP	Total $PM_{2.5}$	Compliance with 40 CFR 60 Subpart IIII.	0.15	G/HP-HR					BACT-PSD	5/4/2021
LA-0386	LA	LaSalle Bioenergy LLC	Generators and Firewater Pumps Engines	Diesel			Total $PM_{2.5}$	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	5/5/2021
MI-0447	MI	LBWL - Erickson Station	Emergency Engine	Diesel	315	HP	Total $PM_{2.5}$	Use of ultra-low sulfur diesel fuel; good combustion practices.	0.12	LB/HR	HOURLY				BACT-PSD	1/7/2021
NJ-0085	NJ	Middlesex Energy Center, LLC	Emergency Generator	Ultra-low Sulfur Diesel			Total $PM_{2.5}$	Use of ultra-low sulfur diesel; limited operation (100 hr/yr).	0.661	LB/HR					BACT-PSD	7/19/2016
*PA-0326	PA	Shell Polymers Monaca Site	Emergency Generator - Parking Garage	Diesel			Total $PM_{2.5}$	The use of certified engines; design of engines to include turbocharger and an intercooler/aftercooler; good combustion practices; proper operation and maintenance.	0.06	G/HP-HR					LAER	2/18/2021
*PA-0326	PA	Shell Polymers Monaca Site	Emergency Generator - Telecom Hut & Tower	Diesel			Total $PM_{2.5}$	The use of certified engines; design of engines to include turbocharger and an intercooler/aftercooler; good combustion practices; proper operation and maintenance.	0.22	G/HP-HR					LAER	2/18/2021
TX-0864	TX	Equistar Chemicals Channelview Complex	Emergency Diesel Engine	Ultra-low Sulfur Diesel			Total $PM_{2.5}$	40 CFR 1039.101(b); limited operation (100 hr/yr).							BACT-PSD	9/9/2019
WI-0271	WI	Kohler Co-Metals Processing Complex	Diesel Powered Emergency Generator	Distillate Fuel	465	HP	Total $PM_{2.5}$	Limited operation (200 hr/yr).	0.29	LB/HR					BACT-PSD	6/5/2015

Small Diesel Non-Emergency Engines - PM_{10}

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0082	AK	Point Thomson Production Facility	Airstrip Generator Engine	Ultra-low Sulfur Diesel	490	HP	Filterable PM_{10}		0.15	G/HP-HR					BACT-PSD	1/23/2015
AK-0082	AK	Point Thomson Production Facility	Agitator Generator Engine	Ultra-low Sulfur Diesel	98	HP	Filterable PM_{10}		0.3	G/HP-HR					BACT-PSD	1/23/2015
AK-0082	AK	Point Thomson Production Facility	Incinerator Generator Engine	Ultra-low Sulfur Diesel	102	HP	Filterable PM_{10}		0.22	G/HP-HR					BACT-PSD	1/23/2015
AK-0084	AK	Donlin Gold Project	Fire Pump Diesel Internal Combustion Engines	Diesel	252	HP	Total PM_{10}	Clean fuel; good combustion practices.	0.19	G/KW-HR	3-HOUR AVERAGE				BACT-PSD	6/30/2017
IL-0114	IL	Cronus Chemicals, LLC	Firewater Pump Engine	Distillate Fuel Oil	373	HP	Total PM_{10}	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.1	G/KW-HR					BACT-PSD	9/5/2014
LA-0308	LA	Morgan City Power Plant	Diesel Fired Pump Engine	Diesel	380	HP	Total PM_{10}	Good combustion and maintenance practices; compliance with NSPS 40 CFR 60 Subpart IIII.	0.15	LB/HR	HOURLY MAXIMUM	0.01	TPY	ANNUAL MAXIMUM	BACT-PSD	9/26/2013
LA-0309	LA	Benteler Steel Tube Facility	Firewater Pump Engines	Diesel	288	HP	Total PM_{10}	Compliance with 40 CFR 60 Subpart IIII.	0.15	G/BHP-HR					BACT-PSD	6/4/2015
LA-0314	LA	Indorama Lake Charles Facility	Six (6) Diesel Firewater Pump Engines	Diesel	425	HP	Total PM_{10}	Compliance with 40 CFR 63 Subpart ZZZZ.							BACT-PSD	8/3/2016
LA-0316	LA	Cameron LNG Facility	Eight (8) Firewater Pump Engines	Diesel	460	hp	Total PM_{10}	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	2/17/2017
LA-0384	LA	Direct Reduced Iron Facility	Internal Combustion Engines	Diesel			Total PM_{10}	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	6/13/2019
LA-0386	LA	LaSalle Bioenergy LLC	Generators and Firewater Pumps Engines	Diesel			Total PM_{10}	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	5/5/2021
MD-0046	MD	Keys Energy Center	Diesel-Fired Fire Pump Engine	Ultra-low Sulfur Diesel	300	HP	Total PM_{10}	Exclusive use of ultra-low sulfur diesel; good combustion practices.	0.18	G/HP-HR					BACT-PSD	10/31/2014
OH-0379	OH	Petmin USA Incorporated	Black Start Generator (P007)	Diesel	158	HP	Filterable PM_{10}	Good combustion practices; meets EPA Tier 4 requirements in 40 CFR 60 Subpart IIII.	0.00522	LB/HR		0.000261	TPY		BACT-PSD	2/6/2019
PA-0286	PA	Moxie Energy LLC/Patriot Generation Plant	Fire Pump Engine	Diesel	460	BHP	Total PM_{10}		0.09	G/HP-HR		0.09	LB/HR		OTHER CASE-BY-CASE	1/31/2013
PA-0309	PA	Lackawanna Energy Center/Jessup	Fire Pump Engine	Ultra-low Sulfur Diesel	15	GAL/HR	Total PM_{10}		0.11	G/HP-HR		0.002	TPY	12-MONTH ROLLING BASIS	BACT-PSD	12/23/2015
TX-0846	TX	Motor Vehicle Assembly Plant	Fire Pump Diesel Engine	No. 2 Diesel Fuel	214	kW	Total PM_{10}	Meets EPA Tier 4 requirements in 40 CFR 60 Subpart IIII.	0.02	G/KW-HR					BACT-PSD	9/23/2018
VA-0325	VA	Greensville Power Station	Diesel-Fired Water Pump	Ultra-low Sulfur Diesel	376	BHP	Total PM_{10}	Use of ultra-low sulfur diesel (15 ppm max).	0.3	G/HP-HR					N/A	6/17/2016

Small Diesel Non-Emergency Engines - $PM_{2.5}$

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0081	AK	Point Thomson Production Facility	Combustion Engines	Ultra-low Sulfur Diesel	493	HP	Total $PM_{2.5}$	Good combustion and operating practices.	0.2	G/KW-HR					OTHER CASE-BY-CASE	6/12/2013
AK-0082	AK	Point Thomson Production Facility	Airstrip Generator Engine	Ultra-low Sulfur Diesel	490	HP	Filterable $PM_{2.5}$		0.15	G/HP-HR					BACT-PSD	1/23/2015
AK-0082	AK	Point Thomson Production Facility	Agitator Generator Engine	Ultra-low Sulfur Diesel	98	HP	Filterable $PM_{2.5}$		0.3	G/HP-HR					BACT-PSD	1/23/2015
AK-0082	AK	Point Thomson Production Facility	Incinerator Generator Engine	Ultra-low Sulfur Diesel	102	HP	Filterable $PM_{2.5}$		0.22	G/HP-HR					BACT-PSD	1/23/2015
AK-0084	AK	Donlin Gold Project	Fire Pump Diesel Internal Combustion Engines	Diesel	252	HP	Total $PM_{2.5}$	Clean fuel; good combustion practices.	0.19	G/KW-HR	3-HOUR AVERAGE				BACT-PSD	6/30/2017
IL-0114	IL	Cronus Chemicals, LLC	Firewater Pump Engine	Distillate Fuel Oil	373	HP	Total $PM_{2.5}$	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	0.1	G/KW-HR					BACT-PSD	9/5/2014
LA-0308	LA	Morgan City Power Plant	Diesel Fired Pump Engine	Diesel	380	HP	Filterable $PM_{2.5}$	Good combustion and maintenance practices; compliance with NSPS 40 CFR 60 Subpart IIII.	0.15	LB/HR	HOURLY MAXIMUM	0.01	TPY	ANNUAL MAXIMUM	BACT-PSD	9/26/2013
LA-0309	LA	Benteler Steel Tube Facility	Firewater Pump Engines	Diesel	288	HP	Total $PM_{2.5}$	Compliance with 40 CFR 60 Subpart IIII.	0.15	G/BHP-HR					BACT-PSD	6/4/2015
LA-0314	LA	Indorama Lake Charles Facility	Six (6) Diesel Firewater Pump Engines	Diesel	425	HP	Total $PM_{2.5}$	Compliance with 40 CFR 63 Subpart ZZZZ.							BACT-PSD	8/3/2016
LA-0316	LA	Cameron LNG Facility	Eight (8) Firewater Pump Engines	Diesel	460	HP	Total $PM_{2.5}$	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	2/17/2017
LA-0384	LA	Direct Reduced Iron Facility	Internal Combustion Engines	Diesel			Total $PM_{2.5}$	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	6/13/2019
LA-0386	LA	LaSalle Bioenergy LLC	Generators and Firewater Pumps Engines	Diesel			Total $PM_{2.5}$	Compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	5/5/2021
MS-0092	MS	Emberclear GTL Mississippi	Diesel Firewater Pumps	Diesel	325	HP	Total $PM_{2.5}$								BACT-PSD	5/8/2014
OH-0379	OH	Petmin USA Incorporated	Black Start Generator (P007)	Diesel	158	HP	Filterable $PM_{2.5}$	Good combustion practices; meets EPA Tier 4 requirements in 40 CFR 60 Subpart IIII.	0.00522	LB/HR		0.000261	TPY		BACT-PSD	2/6/2019
PA-0286	PA	Moxie Energy LLC/Patriot Generation Plant	Fire Pump Engine	Diesel	460	BHP	Total $PM_{2.5}$		0.09	G/HP-HR		0.09	LB/HR		OTHER CASE-BY-CASE	1/31/2013
PA-0309	PA	Lackawanna Energy Center/Jessup	Fire Pump Engine	Ultra-low Sulfur Diesel	15	GAL/HR	Total $PM_{2.5}$		0.11	G/HP-HR		0.002	TPY	12-MONTH ROLLING BASIS	BACT-PSD	12/23/2015
TX-0846	TX	Motor Vehicle Assembly Plant	Fire Pump Diesel Engine	No. 2 Diesel Fuel	214	kW	Total $PM_{2.5}$	Meets EPA Tier 4 requirements in 40 CFR 60 Subpart IIII.	0.02	G/KW-HR					BACT-PSD	9/23/2018
VA-0325	VA	Greensville Power Station	Diesel-Fired Water Pump	Ultra-low Sulfur Diesel	376	BHP	Total $PM_{2.5}$	Use of ultra-low sulfur diesel (15 ppm max).	0.3	G/HP-HR					N/A	6/17/2016

RBLC – GHG

- Process Type 17.130 – Large Natural Gas Engines
- Process Type 17.110 – Large Emergency Diesel Engines
- Process Type 17.210 – Small Emergency Diesel Engines
- Process Type 17.210 – Small Non-Emergency Diesel Engines

Large Natural Gas Generators - GHG

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
FL-0370	FL	Arvah B. Hopkins Generating Station	SI Internal Combustion Engine Units 1A-1E	Natural Gas	18.82	MW	CO_2e	Thermally efficient design; use of natural gas as fuel; good combustion and maintenance practices.	1110	LB/MWH, BASED ON HHV	THREE 1-HOUR TEST RUNS @ 100%, 70% & 40%				BACT-PSD	4/3/2019
KS-0030	KS	Mid-Kansas Electric Company, LLC - Rubart Station	Spark Ignition RICE Electricity Generating Units (EGUs)	Natural Gas	10	MW	CO_2e		10692	LB/HR	ANNUAL AVE. PERIOD, EXCEPT DURING STARTUP	10476	LB/HR	ANNUAL AVE. PERIOD, DURING STARTUP	BACT-PSD	3/31/2016
KS-0035	KS	Lacey Randall Generation Facility, LLC	Spark Ignition 4SLB RICE Electric Generating Units (EGUs)	Natural Gas	12526	BHP	CO_2e		9330	LB/HR	ANNUAL AVERAGING, EXCLUDING STARTUP				BACT-PSD	1/24/2014
LA-0266	LA	Eunice Gas Extraction Plant	Compressor Engines 1, 2, & 3 (EQT 0057, 0058, & 0059)	Natural gas	3550	HP	CO_2e	Compliance with 40 CFR 60 Subpart JJJJ.							BACT-PSD	5/1/2013
LA-0292	LA	Holbrook Compressor Station	Waukesha 16V-275GL Compressor Engines Nos. 1-12	Natural Gas	5000	HP	CO_2e		21170	TPY	ANNUAL MAXIMUM				BACT-PSD	1/22/2016
MI-0440	MI	Michigan State University	Flexible Group (FG) Engines - 4 RICE	Natural Gas	16500	HP	CO_2e	Use of low-carbon fuels; energy efficiency measures and preventative maintenance pursuant to manufacturer recommendations.	48724	TPY	12-MO ROLLING TIME PERIOD				BACT-PSD	5/22/2019
OK-0153	OK	Rose Valley Plant	Compressor Engine (CAT G3606LE)	Natural Gas	1775	HP	CO_2e		8452	BTU/BHP-HR	3-HR AVG				BACT-PSD	3/1/2013
TX-0636	TX	Houston Central Gas Plant	Combustion Turbines	Natural Gas	15000	HP	CO_2e		65097	TPY	12 MONTH ROLLING AVG				BACT-PSD	3/8/2013
TX-0746	TX	Nuevo Midstream, Ramsey Gas Plant	Gas-Fired Internal Combustion Cor	Natural Gas	206149	MMBTU/YR	CO_2e		412.3	LB CO_2/MMSCF	12-MONTH ROLLING BASIS, INCLUDES MSS	78490	TPY CO_2E	12-MONTH ROLLING AVERAGE, INCLUDES MSS	BACT-PSD	11/18/2014
WI-0314	WI	Wisconsin Public Service Corporation - Weston Plant	Reciprocating Internal Combustion Engines (P101-P107)	Natural Gas	152.3	MMBTU/HR	CO_2e	Good combustion practices; use of pipeline quality natural gas.	1100	LB/MWH ELEC. OUTPUT	ANY 12-CONSECUTIVE-OPERATING-MONTHS				BACT-PSD	3/10/2022

Diesel Firewater Pumps - GHG

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Emission Limit 2 Averaging Time	Case-by-Case Basis	Permit Date
AK-0088	AK	Liquefaction Plant	Diesel Fire Pump Engine	Diesel	575	HP	CO_2e	Good combustion practices; limited operation.	163.6	LB/MMBTU	3-HOURS	500	HR/YR		BACT-PSD	7/7/2022
IN-0317	IN	Riverview Energy Corporation	Emergency Fire Pump (EU6008)	Diesel	750	HP	CO_2e	Good combustion practicles; compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.	217	TPY					BACT-PSD	6/11/2019
IN-0324	IN	Midwest Fertilizer Company LLC	Firewater Pump (EU015)	Diesel	500	HP	CO_2e	Good combustion practices.	527.4	G/HP-HR		500	HR/YR	TWELVE (12) CONSECUTIVE MONTH PERIOD	BACT-PSD	5/6/2022
KY-0110	KY	Nucor Steel Brandenburg	Emergency Fire Water Pump (EP 10-04)	Diesel	920	HP	CO_2e	Good combustion and operating practices.							BACT-PSD	7/23/2020
*LA-0312	LA	St. James Methanol Plant	DFP1-13 - Diesel Fire Pump Engine (EQT0013)	Diesel	650	horsepower	CO_2e	Compliance with 40 CFR 60 Subpart IIII.	37	TPY					BACT-PSD	6/30/2017
*LA-0315	LA	G2G Plant	Fire Pump Diesel Engines 1 and 2	Diesel	751	HP	CO_2e	Proper design and operation; use of ultra-low sulfur diesel.							BACT-PSD	5/23/2014
LA-0317	LA	Methanex - Geismar Methanol Plant	Firewater Pump Engines	Diesel	896	hp (each)	CO_2e	Compliance with 40 CFR 60 Subpart IIII and 40 CFR 63 Subpart ZZZZ.							BACT-PSD	12/22/2016
LA-0323	LA	Monsanto Luling Plant	Fire Water Diesel Pumps No. 3 and 4	Diesel	600	hp	CO_2e	Good operating practices; limited operation; compliance with 40 CFR 60 Subpart IIII.							BACT-PSD	1/9/2017
LA-0331	LA	Calcasieu Pass LNG Project	Two (2) Firewater Pumps	Diesel	634	kW	CO_2e	Good combustion, operating, and maintenance practices.	44	TPY	ANNUAL TOTAL				BACT-PSD	9/21/2018
LA-0364	LA	FG LA Complex	Emergency Fire Water Pumps	Diesel	550	hp	CO_2e	Compliance with 40 CFR 60 Subpart IIII; good combustion and operating practices.							BACT-PSD	1/6/2020
*LA-0388	LA	LACC LLC US - Ethylene Plant	Firewater Pump Engine No. 1 and 2	Diesel	575	hp	CO_2e	Compliance with 40 CFR 60 Subpart IIII.	33	TPY					BACT-PSD	2/25/2022
MI-0448	MI	Grayling Particleboard	Diesel Fire Pump Engine	Diesel	400	kW	CO_2e	Good combustion and design practices; limited operation (500 hr/yr).	56	TPY	12-MONTH ROLLING BASIS				BACT-PSD	12/18/2020
OH-0375	OH	Long Ridge Energy Generation LLC - Hannibal Power	Emergency Diesel Fire Pump Engine (P002)	Diesel	700	HP	CO_2e	Efficient design.	40.1	TPY	PER ROLLING 12 MONTH PERIOD				BACT-PSD	11/7/2017
PA-0311	PA	Moxie Freedom Generation Plant	Fire Pump Engine	Diesel			CO_2e		14	TPY	12-MONTH ROLLING BASIS				BACT-PSD	9/1/2015
TX-0799	TX	Beaumont Terminal	Fire Pump Engines	Diesel			CO_2e	Equipment specifications and good combustion practices; limited operation (100 hr/yr).	72.16	TPY					BACT-PSD	6/8/2016
TX-0876	TX	Port Arthur Ethane Cracker Unit	Emergency Firewater Pumps	Ultra-low Sulfur Diesel			CO_2e	Tier 3 exhaust emission standards specified in 40 CFR 89.112; limited operation (100 hr/yr).							BACT-PSD	2/6/2020
WI-0297	WI	Green Bay Packaging - Mill Division	Diesel-Fired Emergency Fire Pump (P36)	Diesel	510	HP	CO_2e	Compliance with 40 CFR 60 Subpart IIII; limited operation (200 hr/yr).	200	HR/YR	IN ANY CONSECUTIVE 12-MONTH PERIOD				BACT-PSD	12/10/2019

Small Diesel Emergency Engines - GHG

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Case-by-Case Basis	Permit Date
AK-0085	AK	Gas Treatment Plant	Two (2) Emergency Diesel Generators	Ultra-low Sulfur Diesel	335	HP	CO_2e	Good combustion practices; limited operation (500 hr/yr).	163.6	LB/MMBTU	3-HOUR AVERAGE			BACT-PSD	8/13/2020
AR-0173	AR	Big River Steel LLC	Emergency Engines	Diesel			CO_2e	Good operating practices.	164	LB/MMBTU				BACT-PSD	1/31/2022
KY-0110	KY	Nucor Steel Brandenburg	EP 11-01 - Melt Shop Emergency Generator	Diesel	260	HP	CO_2e	Good combustion and operating practices.						BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-02 - Reheat Furnace Emergency Generator	Diesel	190	HP	CO_2e	Good combustion and operating practices.						BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-03 - Rolling Mill Emergency Generator	Diesel	440	HP	CO_2e	Good combustion and operating practices.						BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-04 - IT Emergency Generator	Diesel	190	HP	CO_2e	Good combustion and operating practices.						BACT-PSD	7/23/2020
KY-0110	KY	Nucor Steel Brandenburg	EP 11-05 - Radio Tower Emergency Generator	Diesel	61	HP	CO_2e	Good combustion and operating practices.						BACT-PSD	7/23/2020
*LA-0306	LA	Topchem Pollock, LLC	Generator Engine DEG-16-1 (EQT035)	Diesel	460	HP	CO_2e	CFR 60 Subpart IIII; limited operation (100 hr/yr).	26	TPY	ANNUAL MAXIMUM			BACT-PSD	12/20/2016
LA-0314	LA	Indorama Lake Charles Facility	Diesel Emergency Generator Engine	Diesel	350	HP	CO_2e							BACT-PSD	8/3/2016
LA-0323	LA	Monsanto Luling Plant	Standby Generator No. 9 Engine	Diesel	400	HP	CO_2e	Limited operation; compliance with 40 CFR 60 Subpart IIII.						BACT-PSD	1/9/2017
*LA-0381	LA	EUEG-5 Unit - Geismar Plant	Emergency Engines 2-19 and 3-19 (EQT0904 and EQT0905)	Diesel			CO_2e	Good engine design and work practices.						BACT-PSD	12/12/2019
LA-0386	LA	LaSalle Bioenergy LLC	Generators and Firewater Pumps Engines	Diesel			CO_2e	Compliance with 40 CFR 60 Subpart IIII.						BACT-PSD	5/5/2021
MI-0447	MI	LBWL - Erickson Station	Emergency Engine	Diesel	315	HP	CO_2e	Low carbon fuel (pipeline quality natural gas), good combustion practices and energy efficiency measures.	20	TPY	12-MO ROLLING TIME PERIOD			BACT-PSD	1/7/2021
*PA-0326	PA	Shell Polymers Monaca Site	Emergency Generator - Parking Garage	Diesel			CO_2e	Good combustion practices - no feasible control technologies.	10	TPY	YEARLY ON 12 MONTH ROLLING			BACT-PSD	2/18/2021
*PA-0326	PA	Shell Polymers Monaca Site	Emergency Generator - Telecom Hut & Tower	Diesel			CO_2e	Good combustion practices - no feasible control technologies.	10	TPY	YEARLY ON 12 MONTH ROLLING			BACT-PSD	2/18/2021
TX-0799	TX	Beaumont Terminal	Emergency Engines	Diesel			CO_2e	Equipment specifications; good combustion practices; limited operation (100 hr/yr).	6.79	TPY				BACT-PSD	6/8/2016
TX-0824	TX	Jackson County Generating Facility	Emergency Diesel-Fired Equipmer	Diesel	160	HP	CO_2e	Good operating and maintenance practices; efficient design; low annual capacity.	13	TPY				BACT-PSD	6/30/2017
TX-0864	TX	Equistar Chemicals Channelview Complex	Emergency Diesel Engine	Ultra-low Sulfur Diesel			CO_2e	Tier 4 exhaust emission standards specified at 40 CFR 1039.101(b).						BACT-PSD	9/9/2019
TX-0889	TX	Sweeny Old Ocean Facilities	Emergency Generator Engines	Ultra-low Sulfur Diesel			CO_2e	Good combustion practices; limited operation.						BACT-PSD	8/8/2020

Small Diesel Non-Emergency Engines - GHG

RBLCID	State	Facility	Process Name	Primary Fuel	Engine Rating	Engine Rating Unit	Pollutant	Control Method Description	Emission Limit 1	Emission Limit 1 Unit	Emission Limit 1 Averaging Time	Emission Limit 2	Emission Limit 2 Unit	Case-by-Case Basis	Permit Date
AK-0082	AK	Point Thomson Production Facility	Airstrip Generator Engine	Ultra-low Sulfur Diesel	490	HP	CO_2e		163	TPY				BACT-PSD	1/23/2015
AK-0082	AK	Point Thomson Production Facility	Agitator Generator Engine	Ultra-low Sulfur Diesel	98	HP	CO_2e		356	TPY				BACT-PSD	1/23/2015
AK-0082	AK	Point Thomson Production Facility	Incinerator Generator Engine	Ultra-low Sulfur Diesel	102	HP	CO_2e		516	TPY				BACT-PSD	1/23/2015
AK-0084	AK	Donlin Gold Project	Fire Pump Diesel Internal Combustion Engines	Diesel	252	HP	CO_2e	Good combustion practices.	216	TPY	YEARLY			BACT-PSD	6/30/2017
IL-0114	IL	Cronus Chemicals, LLC	Firewater Pump Engine	Distillate Fuel Oil	373	HP	CO_2e	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7.	72	TPY				BACT-PSD	9/5/2014
IL-0129	IL	CPV Three Rivers Energy Center	Firewater Pump Engine	Ultra-low Sulfur Diesel			CO_2e							BACT-PSD	7/30/2018
IL-0130	IL	Jackson Energy Center	Firewater Pump Engine	Ultra-low Sulfur Diesel	420	HP	CO_2e		241	TPY	12-MONTH ROLLING AVERAGE			BACT-PSD	12/31/2018
IL-0133	IL	Lincoln Land Energy Center	Fire Water Pump Engine	Ultra-low Sulfur Diesel	320	HP	CO_2e		92	TPY				BACT-PSD	7/29/2022
LA-0309	LA	Benteler Steel Tube Facility	Firewater Pump Engines	Diesel	288	HP	CO_2e							BACT-PSD	6/4/2015
LA-0314	LA	Indorama Lake Charles Facility	Six (6) Diesel Firewater Pump Engines	Diesel	425	HP	CO_2e							BACT-PSD	8/3/2016
LA-0316	LA	Cameron LNG Facility	Eight (8) Firewater Pump Engines	Diesel	460	HP	CO_2e	Good combustion practices.						BACT-PSD	2/17/2017
LA-0384	LA	Direct Reduced Iron Facility	Internal Combustion Engines	Diesel			CO_2e	Compliance with 40 CFR 60 Subpart IIII.						BACT-PSD	6/13/2019
LA-0386	LA	LaSalle Bioenergy LLC	Generators and Firewater Pumps Engines	Diesel			CO_2e	Compliance with 40 CFR 60 Subpart IIII.						BACT-PSD	5/5/2021
OH-0383	OH	Petmin USA Incorporated	Black Start Generator (P007)	Diesel	158	HP	CO_2e	Good combustion practices; meets EPA Tier 4 requirements in 40 CFR 60 Subpart IIII.	9.09	TPY				BACT-PSD	7/17/2020
TX-0758	TX	Ector County Energy Center	Firewater Pump Engine	Diesel			CO_2e		5	TPY	ROLLING TOTAL			BACT-PSD	8/1/2014
VA-0325	VA	Greensville Power Station	Diesel-Fired Water Pump	Ultra-low Sulfur Diesel	376	BHP	CO_2e	Good combustion and maintenance practices.	104	TPY	ROLLING TOTAL			N/A	6/17/2016

Economic Feasibility Assessment – Selective Catalytic Reduction for Natural Gas Engines

Selective Catalytic Reduction (SCR) Economic Feasibility Assessment For Capital Cost

Capital Cost Summary		Capital Cost
DIRECT COSTS		
PURCHASED EQUIPMENT COST (PEC)[1]	**PEC =**	**$365,701**
(1) Purchased Equipment		
(a) Total Equipment[2]		**$297,318**
(b) Instrumentation (0.1 x [1a])		**$29,732**
(c) Sales Taxes (0.03 x [1a])		**$8,920**
(d) Freight (0.1 x [1a])		**$29,732**
TOTAL DIRECT CAPITAL COST (DCC)[3]	**DCC =**	**$365,701**
INDIRECT COSTS[4]		
Engineering (50% of PEC)		$182,851
General Facilities (5% of PEC)		$18,285
Process Contingency (5% of PEC)		$18,285
TOTAL INDIRECT CAPITAL COST (ICC)	**ICC =**	**$219,421**
PROJECT CONTINGENCY (30% of ICC + DCC) (PC)[4]	**PC =**	**$175,537**
OTHER PREPRODUCTION COSTS		
Preproduction Cost (2% of (DCC+ ICC + PC))		$15,213
TOTAL CAPITAL INVESTMENT (TCI = DC + IC + PC)	**TCI =**	**$775,872**

1. Freight, sales tax, and instrumentation cost from Table 2.4 of U.S. EPA Air Pollution Control Cost Manual (APCCM), Section 1, Chapter 2, "Cost Estimation: Concepts and Methodology", Seventh Edition, November 2017.

2. Based on March 21, 2023 estimate obtained by Miratech.

3. Direct installation costs included in total equipment estimate.

4. Table 2.5 of U.S. EPA APCCM, Section 4.2, Chapter 2, "Selective Catalytic Reduction," Sixth Edition, October 2000. Added additional engineering and contingency cost because of unknonws associated with unique implementation of technology on platform in Gulf of Mexico and need for redesign of platform to accommodate equipment associated with SCR control technology due to limited spacing availability.

Selective Catalytic Reduction (SCR) Economic Feasibility Assessment For Annual Cost

Annual Cost Summary			Annual Cost
DIRECT ANNUAL COSTS			
OPERATION AND MAINTENANCE[1]			
Maintenance (0.5% of TCI)			$3,879
REAGENT			
Requirement[2]	4.47 lb/hr at	$558.49 per ton[3]	$10,935
Delivery Costs	100% of reagent costs		$10,935
CATALYST[1]			
Catalyst Replacement[4]			$6,054
Delivery Costs	150% of replacement costs		$9,081
Catalyst Life (years)			3
Annual Interest Rate (%)			7%
Future Worth Factor			0.381
Total Annual Catalyst Replacement Cost			$5,767
UTILITIES[5]			
Electricity	9.6 kW	$ 0.1020 per kW-hr	$8,564
TOTAL DIRECT ANNUAL COSTS (DAC)		**DAC =**	**$40,081**
INDIRECT OPERATING COSTS[1,6]			
Administrative Charges (3% of (Operator Cost + 0.4 x Annual Maintenance Cost)			$1,278
Capital Recovery (CRF x TCI)			
10 years @	7.00% interest	CRF[7] = 0.1424	$110,467
TOTAL INDIRECT ANNUAL COSTS (IAC)		**IAC =**	**$111,745**
TOTAL ANNUALIZED COST (TAC = DAC + IAC)		**TAC=**	**$151,826**
Cost Effectiveness Summary			
Annual Control Cost ($)			**$151,826**
Pollutant to be Removed [NO_X] (tpy)[8]			**5.62**
CONTROL COST EFFECTIVENESS ($/ton)			**$27,015**

1. U.S. EPA APCCM, Section 4, Chapter 2, "Selective Catalytic Reduction," Seventh Edition, June 2019.
2. Reagent (urea) flow rate based on March 21, 2023 estimate obtained by Miratech.

3. Reagent cost taken from Appendix A.2.3 of U.S. EPA's *Petroleum Refinery Tier 2 BACT Analysis Report* dated January 16, 2001 (available at: https://archive.epa.gov/airquality/ttnnsr01/web/pdf/bactrpt.pdf). The $300/ton reagent cost from this document was corrected for inflation to 2023 dollars.
4. SCR catalyst cost from J. Edward Chichanowicz, "Current Capital Cost and Cost Effectiveness of Power Plant Emissions Control Technologies", January 2010. The $5,000/m^3 catalyst cost from this document was corrected for inflation to 2023 dollars.
5. Based on Equations 2.48 and 2.49 in U.S. EPA APCCM, Section 4.2, Chapter 2, "Selective Catalytic Reduction," Sixth Edition, October 2000. Assumes a duct pressure drop of 8 inches of water, catalyst pressure drop of 1 inches of water, and 2 catalyst layers. Electricity price based on FL average retail price in Jan. 2023 for the industrial sector. (available at: http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a)
6. Bureau of Labor Statistics, National Occupational Employment and Wage Estimates – United States, March 2023 (Stats last updated May 2021). Hourly rates for operators based on project-specific estimates.

   Operating Labor Cost = 8,760 hours of Operation/Labor = 0.5 hours/shift × Labor Rate ($75.00/hr) × (Operating Hours/8 hours/shift)
7. Interest rate conservatively set at 7.00%, based on EPA's seven percent social interest rate from the U.S. EPA APCCM, Section 1, Chapter 2, "Cost Estimation: Concepts and Methodology," Sixth Edition, January 2002.
8. SCR catalyst assumed to achieve 50% reduction in NO_X emissions, per March 21, 2023 estimate provided by Miratech.

APPENDIX E. MAINTENANCE ALLOWANCE APPLICATION PER 40 CFR § 63.562(B)(6)

In accordance with the *Maintenance allowance for loading berths* at 40 CFR § 63.562(b)(6), Blue Marlin Offshore Port, LLC (BMOP) is applying to the U.S. Environmental Protection Agency (EPA) for approval for a maintenance allowance for the BMOP DWP loading berths based on annual marine tank vessel loading operation time for commodities not exempted in § 63.560(d).

Maintenance Allowance Provision

40 CFR 63 Subpart Y – *National Emission Standards for Marine Tank Vessel Loading Operations* provides for a maintenance allowance, defined at § 63.561 as "a period of time that an affected source is allowed to perform maintenance on the loading berth without controlling emissions from marine tank vessel loading operations." BMOP is requesting authorization for a maintenance allowance at the proposed deepwater port (DWP) of up to 629 hours per calendar year to perform maintenance on the loading berths without controlling emissions from marine tank vessel loading operations. It should be noted that EPA has already approved a maintenance allowance for the Valdez Marine Terminal (VMT) source of a maximum of 40 calendar days per calendar year where the use of the loading berths are not required to be equipped with a vapor collection system and control device.[117] 40 calendar days is equal to 960 hours per year. BMOP is requesting a maintenance allowance approximately one third lower.

A comment on the proposed Subpart Y rulemaking noted that a maintenance allowance should be added to the rule for "when facilities need to conduct repairs to the loading berth or vapor control systems or are faced with unique compliance circumstances not otherwise addressed in this regulation." The commenter continued that the maintenance allowance would allow "facilities to continue operations, either at the berth being repaired or, on a limited basis, at a stand-by berth at the facility not equipped with vapor controls."[118] In the response to comment, EPA stated their agreement with this suggestion, and thus added the maintenance allowance provision to the final rule.

BMOP's proposed DWP certainly presents unique compliance circumstances not otherwise addressed in Subpart Y, given the distance from shore, the distance from the vessel to the platform-based vapor control system, as well as many other factors specific to CALM buoy loading offshore that have previously been documented as part of the BMOP application submittals.

Known Vapor Combustion System Reliability In the Unique Context of the Project

In consideration of anticipated maintenance challenges that could impact the BMOP vapor capture and control system added to the Project design to address EPA's applicability of Subpart Y, BMOP has reviewed prior considerations made when assessing the reliability and availability of vapor combustion units (VCUs) in a unique offshore setting at WC 509.

[117] 40 CFR § 63.562(d)(2)(ii)(B).

[118] United States Environmental Protection Agency, *Federal Standards for Marine Tank Vessel Loading Operations and National Emission Standards for Hazardous Air Pollutants for Marine Tank Vessel Loading Operations, Technical Support Document for Final Standards: Summary of Public Comments and Responses*, EPA-453/R-95-014, July 1995, Page 2-120.

[redacted]

[redacted]

[redacted]

[redacted]

In total, BMOP estimates 629 hours of unavailability of the vapor capture and control system due to known VCU downtime as a result of unplanned issues. [redacted]

With an offshore facility, the distance between the VCU's and loading docks is larger and more complex than that of an onshore facility. [redacted] At the proposed location, the vapor combustion would be located over a mile away (thousands of feet) from the collection point on the very large crude carriers (VLCCs). The distance is required in a marine setting with large VLCCs to maintain required safety distances for mooring and unloading operations. In addition, vapor collection lines would have to traverse down to the sea floor and back up to the VCU platform, adding another degree of complication. This greatly increases the number of potential failure points throughout the vapor capture system. Each additional potential failure point would theoretically add to the potential downtime of the system as it not only increases the amount of failure points possible, but it also would increase the time required to diagnose failures as they occur. A further complication of the offshore system is that a vast majority of the vapor

collection system would be located underwater at the sea floor. If maintenance is required at an underwater location, the time to repair would be increased exponentially compared to an onshore location where the entirety of the system can be accessed and repaired on foot. Even if maintenance were required for an above-water component, navigating to and from the location on a boat, rather than by a car or walking, would add additional downtime. In other words, an inconsequential unplanned failure of a VCU system onshore can be corrected in ~ 1 hour that might take days to resolve in the proposed Project location.

With the known reliability of VCU systems at onshore terminals adapted to the specific context of the BMOP Project location and design, a maintenance allowance is needed for the vapor capture and control system at the proposed BMOP DWP. For situations when loading a very large crude carrier has commenced at the DWP, and an unplanned issue arises with the vapor capture and control system, it is not always practical to stop loading and wait for a repair, which could take days to complete in the offshore location. Accordingly, BMOP is applying for a maintenance allowance of 629 hours per calendar year to perform maintenance on the loading berths without controlling emissions in a VCU from continuing marine tank vessel loading operations.

Considerations per 40 CFR § 63.562(b)(6)

The following provides discussion for the EPA's consideration in approving the maintenance allowance, as delineated at § 63.562(b)(6).

> *(i) The owner or operator expects to be in violation of the emissions standards due to maintenance;*

During an unplanned failure of the vapor capture and control system, BMOP will not be able to reduce HAP emissions from marine tank vessel loading operations by 95 weight-percent during maintenance of the VCUs, as would be required under § 63.562(b)(4) if a maintenance allowance is not approved. For example, if the remote transmitter has failed, the DWP will not be able to safely load and recover vapors through the vapor capture system. BMOP will continue to mitigate loading emissions by use of submerged fill during the maintenance allowance.

> *(ii) Due to conditions beyond the reasonable control of the owner or operator, compliance with the emissions standards during maintenance would result in unreasonable economic hardship;*

An unplanned failure that ceases loading will result in demurrage fees, as well as longer loading times and increased outage duration. The capital recovery for the entire project would be reduced, resulting in opportunity cost and increased interest form longer project funding payback. Simply considering the outage costs for 629 hours without loading with a VLCC moored at a CALM buoy at the proposed DWP, the Project would be impacted by $50,320,000 per year. This is an unreasonable economic impact to the Project.

> *(iii) The economic hardship cannot be justified by the resulting air quality benefit;*

The total potential HAP emissions from the DWP during 629 hours of loading without capture and control is 80.2 tons. Considering only the outage costs, the economic impact is $627,181.42 per ton of HAP.

EPA has previously evaluated the cost effectiveness for vapor capture and control of marine vessels. In the consideration of requiring a beyond-the-floor standard in the Subpart Y residual risk and technology review

completed in 2011, EPA determined that costs of $485,000 per ton of HAP for offshore vapor recovery were not reasonable.[119]

> *We agree with commenters that these costs are unreasonable.*[120]

A much higher cost is also unreasonable and cannot justify the economic hardship.

> *(iv) The owner or operator has given due consideration to curtailing marine vessel loading operations during maintenance;*

Curtailing marine vessel loading for a moored vessel has been given due consideration, but as described previously, the outage costs with a VLCC moored to a CALM buoy without loading is too great an economic hardship.

> *(v) During the maintenance allowance, the owner or operator will endeavor to reduce emissions from other loading berths that are controlled as well as from the loading berth the owner or operator is seeking the maintenance allowance; and*

BMOP will only load one vessel at a time. Accordingly, BMOP will not have emissions from loading at the other CALM buoy when utilizing the maintenance allowance.

> *(vi) During the maintenance allowance, the owner or operator will monitor and report emissions from the loading berth to which the maintenance allowance applies.*

BMOP will monitor all operations utilizing the maintenance allowance and will report emissions accordingly. Emissions from loading will continue to be mitigated by submerged fill during the maintenance allowance.

[119] Letter from J.D. Bellows, Chevron Corporation, to Mr. David W. Markwordt, U.S. EPA, "Technical Choices for Marine Vapor Controls on Loading Operations at Offshore Terminals, July 21, 1993, IV-D-136 of Docket A-90-44.

[120] 76 FR 22581, April 21, 2011.

PREVENTION OF SIGNIFICANT DETERIORATION AIR CONSTRUCTION PERMIT APPLICATION

Volume 2: PSD and Toxics Air Quality Dispersion Modeling Report

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TABLE OF CONTENTS

1. INTRODUCTION **1-1**

2. PROJECT BACKGROUND **2-1**

2.1 Offshore Facilities **2-1**

2.2 Offshore Operations Ambient Boundary **2-2**

3. REGULATORY APPLICABILITY FOR MODELING **3-1**

3.1 Prevention of Significant Deterioration **3-1**

3.1.1 Special Considerations for VOC and $PM_{2.5}$ *3-2*

3.1.2 Additional Impacts Analyses *3-2*

3.2 Louisiana Toxics Program **3-2**

4. PSD MODELING METHODOLOGY **4-1**

4.1 CLASS II PSD MODELING ANALYSES **4-1**

4.1.1 Special Considerations for NO_2 ..... *4-4*

4.1.2 Significance Analysis *4-5*

4.1.3 Area of Impact (AOI) Analysis *4-5*

4.1.4 Significant Monitoring Concentrations *4-6*

4.1.5 NAAQS Analysis *4-6*

4.1.6 PSD Increment Analysis *4-7*

4.1.7 Secondary $PM_{2.5}$ and Ozone Impact Analysis *4-7*

5. CLASS II AREA AIR DISPERSION MODELING ANALYSES **5-1**

5.1 DISPERSION MODEL SELECTION **5-1**

5.2 METEOROLOGICAL DATA **5-1**

5.2.1 Data Selection and Proposed Substitution *5-2*

5.3 BACKGROUND MONITOR SELECTION **5-4**

5.4 TERRAIN ELEVATIONS **5-6**

5.5 GEP STACK HEIGHT **5-6**

5.6 BUILDING WAKE (DOWNWASH) EFFECTS **5-6**

5.7 PSD/TAPs MODELING RECEPTOR GRID **5-7**

5.8 EMISSION RATES **5-8**

5.9 SOURCE PARAMETERS **5-11**

6. OZONE AND $PM_{2.5}$ TIER I MERPS ANALYSIS **6-1**

6.1 MERPs as a Tier 1 Demonstration Tool **6-1**

6.2 Selection of MERPs U.S. EPA Hypothetical Source **6-2**

6.2.1 Physical Environment *6-2*

6.2.2 Chemical Environment *6-4*

6.3 Offshore Secondary Impacts **6-6**

6.3.1 Offshore $PM_{2.5}$ Source Impact Analysis *6-6*

6.3.2 Offshore VOC Source Impact Analysis *6-7*

6.3.3 Offshore VOC Cumulative Impact Analysis *6-8*

6.4 Onshore Secondary Impacts **6-9**

6.4.1 Onshore $PM_{2.5}$ Source Impact Analysis *6-9*

6.4.2 Onshore VOC Source Impact Analysis *6-10*

7. PSD AND TOXICS MODELING RESULTS **7-12**

7.1 PSD Dispersion Modeling Results **7-12**

7.1.1 Significance Analysis *7-12*

7.1.2 NAAQS ANALYSIS *7-13*

7.2 Toxic Modeling Results 7-13
8. ADDITIONAL IMPACT ANALYSES 8-1
8.1 GROWTH ANALYSIS 8-1
8.2 SOIL AND VEGETATION ANALYSIS 8-1
8.3 CLASS I AREA ANALYSIS 8-1
8.4 NEAR-FIELD VISIBILITY ANALYSIS 8-1
APPENDIX A. REGIONAL INVENTORY A
APPENDIX B. PSD DISPERSION CONTOURS B

LIST OF FIGURES

Figure 2-1. Proposed Platform, Buoy Locations and Safety Zone 2-4

Figure 4-1. General PSD Class II Area Modeling Flowchart 4-3

Figure 4-2. 1-Hour NO_2 AOI and Regional Inventory 4-6

Figure 5-1. Locations of Buoy 42035 and BMOP Project 5-2

Figure 5-2. Buoy 42035 Surface Data Wind Rose 5-3

Figure 5-3. Buoy 42035 Profile Data Wind Rose 5-4

Figure 5-4. Monitors in the Vicinity of the Project 5-4

Figure 5-5. PSD/TAPs Receptor Grid 5-7

Figure 5-6. Hot-Spot 1-Hour NO_2 Grid 5-8

Figure 6-1. U.S. EPA Hypothetical Sources Considered 6-3

Figure 6-2. 50 km Radius Domain for Bay (left) and Acadia (right) Hypothetical Sources 6-4

Figure 6-3. U.S. EPA Qlik Ozone Impact Versus Distance for the Bay and Acadia Hypothetical Sources (1,000 tpy and 90 m Stack Height Scenario) 6-6

LIST OF TABLES

Table 2-1. Project Location Coordinates 2-1

Table 2-2. Safety Zone Coordinates 2-2

Table 3-1. Project PSD PTE Summary 3-1

Table 4-1. Applicable Air Quality Standards – Criteria Pollutants 4-4

Table 5-1. Background Monitors 5-5

Table 5-2. Modeled Sources 5-9

Table 5-3. Stationary Point Sources 5-10

Table 5-4. Stationary Volume Sources 5-11

Table 5-5. Modeled Point Source Stack Parameters 5-12

Table 5-6. Modeled Volume Source Stack Parameters 5-12

Table 6-1. Information for U.S. EPA Hypothetical Sources Considered 6-3

Table 6-2. 2017 U.S. EPA NEI County Emissions for Acadia and Bay Hypothetical Sources 6-5

Table 7-1. PSD Significance Analysis Results 7-12

Table 7-2. PSD NAAQS Analysis Results 7-13

Table 7-3. Step 1 TAPs Modeled Concentration Results 7-14

1. INTRODUCTION

Blue Marlin Offshore Port LLC (the Applicant) is proposing to develop the Blue Marlin Offshore Port (BMOP) Project (Project) in the Gulf of Mexico (GOM) to provide United States (U.S.) crude oil loading services onto very large crude carriers (VLCCs), and other crude oil carriers, for export to the global market.

The primary purpose of the Project will be to provide a safe and reliable long-term supply of crude oil for export to the global market. To accomplish this purpose, BMOP will repurpose an existing subsea pipeline within the Stingray Pipeline System to transport crude oil to the proposed deep water port (DWP). This DWP will be located in federal waters within Outer Continental Shelf (OCS) West Cameron Lease Block (WC) 509, WC 508, and East Cameron (EC) Block 263. At the DWP location, VLCCs and other crude oil carriers (collectively referred to as "crude oil carriers" in this report), will moor at one of two Catenary Anchor Leg Mooring (CALM) Buoys, a type of Single Point Mooring (SPM) buoy system. Floating crude oil hoses will be connected to the buoy to support crude oil loading. Up to 275 VLCCs or other crude oil carriers may be loaded per year.

In response to EPA's September 13, 2022, request, BMOP has added vapor capture and control for the loading of the crude oil carriers at the proposed DWP. The vapor capture and control system will include floating vapor return hoses, which will be connected to the crude oil carriers along with the floating crude oil hoses. Displaced vapors from the crude oil carrier will be routed through the floating vapor return hoses back to the CALM buoys. Separate submerged hoses will carry the vapors from the buoys to the pipeline end manifold (PLEM) at the sea floor, and a looped subsea vapor return pipeline will route the vapors from the PLEMs back to the WC 509 Platform Complex. A dock safety skid and vapor blowers will be added to the WC 509 Platform Complex. The captured vapors (expected 99% capture efficiency) will be routed to three (3) vapor combustion units (VCUs), which will have an average destruction and removal efficiency (DRE) for volatile organic compounds (VOCs) of 95%, during routine loading operations.

This revised air dispersion modeling report is being provided to EPA to present the updates to the air quality impact assessment performed to represent the new DWP project design for the revised PSD air permit application submittal. This report, Volume 2 of the PSD application, includes the air quality impact assessment in accordance with 40 CFR §52.21(n)(1) and the source impact analysis required under 40 CFR §52.21(k).

BMOP has performed dispersion modeling to meet applicable requirements under the PSD program and Louisiana Department of Environmental Quality (LDEQ) Air Toxics Program. BMOP has also performed a revised cumulative impact assessment to meet applicable ambient air quality requirements under the National Environmental Policy Act (NEPA) regulations to support the DWPL application pending before USCG and MARAD. The NEPA assessment is being submitted separately in the MARAD filing.

Trinity Consultants Inc. (Trinity) has assisted BMOP in preparing the revised PSD permit application and associated air dispersion modeling analysis for the DWP. On behalf of BMOP, Trinity submitted an air dispersion modeling protocol in February 2023 to obtain EPA Region 6 approval on the various changes being proposed as part of this application. After a follow-up discussion[1] of the protocol with EPA Region 6, Trinity incorporated EPA Region 6 comments and prepared this air dispersion modeling report to outline the methodology used to perform the air dispersion modeling analyses for the proposed project. An alternative modeling request for use of AERCOARE was provided under separate cover to EPA on January 26, 2021. An

[1] Conference call between Energy Transfer, EPA Region 6, and Trinity on February 14, 2023.

updated alternative modeling request will be provided to EPA for this project under separate cover. This modeling report includes a brief description of the federal and state regulations applicable to the proposed project that trigger air dispersion modeling, an overview of the proposed modeling software, and a description of the methodology proposed used in each modeling analysis specific to the DWP portion of the proposed project. This report also demonstrates that the modeled impacts from the offshore portion of the project do not result in a violation of the National Ambient Air Quality Standards (NAAQS), PSD increments, or the LDEQ Ambient Air Standards (AAS) for Hazardous Air Pollutants (HAPs) and Toxic Air Pollutants (TAPs).

2. PROJECT BACKGROUND

The proposed Project utilizes many existing facilities, both onshore and offshore. Crude oil for export at BMOP will be transported out of the existing Energy Transfer Nederland Terminal, LLC terminal and storage facility in Jefferson County, Texas (Nederland Terminal or NT). This terminal is connected to multiple crude oil pipelines from across the U.S. In addition, an affiliate of the Applicant owns the Stingray Pipeline System (Stingray) and has confirmed that its existing subsea pipeline and offshore platforms are suitable for conversion to facilitate crude oil export from a DWP in the northern GOM.

Crude oil will be routed from the NT pump station through a new 42-inch outer diameter (OD) onshore pipeline to the existing Stingray Mainline at the existing Station 501, and from there through the existing 36" OD Stingray Mainline to the existing offshore platform complex at WC 509.

2.1 Offshore Facilities

The DWP will be located in federal waters within and adjacent to the OCS in WC 509, WC 508, and EC 263. The DWP will be approximately 82 statute miles off the coast of Cameron Parish, Louisiana, with an approximate water depth of 162 feet.[2] The crude oil will be metered at the pump station at the NT and on the existing WC 509B Platform and routed through two Crude Oil Loading Lines to PLEMs located on the seafloor below two CALM buoys located in WC 508 and in EC 263. From each PLEM, the crude oil will be routed to its respective floating CALM buoy through submerged flexible hoses. Crude oil carriers will moor at a CALM buoy, retrieve and connect the floating crude oil hoses connected to the CALM buoy and the crude oil will then route from the buoy to the crude oil carriers for loading. Up to 275 VLCCs or other crude oil carriers will load per year. For the modeling purposes described in this air quality modeling report, BMOP has utilized the most conservative coordinate of the WC509 lease block, provided below in Table 2-1.

Following EPA's September 13, 2022, letter, BMOP has revised the Project design to include vapor capture and control with VCUs. Two CALM buoys will be placed approximately 1 mile from the platform structures and connected via vapor return lines and liquid crude lines to the platforms. Vessels will be moored to one of two buoys via mooring hawsers. Floating hoses will extend from the buoys to the moored vessel to allow for the loading of crude oil and capture of displaced vapor. The approximate coordinates for the platform complex and the buoys are included below.

Table 2-1. Project Location Coordinates

Component	Latitude (N)	Longitude (W)
WC 509 Complex	28° 26′ 00.01″	93° 00′ 15.23″
Calm Buoy No. 1	28° 27′ 03.29″	93° 00′ 12.33″
Calm Buoy No. 2	28° 26′ 34.37″	92° 59′ 19.21″

As defined in the 1974 DWPA, and revised in 2012, a DWP is "any fixed or floating manmade structure other than a vessel, or any group of such structures, that are located beyond State seaward boundaries and that are used or intended for use as a port or terminal for the transportation, storage, or further handling of oil or natural gas for transportation to or from any State…".

Based on the definition above, BMOP considers the following operations as part of the DWP project:

[2] The DWP will be approximately 99 statute miles from where the pipe leaves the shore, also in Cameron Parish, Louisiana.

- Marine loading of crude oil;
  - Uncaptured crude oil loading vapors;
  - Captured crude oil loading vapors controlled by VCUs;
  - Captured crude oil loading vapors controlled by a low pressure flare during vapor pipeline pigging;
- Supporting platform operations;
  - Reciprocating internal combustion engines (ICE) for providing power to the platform and platform cranes; and
  - Storage vessels and piping components on the WC 509 Platform Complex.

Emissions from those operations that meet the PSD definition of stationary source are the subject of the PSD and LDEQ Air Toxic Program modeling analyses.

2.2 Offshore Operations Ambient Boundary

As the proposed operations are performed in deep water ~80 miles offshore in the Gulf of Mexico, there is no physical fenceline around the project. The regulations governing the establishment of safety zones on the outer continental shelf (OCS) are located in 33 CFR Part 147. A safety zone, for the purpose of ports and waterways safety, is also defined in 33 CFR Part 165. Per 33 CFR 165.20, a safety zone is a water area, shore area, or water and shore area to which, for safety or environmental purposes, access is limited to authorized persons, vehicles, or vessels. To determine an appropriate safety zone for the project, BMOP considered the operational area specific to the proposed DWP. The operational boundary of the project will be defined as a No Anchorage Area (NAA) due to the extensive amount of subsea infrastructure and associated BMOP equipment within the proposed area. The NAA will be marked by private lighted buoys at the four (4) distinct corners of the safety zone, as described in the table below. Access to the operational area of the project will be limited to authorized persons and vessels and will be monitored by BMOP.

Table 2-2. Safety Zone Coordinates

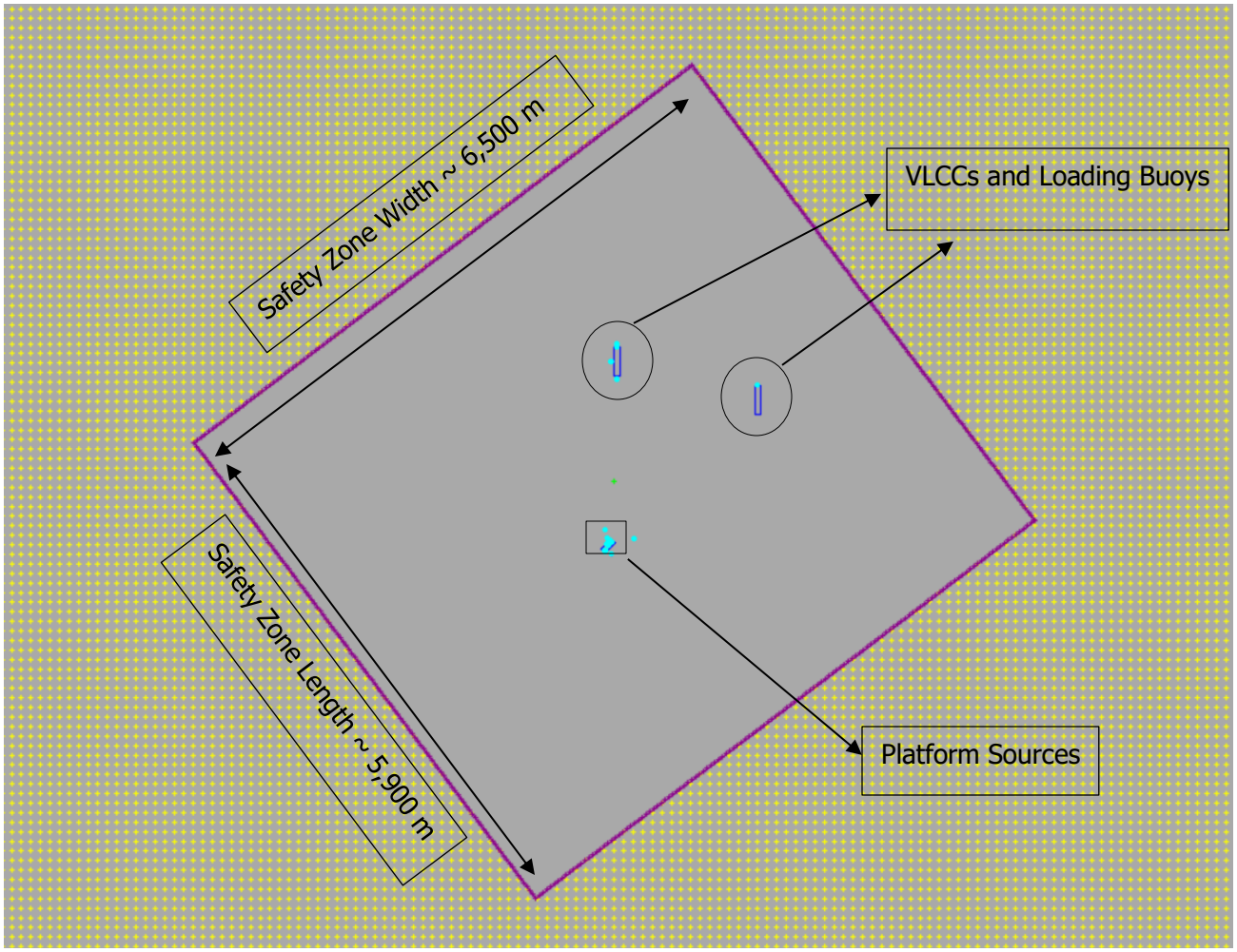
Safety Zone Buoy Location	Latitude	Longitude
North Corner	28° 28′ 41.76″	92° 59′ 44.41″
East Corner	28° 26′ 07.13″	92° 57′ 32.72″
South Corner	28° 23' 58.81"	93° 00' 44.53"
West Corner	28° 26' 33.47"	93° 02' 55.90"

These buoy locations are consistent with the operational requirements of the DWP, including the existing, nearby shipping lane, the proposed vessel arrival and departure corridor, and the location of the DWP, buoys, and anchorage areas. The proposed project safety zone corresponds to the U.S. Coast Guard's safety exclusion zone since BMOP has considered relevant safety factors (e.g., the locations of BMOP equipment with the operational area, the locations of subsea infrastructure, and vessel traffic). Additionally, the identified area meets the definition of a safety zone per 33 CFR 165.20, since the area will be limited to only authorized persons and vessels.

The modeling analysis utilizes the proposed safety zone for this project as the ambient air boundary.[3] The following figure shows the platform emissions sources, loading buoys, as well as the proposed safety zone that is treated as the modeled project boundary.

[3] Per EPA guidance, *It should be noted that the term "fence line" for modeling purposes generally makes reference to a source's property boundary and may not refer literally to the existence of a fence at such boundary. The EPA's "ambient air" policy does not mandate that public access to a source's property be precluded by a fence; other measures that effectively preclude public access may be approved for establishing an ambient air exclusion for PSD modeling purposes (*direct quote from the EPA *July 2022 Guidance for Ozone and Fine Particulate Matter Modeling).* EPA's revised ambient air policy is outlined in the December 2019 *Revised Policy on Exclusions from "Ambient Air".*

Figure 2-1. Proposed Platform, Buoy Locations and Safety Zone



3. REGULATORY APPLICABILITY FOR MODELING

The proposed DWP is subject to the following federal and state air quality regulations, for which an air dispersion modeling analysis may be necessary.

3.1 Prevention of Significant Deterioration

BMOP has performed an air quality dispersion modeling analysis to comply with the requirements of Part C of Title I of the Clean Air Act, 42 U.S.C. §§7470-7492, the statutory basis for the PSD program. The EPA has codified PSD definitions, applicability, and requirements in 40 CFR Part 52.21. PSD is one component of the NSR permitting program applicable in areas that are designated in attainment of the NAAQS. The DWP will be approximately 80 miles from the nearest point on land in Cameron Parish, Louisiana. Cameron Parish is designated by the EPA as "attainment" or "unclassifiable" with the NAAQS for all criteria pollutants.[4] Therefore, the project is not subject to nonattainment New Source Review (NNSR) permitting requirements for any criteria pollutants. LDEQ has an approved PSD program at LAC 33:III.509.

Under PSD permitting rules, the major source threshold is 250 tons per year (tpy), unless the facility is listed specifically in 40 CFR Section (§) 52.21(b)(1)(i)(a) as having a lower 100 tpy threshold. The project is not included on the list of operations subject to the more stringent 100 tpy threshold. As such, the project is subject to PSD permitting should emissions from the project exceed the major source threshold of 250 tpy of any regulated pollutant. Based on the potential-to-emit (PTE) calculations included in this application, the proposed project will exceed the PSD major source threshold of 250 tons per year (tpy) for oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOC). In addition, the Project results in both a significant emissions increase and a significant net emissions increase that exceeds the significant emission rates (SER) for PM_{10} and $PM_{2.5}$ (and GHG, though GHG does not require an air dispersion modeling assessment).[5] Therefore, the PSD modeling analysis includes each of these pollutants to demonstrate that the proposed project will not cause or contribute to air pollution in violation of the NAAQS or PSD increment thresholds. The table below summarizes the PTE of the relevant PSD pollutants compared to the major source threshold and SER defined in 40 CFR 52.21(b). See Volume I of the PSD air construction permit application for additional details.

Table 3-1. Project PSD PTE Summary

Pollutant	Major Source Threshold (tpy)	Significant Emissions Rate (tpy)	Potential to Emit (tpy)	PSD Air Quality Impacts Analysis Required?
NO_X	100	40	449.78	Yes
CO	100	100	817.25	Yes
VOC	100	40	2,473	Yes
SO_2	100	40	14.35	No
PM_{10}	100	15	16.00	Yes
$PM_{2.5}$	100	10	16.00	Yes
H_2S	100	10	1.04	No
H_2SO_4	100	7	0.05	No
CO_2e	75,000	75,000	494,797	Yes

[4] 40 CFR §81.319

[5] Carbon dioxide equivalents (CO_2e) are subject to a different major source threshold (75,000 tpy) for PSD major sources per 40 CFR 52.21(b)(49). The proposed project also triggers PSD for CO_2e but there are no applicable modeling standards.

3.1.1 Special Considerations for VOC and $PM_{2.5}$

As provided in 40 CFR Part 50, VOC does not have a specific ambient air quality standard but is considered a precursor to ozone emissions. Per 40 CFR §50.10, the 8-hour ambient air quality standards for ozone apply to the Project. As such, BMOP has evaluated the air quality impacts from the Project by performing a Tier I Modeled Emission Rates for Precursors (MERPS) analysis for ozone to demonstrate that the Project will not result in a violation of the NAAQS for ozone. This report provides a detailed description of the analysis methodology and approach and demonstrates that direct impacts from the offshore portion of the Project do not result in a violation of the NAAQS.

Similarly, a MERPs analysis for $PM_{2.5}$ has also been performed to estimate the secondary impacts from $PM_{2.5}$ precursor emissions (NOx and SO_2). This analysis further describes how the modeled impact from the primary $PM_{2.5}$ emissions combined with the calculated secondary $PM_{2.5}$ impacts from the MERPs analysis do not violate the corresponding NAAQS for $PM_{2.5}$. The detailed calculations are included in Section 6 of this application.

3.1.2 Additional Impacts Analyses

BMOP has addressed the applicability of the following impact analyses in Section 8 of this modeling report:

- Growth analysis;
- Soil and vegetation analysis;
- Class I analyses; and
- Visibility analysis. y

3.2 Louisiana Toxics Program

BMOP anticipates HAPs and TAPs to be emitted during the loading operations of the proposed project. As discussed in Volume I of the PSD air construction permit application, the nearest onshore County/Parish to the Project is Cameron Parish, Louisiana. Therefore, the project must demonstrate compliance with all applicable Louisiana specific air quality rules and regulations. Specifically, the LDEQ defines the AAS in LAC 33:III Chapter 51. Each project subject to this chapter of the administrative code must comply with the corresponding AAS for HAPs and TAPs emitted from the project. TAPs are pollutants that are known or suspected carcinogens or have the potential to cause other serious health effects. LDEQ has defined TAPs to include all federally defined hazardous air pollutants (HAP) and included 13 additional pollutants that LDEQ has determined meet the criteria of a TAP. The TAPs are categorized into the following three (3) classes based on the toxic effects:

- Class I – known and probably human carcinogens;
- Class II – Suspected human carcinogens and known or suspected human reproductive toxins; and
- Class III – Acute and chronic (non-carcinogenic) toxins.

Per LAC 33:III Chapter 51, a major source has the potential to emit 10 tpy of a single TAP or 25 tpy of total TAPs. The proposed DWP project will exceed the 25 tpy threshold for total HAPs, and the single TAP threshold of 10 tpy for Hexane, Benzene, and Toluene.

Per LAC 33:III Chapter 51.5105.B.3(a), emissions from the combustion of Group 1 virgin fossil fuels (which include natural gas and diesel fuel) are exempt from meeting the requirements for the TAPs AAS requirements. As such, TAP emissions from combustion sources (e.g., VCUs, flares, natural gas generators, crane engines, firewater pumps, etc.) have not been included in the analysis.

To simplify the TAPs analysis performed for the Project, BMOP utilized the following methodology for determining the PTE of TAPs from applicable Project sources:
The annual VOC emissions (in tpy) from all direct Project sources were conservatively totaled (which includes a relatively small amount of VOC emissions from exempt combustion sources):

- Since emissions from crude oil loading make up the majority of total VOC emissions on a maximum hourly and annual average basis, the total VOC emissions were speciated according to the maximum vapor concentration of the TAPs in crude oil; and
- Annual H_2S emissions from all direct Project sources were totaled.

BMOP has evaluated the air quality and source impacts from the Project to demonstrate compliance with the Louisiana specific TAP Emissions Control Program. The following report provides a detailed description of the air quality dispersion modeling methodology, analyses, and approach, and demonstrates that direct impacts from the offshore portion of the Project do not result in a violation of the LDEQ ambient air standards for TAPs under the Comprehensive TAP Emission Control Program

Emissions of some HAPs/TAPs are anticipated to exceed the Minimum Emission Rates (MERs) codified in Table 51.1 of Title 33, Chapter 51, the Comprehensive Toxic Air Pollutant Emission Control Program, of the LAC. Therefore, BMOP has performed air quality dispersion modeling for speciated HAPs/TAPs from the proposed DWP operations to demonstrate compliance against the applicable thresholds in Table 51.2 and Table 51.3 of LAC 33:III.5111.B.5.

4. PSD MODELING METHODOLOGY

The dispersion modeling analyses has been conducted in consideration of the following guidance documents:

- Guideline on *Air Quality Models*, 40 CFR 51, Appendix W (EPA, Jan. 17, 2017)
- User's Guide for the AMS/EPA Regulatory Model – AERMOD, (EPA, June 2022)
- AERMOD Implementation Guide (EPA, June 2022)
- New Source Review Workshop Manual (EPA, Draft, Oct.1990)
- Modeling Procedures for Demonstrating Compliance with $PM_{2.5}$ NAAQS (EPA, Memorandum from Mr. Stephen Page, Mar. 23, 2010)
- LDEQ's Air Quality Modeling Procedures Document (LDEQ, Aug. 2006)
- Screening Procedures for Estimating the Air Quality Impact of Stationary Sources Revised (EPA, Oct. 1992)
- Guidance for $PM_{2.5}$ Permit Modeling (EPA, Memorandum from Mr. Stephen Page, May 20, 2014)
- Guidance for Ozone and Fine Particulate Matter Permit Modeling (EPA, Memorandum from Mr. Richard Wayland, July 29, 2022)
- Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier I Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program (EPA, Memorandum from Mr. Richard A Wayland, Apr. 30, 2019)
- Guidance on Significant Impact Levels for Ozone and Fine Particles in the Prevention of Significant Deterioration Permitting Program (EPA Memorandum from Mr. Peter Tsirigotis, Apr. 17, 2018)
- Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO_2 National Ambient Air Quality Standard (EPA, Memorandum from Mr. Tyler Fox, Mar. 1, 2011); and
- Clarification on the Use of AERMOD Dispersion Modeling for Demonstrating Compliance with the NO_2 National Ambient Air Quality Standard (EPA, Memorandum from Mr. R. Chris Owen and Mr. Roger Brode, Sept. 30, 2014)
- Bureau of Ocean Energy Management's Air Dispersion Modeling Guidelines for the Gulf of Mexico, August 2019
- EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011)
- Federal Land Managers AQRV Workgroup (FLAG) Phase I Report (October 2010)
- Revised Policy on Exclusions from Ambient Air (EPA, Memorandum from Andrew R. Wheeler, December 2, 2019).

4.1 CLASS II PSD MODELING ANALYSES

The three main steps of the standard PSD Class II area air quality modeling analysis are the Significance analysis, the NAAQS analysis, and the PSD Increment analysis. The NAAQS and PSD Increment analyses are also commonly referred to together as a "full-impact" or "cumulative" analysis. Per the January 2017 Guideline on Air Quality Models (GAQM),[6] the Significance analysis considers the emissions associated *only* with the proposed DWP to determine if it will have a significant impact upon the surrounding area. For all applicable pollutants and their respective averaging periods, the modeled maximum ground-level concentrations are compared to the corresponding Significant Impact Levels (SILs) to determine if any predicted concentrations at any receptor locations are "significant". If predicted impacts for a particular pollutant-averaging period are below the applicable SIL(s), then the project is determined not to cause or

[6] www.epa.gov/sites/default/files/2020-09/documents/appw_17.pdf

contribution to a violation of the NAAQS or PSD increment for that pollutant-averaging period and no further analyses (i.e., NAAQS and PSD increment analyses) are required for that pollutant-averaging period.

If the Significance analysis reveals that maximum modeled ground-level concentrations for a particular pollutant and averaging period are greater than or equal to the applicable SIL, a full impact analysis is required for that pollutant and averaging period. A full impact analysis considers ambient background concentrations, along with emissions from regional sources and is performed at receptors with impacts greater than the SIL in the Significance analysis. A summary of the tasks performed in standard PSD Class II area air quality modeling analysis is presented in the flow chart provided as Figure 4-1.

Figure 4-1. General PSD Class II Area Modeling Flowchart

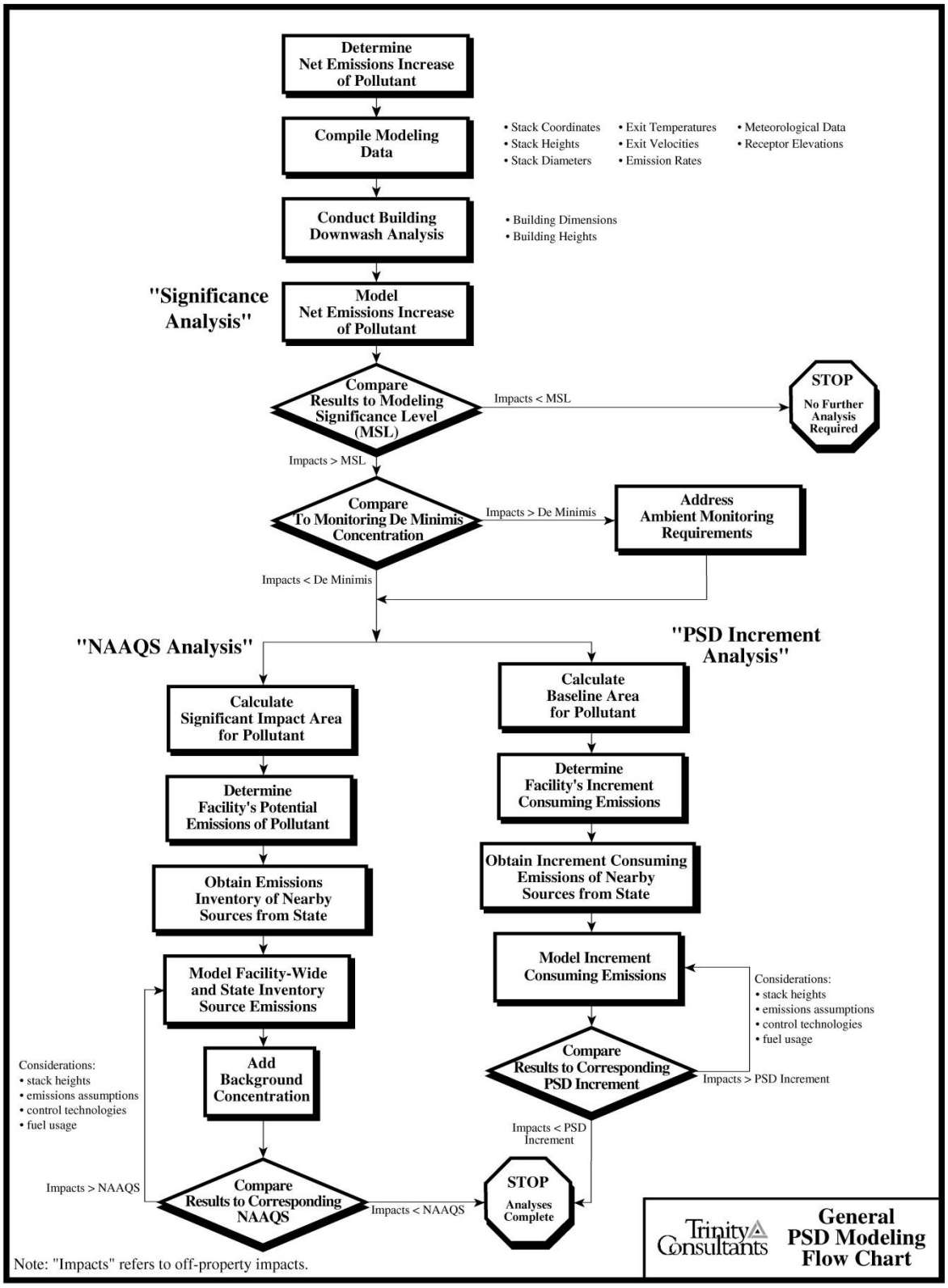


Table 4-1 lists the applicable standards for criteria pollutants that have been modeled or addressed in this report for the proposed DWP.

Table 4-1. Applicable Air Quality Standards – Criteria Pollutants

Pollutant	Averaging Period	SIL (µg/m³)	Significant Monitoring Concentration (µg/m³)	PSD Class II Increment (µg/m³)	Primary NAAQS (µg/m³)
CO	1-hour	2,000	N/A	N/A	40,000
	8-hour	500	575	N/A	10,000
NO_2	1-hour	7.5[7]	N/A	N/A	188
	Annual	1	14	25	100
O_3	8-hour	1 ppb[8]	VOC or NO_X > 100 tpy	N/A	137
PM_{10}[9]	24-Hour	5	10	30	150
	Annual	1	N/A	17	Revoked
$PM_{2.5}$	24-Hour	1.2	N/A	9	35
	Annual	0.2[10]	N/A	4	12

The highest design concentrations out of all given modeling years for each pollutant-averaging period have been compared to their respective SIL shown in the table above to determine if the ambient air impact is significant.

For 1-hour NO_2, $PM_{2.5}$, and CO modeling as well as for 8-hour CO modeling, a concatenated meteorological data set to derive the appropriate form of the NAAQS will be utilized. For annual NO_2 modeling, each individual year has been modeled separately to evaluate the maximum annual impacts.

4.1.1 Special Considerations for NO_2

Intermittent emissions sources such as emergency engines, firewater pumps, and flaring have been included in the 1-hour average NO_2 model with annualized hourly emission rates to account for the intermittent nature of operation from these sources.[11]

The modeling analysis utilizes the EPA's Tier 2 Ambient Ratio Method 2 (ARM2) option in AERMOD based on 40 CFR Part 51, Appendix W (*Guideline on Air Quality Models*) for converting modeled NO_X emission rates to modeled NO_2 impacts. The default minimum and maximum in-stack ratios of 0.5 and 0.9, respectively, have been utilized.

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[7] Based on U.S. EPA Memorandum from Stephen D. Page to Regional Air Division Directors titled, "Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program," June 29, 2010.

[8] Table 1, U.S. Environmental Protection Agency Memorandum. "Guidance on Significant Impact levels for Ozone and Fine Particles in the Prevention of Signifcant Deterioration Permitting Program". Apr. 17, 2018.

[9] EPA revoked the annual PM_{10} NAAQS in 2006 - http://www.epa.gov/ttn/naaqs/standards/pm/s_pm_history.html

[10] Table 1, U.S. Environmental Protection Agency Memorandum. "Guidance on Significant Impact levels for Ozone and Fine Particles in the Prevention of Signifcant Deterioration Permitting Program". Apr. 17, 2018. https://www.epa.gov/sites/production/files/2018-04/documents/sils_guidance_2018.pdf.

[11] Based on March 2011 EPA memo that includes guidance on intermittent sources - www.epa.gov/sites/default/files/2015-07/documents/appwno2_2.pdf. BMOP intends to utilize this guidance, where applicable.

4.1.2 Significance Analysis

As mentioned in Section 4.1, the Significance analysis (significance modeling) determines whether a full-impacts analysis (i.e., NAAQS and PSD Increment modeling) is required for compliance with 40 CFR 52.21. For each pollutant that requires PSD review, significance modeling incorporates all project sources and project-affected sources.

BMOP has only modeled the stationary sources associated with the proposed DWP project for those applicable pollutants that exceed their SER. Operations that BMOP considers indirect sources of emissions are not included as part of the PSD significance analysis. For $PM_{2.5}$, the total (primary + secondary) $PM_{2.5}$ impacts from the significance modeling have been compared against the SILs to demonstrate compliance. The significance modeling compares the maximum concentrations from the significance model results to the appropriate SILs as shown in Table 7-1.

4.1.3 Area of Impact (AOI) Analysis

An AOI analysis is performed when the results from significance modeling indicate that any of the respective SILs are exceeded. A circle is drawn around the facility that has a radius equal to the distance from the center of the facility to the furthest *significant* off-property receptor. For each pollutant, the AOI represents the greatest distance for ALL applicable averaging periods. The January 2017 GAQM[12] recommends that the calculated AOI should not exceed 50 km due to accuracy constraints of AERMOD. The AOI influences the full impact analysis in two ways:

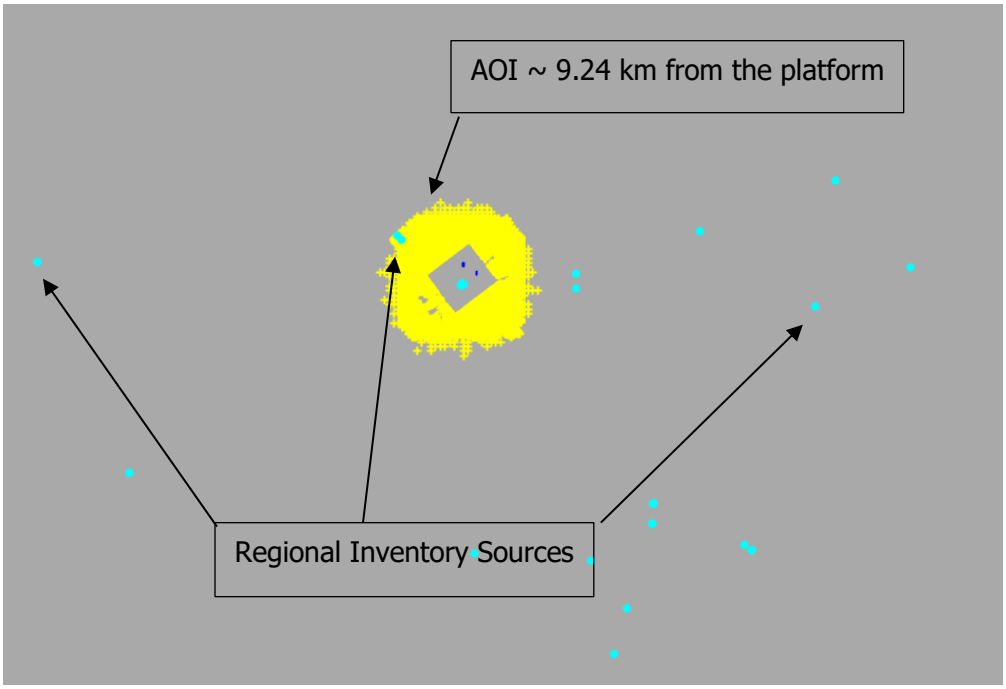
- The facility must include receptors that exceed the SIL within the AOI for NAAQS and PSD Increment modeling; and
- The facility must obtain an off-property emissions inventory from the Bureau of Ocean Energy Management (BOEM) based upon the AOI plus 20 km.

The AOI for pollutants that exceed the SIL has been calculated and presented in Table 7-1. The only pollutant that required an AOI calculation was 1-hour NO_2 with an AOI of 9.24 km. However, BMOP has conservatively incorporated inventory sources up to 50 km for the full impacts analysis. The regional inventory sources were obtained from BOEM's latest published emission inventory data: the 2017 Gulfwide Emission Inventory. BOEM collects the operational activity data on a tri-annual basis under Gulfwide Offshore Activity Data System (GOADS) program from both platform and non-platform sources in the Gulf of Mexico (GOM). BOEM publishes the emissions generated from these sources for the reporting year, therefore, the GOADS data collected for the Project is based on emissions for the 2017 reporting year.[13] To develop the regional inventory used in the full impacts analyses, only platform emission sources have been included, as non-platform sources are considered mobile (non-stationary) sources such as helicopters, support vessels, etc. The following figure shows the extent of the AOI for 1-hour NO_2 and the larger area covered by the regional inventory sources to ensure sufficient buffer between the receptors that exceed the SIL and the inventory selected to evaluate refined modeling impacts.

[12] www.epa.gov/sites/default/files/2020-09/documents/appw_17.pdf

[13] The inventory has not been updated by BOEM since the 2017 version.

Figure 4-2. 1-Hour NO_2 AOI and Regional Inventory



4.1.4 Significant Monitoring Concentrations

To determine whether pre-construction monitoring should be considered, the maximum impacts attributable to the proposed project have been assessed against Significant Monitoring Concentrations (SMCs). The SMC for the applicable averaging periods for CO, NO_2, and PM_{10} are provided in 40 CFR 52.21(i)(5)(i) as well as Table 4--1 of this report. Consistent with EPA guidance, the proposed ambient background monitoring data for $PM_{2.5}$ has been considered to satisfy preconstruction monitoring requirements for $PM_{2.5}$. Typically, if the significance modeling shows that maximum modeled concentrations from the affected emissions sources do not exceed the SMCs for the modeled pollutants, pre-construction monitoring may be avoided. However, given the existence of representative, state-run monitoring networks for all applicable pollutants in the densely populated and heavily industrialized onshore portions of Louisiana, BMOP is conservatively using the existing monitoring data in lieu of any preconstruction monitoring for demonstrating compliance with the NAAQS for this project. Background monitoring data is further discussed in Section 5.3.

4.1.5 NAAQS Analysis

For criteria pollutants with a significant off-property impact, the PSD analysis requires additional modeling that includes a NAAQS analysis. The NAAQS analysis demonstrates that the proposed project will not cause nor contribute to a violation of NAAQS considering background monitoring data and other nearby sources. Table 7-1 presents the NAAQS results for the pollutants that exceeded the SIL.

For off-site inventory sources, necessary refinements have been incorporated in the NAAQS models based on the publicly available information. The most recent emission inventories (off-property emission sources)

presented in the modeling protocol for all applicable pollutants has been obtained from the BOEM Emissions Inventories database[14].

Typically, the ambient concentration for each applicable pollutant and averaging period is calculated by adding the appropriate modeled concentration from the NAAQS model to the monitored background concentration for the surrounding area. As shown in Table 7-1, the ambient concentration for each applicable NAAQS model is less than the corresponding NAAQS; therefore, the proposed project does not cause nor contribute to violation of the NAAQS and no additional analysis is required.

4.1.6 PSD Increment Analysis

For pollutants, for which a PSD Increment standard is applicable, with a modeled concentration greater than the respective SILs indicated in Table 4-1, PSD regulations require a PSD Increment analysis. The PSD Increment analysis demonstrates that the proposed project will neither cause nor contribute to an exceedance of any PSD Increment standards. There are three PSD Increment zoning classifications as shown below:

- A Class I area for restricted industrial growth (federal protected lands, etc.);
- A Class II area for controlled industrial growth; and
- A Class III area for expanded industrial growth.

The DWP is located 80 miles offshore from the nearest U.S. State (Louisiana); therefore, BMOP is addressing PSD increment standards based on a Class II evaluation. Table 7-1 presents the Class II PSD Increment standards for pollutants that have been addressed for the proposed project. Each PSD Increment pollutant and averaging period combination demonstrated compliance with the corresponding SIL thresholds; therefore, BMOP has demonstrated that the proposed project does not cause nor contribute to a violation of the Class II PSD Increment Standards and no additional analysis is required.

4.1.7 Secondary $PM_{2.5}$ and Ozone Impact Analysis

Due to project emissions of the secondary $PM_{2.5}$ precursors (NO_X and SO_2) and ozone precursors (NO_X and VOC), BMOP will perform an ambient air quality impact analysis for secondary $PM_{2.5}$ and ozone as required in 40 CFR 52.21. Elevated ground-level ozone concentrations are the result of photochemical reactions among various chemical species. These reactions are more likely to occur under certain ambient conditions (e.g., high ground-level temperatures, light winds, and sunny conditions). The chemical species that contribute to ozone formation, referred to as ozone precursors, include NO_X and VOC emissions from both anthropogenic (e.g., mobile and stationary sources) and natural sources (e.g., vegetation). BMOP will perform a Tier 1 assessment to satisfy the requirements of both ambient impact analyses using the latest MERPs guidance from the U.S. EPA issued on April 30, 2019.[15]

[14] https://www.boem.gov/environment/environmental-studies/ocs-emissions-inventories

[15] U.S. Environmental Protection Agency. "Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program." Apr. 30, 2019. https://www.epa.gov/sites/production/files/2020-09/documents/epa-454_r-19-003.pdf.

5. CLASS II AREA AIR DISPERSION MODELING ANALYSES

Section 5.1 describes the potential model software used for the analysis. Section 5.2 describes the meteorological data being used for the project's air quality analysis. Section 5.3 describes the background monitor selection. Section 5.4 describes the topography of the area surrounding the project. Section 5.5 describes the stack height analysis for each emission source that has been modeled. Section 5.6 describes the building wake (downwash) analysis for all the structures situated within the safety zone. Section 5.7 describes the virtual receptor grids used in the model. Section 5.8 describes the emission rates and Section 5.9 describes the default source parameters used in the analysis as a substitute for missing inventory data.

5.1 DISPERSION MODEL SELECTION

The American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) is the U.S. EPA-recommended model for evaluating near-field impacts (*i.e.*, source receptor distances of less than or equal to 50 km). The AERMOD modeling system is composed of three modular components: AERMAP, the terrain preprocessor; AERCOARE, the over-water meteorological preprocessor; and AERMOD, the control module and modeling processor. The most recent U.S. EPA approved version of the AERMOD processor version 22112 has been used. All AERMOD dispersion modeling will be performed using the regulatory default option.

5.2 METEOROLOGICAL DATA

AERMOD is a refined, steady-state, multiple source, Gaussian dispersion model and was promulgated in December 2005 as a preferred model for use by industrial sources for NSR and PSD air quality analysis.[16] However, due to the steady-state assumption of AERMOD, gaussian plume models are generally applicable to distances less than 50 km.

The AERMOD modeling system is composed of three modular components: AERMAP, the terrain preprocessor; AERMET, the meteorological preprocessor; and AERMOD, the dispersion and post-processing module. AERMAP is the terrain pre-processor that is used to import terrain elevations for selected model objects and to generate the receptor hill height scale data that are used by AERMOD to drive advanced terrain processing algorithms. For typical onshore modeling projects, the models utilize AERMET to generate a separate surface file and vertical profile file to pass meteorological observations and turbulence parameters to AERMOD. However, in this particular setting at an offshore and overwater location, use of AERMET/AERSURFACE and the standard meteorological data preparation techniques, are not appropriate.

For the purpose of modeling offshore air dispersion, AERCOARE, the overwater meteorological data processor, has been used as the meteorological data processor for this project. As required by Section 3.2.2 of 40 CFR 51, Appendix W, a request for approval for the use of an alternative model was previously submitted to EPA for approval of the use of AERCOARE for this project, providing justification that the use of AERCOARE to generate overwater meteorological data to use with AERMOD is more appropriate and applicable over EPA's preferred air quality model and techniques. [17] The data selection and substitution are discussed further in the next section.

[16] 40 CFR Part 51, Appendix W, Guideline on Air Quality Models, Appendix A.1 AMS/EPA Regulatory Model (AERMOD).

[17] An alternative modeling request for use of AERCOARE was provided under separate cover to EPA on January 26, 2021. An updated alternative modeling request will be provided to EPA for this project under separate cover.

5.2.1 Data Selection and Proposed Substitution

To find appropriate meteorological data, available buoy data from the Gulf of Mexico was evaluated from the NOAA website[18], with both the most recent five years of data as well as recent historical years being evaluated in order to find an appropriate buoy with sufficient good-quality data. AERCOARE typically requires wind speed, wind direction, air temperature, water temperature, and relative humidity measurements from an offshore buoy in a representative location. Most of the buoys found in this region of the Gulf measure only a subset of the AERCOARE-required parameters. The closest buoy to the project site which measures all of the necessary parameters and had generally good data quality for a recent historical period is the National Buoy Data Center's Station 42035, located 22 nautical miles (25.3 statute miles, or 40.7 kilometers) east of Galveston, Texas, and approximately 88.2 nautical miles (101.5 statute miles, or 163.4 kilometers) northwest of the Project location.

Figure 5-1. Locations of Buoy 42035 and BMOP Project

While intermittent periods of missing data (which are more common at offshore buoys than at typical onshore weather stations due to the harsh conditions and difficulty of maintenance access) cause many of the recent years of data at the station to fall below the 90% quarterly completeness threshold, three recent years (2012, 2013, and 2017) were identified in which each quarter exceeded 90% completeness for all required AERCOARE input variables. Additionally, two years (2015 and 2016) were identified in which all parameters except for dewpoint temperature met the 90% quarterly completeness standard. Of those two years, only Q1 2015 met the 90% completeness standard for dewpoint temperature. However, because Station 42035 was superior both in terms of proximity to the project site and data completeness to all other available buoys in the area, this was judged to be the most representative meteorological data source available and thus was selected for use in the AERCOARE processing.

To address the dewpoint temperature completeness issue found at Station 42035 for 2015 and 2016, data, a search was conducted for a buoy that did have good data quality for those years. Station EINL1, operated by the National Ocean Service, was identified as the nearest station to the project site with good quality dewpoint temperature and air temperature data for those years. For the affected quarters of 2015 and 2016, data gaps in the Station 42035 data were filled with EINL1 data.

[18] https://www.ndbc.noaa.gov/station_page.php?station=42035

In addition to the data filling, computation of relative humidity was performed for all five years. This step was necessary because both of the stations used for the processing do not directly record relative humidity, which is a required parameter for AERCOARE. To calculate relative humidity, water vapor pressure (*e*) was first calculated from dewpoint temperature (T_d) using this formula:

$$e = 6.11 * 10^{\left(\frac{7.5T_d}{237.3+T_d}\right)}$$

and saturation vapor pressure (e_s) was calculated from air temperature (T) using this formula:

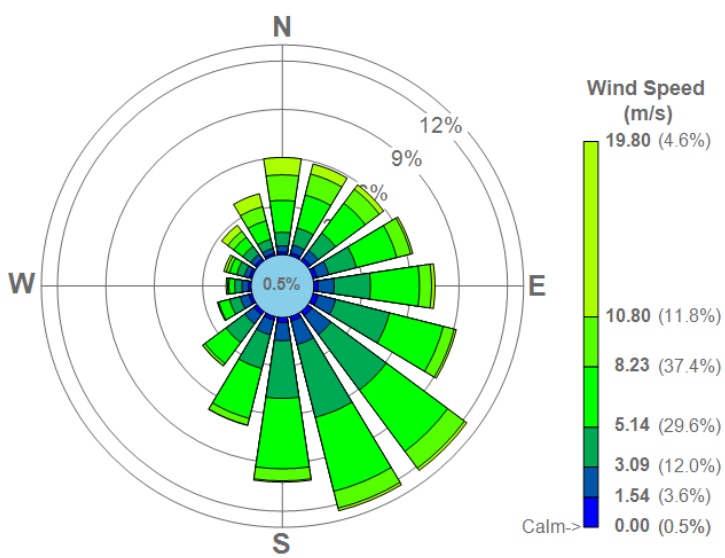
$$e_s = 6.11 * 10^{\left(\frac{7.5T}{237.3+T}\right)}$$

Finally, relative humidity was calculated as:

$$RH = 100\% * \frac{e}{e_s}$$

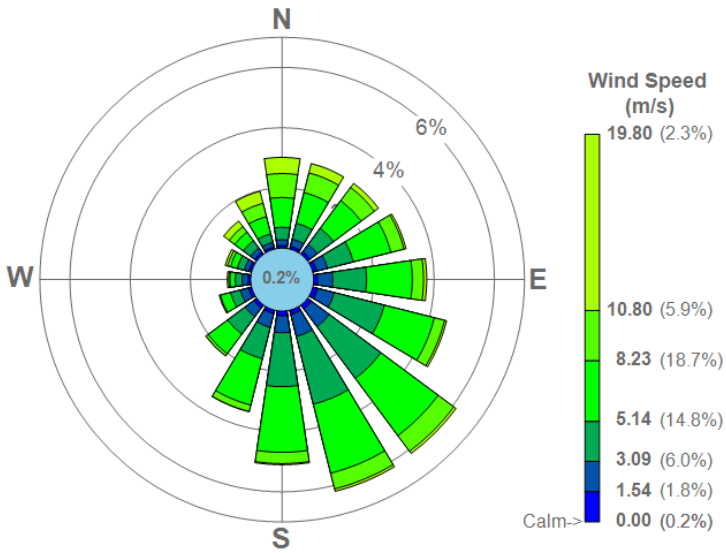
The figures below represent the 5-year average (for 2012, 2013, 2015-2017) wind rose data for both the surface and profile data sets used in the air quality analysis. The surface and profile data sets contain surface characteristics along with wind and temperature observations necessary to determine specific meteorological factors for dispersion calculations. The surface data is based on hourly observations while the profile data is based on twice-daily upper air observations.[19] As shown below, the 5-year average primary wind direction is from the Southeast.

Figure 5-2. Buoy 42035 Surface Data Wind Rose



[19] https://www3.epa.gov/ttn/scram/7thconf/aermod/aermet_userguide.pdf

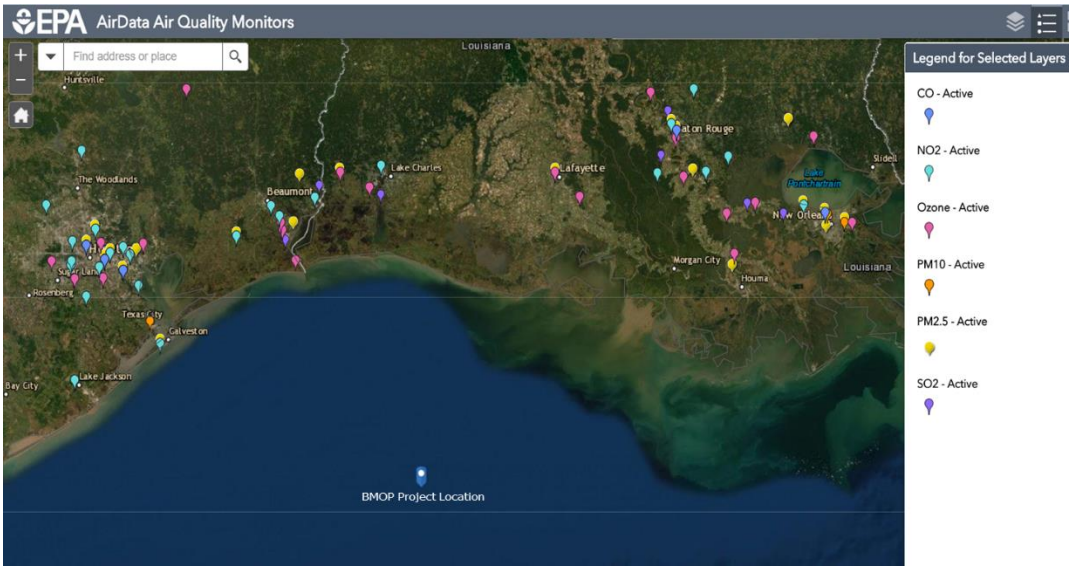
Figure 5-3. Buoy 42035 Profile Data Wind Rose



5.3 BACKGROUND MONITOR SELECTION

Representative ambient background concentrations are necessary for a complete NAAQS analysis. The ambient monitoring data will reflect the most recent and complete years of data (2019-2021, where available). BMOP has considered nearby onshore background monitors and proposed representative monitor data to conservatively allocate ambient pollutant concentrations for the project.

Figure 5-4. Monitors in the Vicinity of the Project



Due to the absence of offshore ambient concentration monitors, a conservative, representative onshore monitor location was selected that best represents the proposed project location. The "representativeness"

of the monitor locations is determined based on several factors; such as distance from the project location, terrain characteristics (e.g., roughness, remote vs industrialized location etc.), as well as the completeness of the available data for required averaging periods. BMOP has utilized the following monitor locations for the various pollutants.

Table 5-1. Background Monitors

Pollutant	Avg. Period	Rank	Site	2018[e]	2019	2020	2021	Ambient Concentration	NAAQS	Units
CO	8-Hr	2nd High	A	NA	0.9	0.8	0.9	0.9 *Highest 2nd High (2021)*	9	ppm
	1-Hr	2nd High	A	NA	1.4	1.2	1.4	1.4 *Highest 2nd High (2021)*	35	ppm
NO_2	1-Hr	98th Percentile	B	NA	23	20	18	20.3 *3-year Average of 98th Percentile*	100	ppb
	Annual	Mean	B	NA	2.75	2.66	3.12	3.12 *Highest Annual Mean (2021)*	53	ppb
$PM_{2.5}$	Annual	Mean	C	7.9	6.8	7.5	NA	7.4 *3-year Average of Annual Mean*	12.0	$\mu g/m^3$
	24-Hr	98th Percentile	C	25	14	22	NA	20.3 *3-year Average of 98th Percentile*	35	$\mu g/m^3$
PM_{10}	24-Hr	2nd High	D	NA	52[a]	90[b]	56[c]	90 *Highest 2nd High (2020)*	150	$\mu g/m^3$
Ozone	8-Hr	4th High	E	NA	0.064	0.064	0.063	0.064[20] *3-year Average of Highest 4th High*	0.070	ppm
SO_2	1-Hr	99th Percentile	E	NA	26	21	25	24 *3-year Average of 99th Percentile*	75	ppb
	3-Hr	2nd High	E	NA	0.03[d]	0.04[d]	0.02[d]	0.04 *Highest 2nd High (2020)*	0.5	ppm
	24-Hr	2nd High	E	NA	0.007	0.006	0.004	0.007 *Highest 2nd High (2019)*	0.14	ppm
	Annual	Mean	E	0.0005	0.001	0.0006	NA	0.001 *Highest Annual Mean (2019)*	0.03	ppm

Notes:
[a] 331 valid days of data of the 365 required days.
[b] 339 valid days of data of the 365 required days.
[c] 354 valid days of data of the 365 required days.
[d] Because 3-hour data is not available, the 2nd highest maximum 1-hour value is utilized.
[e] 2018 data included for pollutants with an incomplete dataset for 2021.

Monitor Station Key:
A: 22-033-0009: 1061-A Leesville Ave, Baton Rouge, LA, ~285 km from DWP.
B. 22-047-0009: 65180 Belleview Road, Iberville, LA, ~ 256 km from DWP.
C: 22-019-0009: 2210-B Bellow Road, Vinton, LA, ~207 km from DWP.
D: 22-055-0007: 700 Cajundome, Lafayette, LA, ~219 km from DWP.
E: 22-019-0011: 8220 Big Lake Rd, Lake Charles, LA, ~186 km from DWP.

[20] Note that this table represents the onshore background monitor data. Offshore background monitor data for the MERPs analysis is discussed in Section 6.

5.4 TERRAIN ELEVATIONS

Typically, the modeling analysis accounts for terrain elevation for each modeled structure, source, and receptor using National Elevation Datasets (NED) data. However, as the proposed project is over water, the default elevation of 0 feet over mean sea level (MSL) has been utilized for each structure, source, and receptor in the model.

5.5 GEP STACK HEIGHT

A GEP stack height evaluation determines if avoidance of building wake effects allows a point source to be modeled at a height greater than 65 meters.

The GEP formula stack height is the greater of 65 meters or (Hb + 1.5L),

Where:

- Hb is the building height, and
- L is the lesser of the building's height or maximum projected width.

These procedures follow the U.S. EPA Guidelines for Determination of GEP Stack Height.[21] This equation only applies to stacks located within 5L of a surrounding structure. In the absence of influencing structures for a specific source, a default GEP height of 65 meters is used. Based on the current design, none of the proposed emissions sources have stacks exceeding their respective GEP height.

5.6 BUILDING WAKE (DOWNWASH) EFFECTS

The emissions sources at the DWP have been evaluated in terms of the equipment proximity to nearby structures. The purpose of this evaluation is to determine if stack discharges may become caught in the turbulent wakes generated by these structures. AERMOD incorporates the Plume Rise Model Enhancements (PRIME) algorithms for estimating enhanced plume growth and restricted plume rise for plumes affected by building wakes.[22]

Direction-specific structure dimensions and the dominant downwash structure parameters used as inputs to AERMOD will be determined using the *BREEZE*® Building Profile Input Program – PRIME Model (BPIPPRM) software, developed by Trinity Consultants, Inc. The BREEZE® software incorporates the algorithms of the U.S. EPA's sanctioned BPIP PRIME (BPIPPRM), version 04274.[23]

The output from the BPIPPRM downwash analysis lists the names and dimensions of the structures generating wake effects and the locations and heights of the affected emissions sources (i.e., stacks). In addition, the output contains a summary of the dominant structure for each emissions source (considering all wind directions) and the actual structure height and projected widths for all wind directions. To account for any impacts on dispersion from the platform structures, BMOP has conservatively included the platforms as a 100% solid structure down to sea level. This information has been incorporated into the AERMOD data input files.

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[21] U.S. EPA's *Technical Support Document for the Stack Height Regulations (Revised)* (1985).

[22] L.L. Schulman, D.G. Strimaitis, and J.S. Scire, Development and Evaluation of the Prime Plume Rise and Building Downwash Model, *AWMA*, 50:378-390, 2000.

[23] U.S. Environmental Protection Agency, *User's Guide to the Building Profile Input Program*, Research Triangle Park, NC, EPA-454/R-93-038.

5.7 PSD/TAPs MODELING RECEPTOR GRID

For the PSD modeling analysis, BMOP is using a Cartesian receptor grid to predict "ground"-level concentrations outside of the safety zone. Receptor spacing varies according to distance from the DWP. Although there is no physical facility boundary, BMOP has requested a safety zone around the DWP to facilitate safe operations at the platform complex as well as vessel traffic near the loading buoys. BMOP has placed receptors at 50-meter intervals along the safety zone. From the safety zone to 2,000 meters (or 2 kilometers), BMOP has placed receptors every 100 meters. From 2 kilometers to 5 kilometers from the property boundary, BMOP has placed receptors every 500 meters. From 5 kilometers to 20 kilometers from the property boundary, BMOP has placed receptors every 1,000 meters. In addition, from 20 kilometers to 50 kilometers from the property boundary, BMOP has placed receptors every 5,000 meters.

The maximum concentration for each modeled pollutant and averaging period occurs at a receptor spaced at 100 meters or less, except for the 1-hour NO_2 NAAQS model where the highest NAAQS result is just outside of the 100-m grid; therefore, an additional hot-spot analysis for the maximum concentrations of 1-hour NO_2 NAAQS model has been included in this analysis, as shown in the following figures.

Figure 5-5. PSD/TAPs Receptor Grid

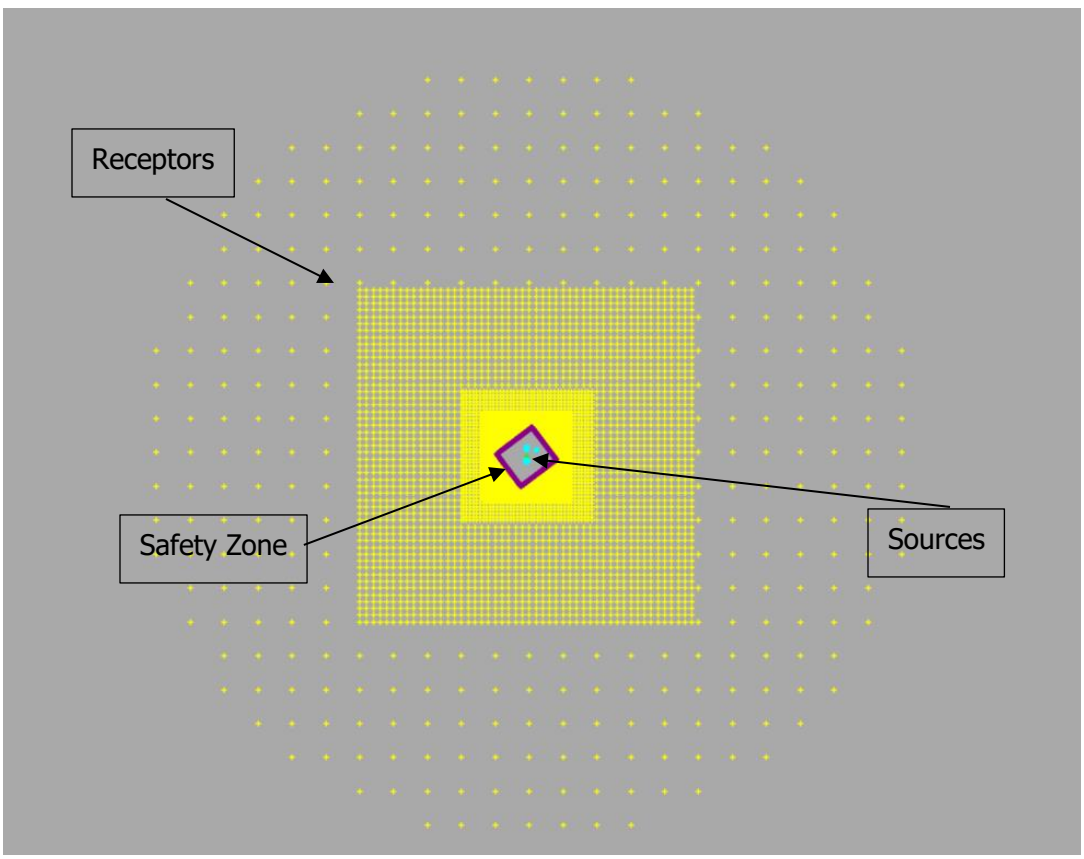
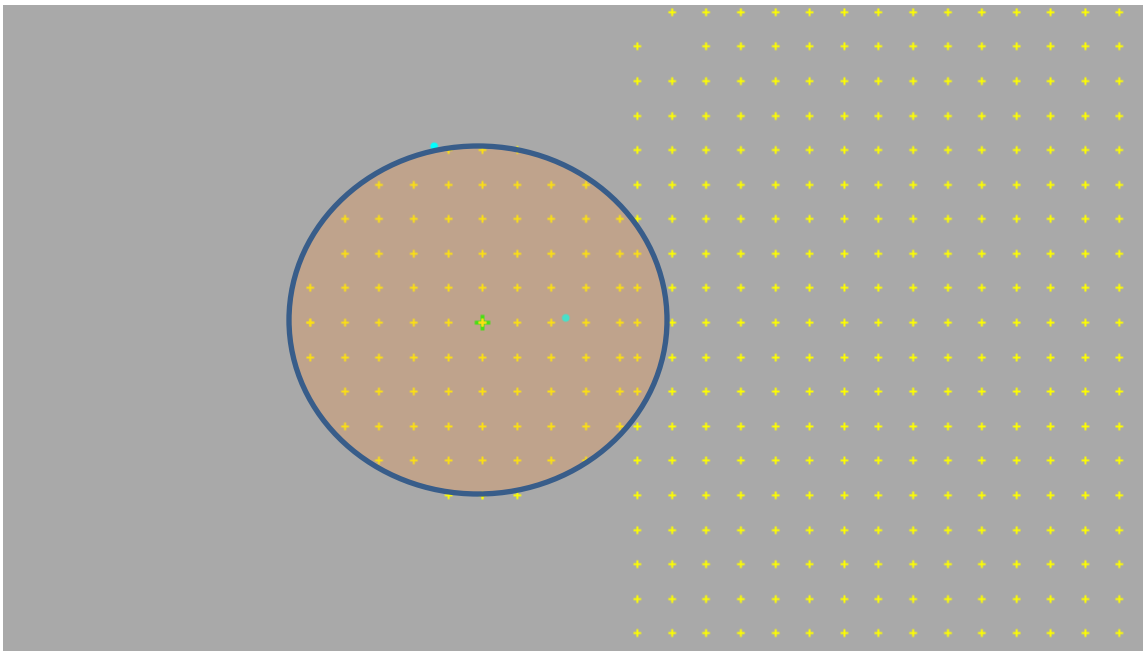


Figure 5-6. Hot-Spot 1-Hour NO_2 Grid



5.8 EMISSION RATES

For the PSD modeling analysis, the modeled emission rates have been based on the project emissions from stationary sources. For pollutants where NAAQS modeling is deemed necessary[24], additional stationary sources from the regional inventory have been incorporated into the PSD analysis. As mentioned in Table 4-1, PSD modeling addresses the following pollutants:

- NO_x
- CO
- PM_{10}
- $PM_{2.5}$

For the toxics modeling analysis, the modeled emission rates have been based on the non-exempt project emissions from stationary sources, similar to the PSD analysis. The toxics modeling also includes the emissions sources that have potential emissions of VOC/toxics only , such as storage tanks, piping component fugitive emissions, and uncaptured emissions from crude loading operations. BMOP has modeled the VOC maximum hourly emissions and utilized crude oil speciation based on the maximum vapor concentrations of TAPs from historic testing at other terminals.

Per 40 CFR 52.21(b)(5) and Louisiana Administrative Code (LAC) 33:III.509.B, a stationary source is defined under PSD regulations as any building, structure, facility, or installation which emits or may emit a regulated New Source Review (NSR) pollutant. Based on this definition, BMOP does not consider the marine engines used to power support vessels and crude vessels calling on the proposed DWP to be part of the stationary source. Therefore, the PSD and Toxics modeling analyses do not include marine sources, as shown in the following table.

[24] Ozone impacts were evaluated in Section 6.

Table 5-2. Modeled Sources

Source	Modeled Location	Included in PSD Models?	Included in Toxics Models?
Vapor Combustion Units	Platform A	Yes	Note
Internal Combustion Engines	Platform B	Yes	Note
Flares	Vent boom extending from Platform B	Yes	Note
Emergency Internal Combustion Engines	Platform B Platform C	Yes	Note
Support Vessels	Near the Platform Complex	No	No
Supply Vessels	Near the Platform Complex	No	No
Tugboats with Main and Auxiliary Engines	Near Crude Oil Carrier	No	No
Crude Oil Carrier Primary and Auxiliary Engines	Buoy	No	No
Helicopter Emissions	Platform C	No	No
Piping Component Fugitive Emissions	509 Platform Complex	No	Yes
Crude Oil Carrier Uncaptured Loading Emissions	Buoy	No	Yes
Storage Tank Emissions	509 Platform Complex	No	Yes

Note: TAP emissions from combustion of Group 1 virgin fossil fuels (natural gas, diesel, gasoline, and distillate fuel oil) are exempt from the toxics modeling provisions under LAC 33.III.5105.B.3.a.

The following tables show the modeled hourly and annual emission rates for stationary sources included in the PSD and toxics modeling evaluations.

Table 5-3. Stationary Point Sources

ID	Emissions Unit	Modeled Profile[a]	NO_X		CO	VOC	PM_{10}		$PM_{2.5}$	
			lb/hr	tpy	lb/hr	lb/hr	lb/hr	tpy	lb/hr	tpy
AVT	Aviation Fuel Storage	Continuous	-	-	-	1.17E-04	-	-	-	-
NGGEN1	Natural Gas Generator #1[b]	Continuous	2.57	11.24	1.18	1.44	0.18	0.80	0.18	0.80
DGEN	Emergency Diesel Generator	*Intermittent*	0.03	0.15	2.59	2.96	0.01	0.01	0.01	0.01
BCRANE1	Platform B Crane #1	Continuous	0.47	1.03	2.73	0.22	0.05	0.11	0.05	0.11
BCRANE2	Platform B Crane #2	Continuous	0.47	1.03	2.73	0.22	0.05	0.11	0.05	0.11
BFWP	Platform B Firewater Pump	*Intermittent*	0.05	0.21	3.73	4.30	0.01	0.01	0.01	0.01
DT1	Platform B Crane Tank #1	Continuous	-	-	-	4.42E-04	-	-	-	-
DT2	Platform B Crane Tank #2	Continuous	-	-	-	4.42E-04	-	-	-	-
DT	Primary Diesel Storage Tank	Continuous	-	-	-	1.94E-03	-	-	-	-
ST	Surge Tank	Continuous	-	-	-	0.85	-	-	-	-
CFWP	Platform C Firewater Pump	*Intermittent*	0.05	0.21	3.73	4.30	0.01	0.01	0.01	0.01
VCU1	VCU Stack 1	Continuous	32.71	143.29	60.08	82.32	1.14	4.99	1.14	4.99
VCU2	VCU Stack 2	Continuous	32.71	143.29	60.08	82.32	1.14	4.99	1.14	4.99
VCU3	VCU Stack 3	Continuous	32.71	143.29	60.08	82.32	1.14	4.99	1.14	4.99
UNLD1	Uncontrolled Loading at Buoy #1[c]	Continuous	-	-	-	4989.04	-	-	-	-
HP Flare	High Pressure Flare tip at tripod	*Intermittent*	0.24	1.03	2.06	0.01	-	-	-	-
LP Flare	Low Pressure Flare tip at tripod	*Intermittent*	0.92	4.03	58.51	384.78	-	-	-	-

Notes:

a. Sources with intermittent operation have annualized hourly emissions modeled for the NO_2 1-hour averaging period.
b. Although two natural gas generators are proposed in the permit application, only one of the two generators is expected to operate in a given hour. Therefore, the modeling analysis only includes a single natural gas generator.
c. Uncontrolled/uncaptured loading will occur only at one of the two buoys in a given hour. Therefore, the toxics model includes the maximum lb/hr emissions for loading from only one of the two buoys.

Table 5-4. Stationary Volume Sources

ID	Emissions Unit	VOC (lb/hr)
FUG41	Fuel Gas Scrubber	0.068
FUG5/6	Condensate Pump No. 1 and 2	0.049, each
FUG39/40	Pig Launcher No. 1 and 2 (Gas Export)	0.132, each
FUG10	Pig Receiver (Oil Import)	0.104
FUG42	Crude Oil Mainline	0.104
FUG11	Oil Meter Skid	0.571
FUG12	Meter Prover Skid	0.083
FUG13/14	Pig Launcher No. 1 and 2 (Export to VLCC)	0.208, each
FUG15/16	CALM Buoy #1 and 2	0.203, each
FUG17	Surge Relief Valve Skid	0.195
FUG18	Surge Tank	0.209
FUG19/20	Surge Tank Pump No. 1 and 2	0.043, each
FUG21/22	Sump System No. 1 and 2	0.249, each
FUG23/24	Firewater Pump No. 1 and 2	0.051, each
FUG25/26	Air Compressor No. 1 and 2	0.043, each
FUG27	Crane Diesel Tank No. 1	0.043
FUG29/30	Platform Crane No. 1 and 2	0.043, each
FUG31	Diesel Transfer Skid	0.267
FUG43	LQ Crane	0.267
FUG44/45	Diesel Transfer Pump No. 1 and 2	0.267, each
FUG32/33	Gas Generator No. 1 and 2	0.015, each
FUG34	Emergency Diesel Generator	0.051
FUG35	Knockout System	0.083
FUG36	Fuel Gas Skid	0.229
FUG37/38	Aviation Refueling System No. 1 and 2	0.111, each
FUG46	Three (3) VCU Systems	0.291
FUG47	High Pressure Flare Scrubber and Pump	0.007
FUG48	Low Pressure Flare	0.007

5.9 SOURCE PARAMETERS

The source specific stack parameters used for the air dispersion modeling analysis are based on project design specifications. The following tables provide the modeled stack parameters utilized for the modeling analysis.

Table 5-5. Modeled Point Source Stack Parameters

Source ID	Stack Height (ft)	Stack Temp. (F)	Stack Velocity (ft/s)	Stack Diameter (ft)
NGGEN1	114.4	924	125.98	0.67
DGEN	104.4	756.68	103	0.67
BCRANE1	154.67	980.33	97.27	0.33
BCRANE2	154.67	980.33	97.27	0.33
BFWP	56.16	980.33	133.1	0.33
CFWP	56.06	980.33	133.1	0.33
VCU1	136	600	65.62	12.63
VCU2	136	600	65.62	12.63
VCU3	136	600	65.62	12.63
HPF	186	1832	65.62	21.22
LPF	186	1832	65.62	8.39
ST	105.06	150	3.28	0.5
DT	105.06	150	3.28	0.5
DT1	105.06	150	3.28	0.5
DT2	105.06	150	3.28	0.5
AVT	105.06	150	3.28	0.5
UNLD1	50	305	30	40

Table 5-6. Modeled Volume Source Stack Parameters

Source ID	Release Height (ft)	Init. Lat. Dim. (ft)	Init. Vert. Dim. (ft)
FUG5	56.16	9.8	8
FUG6	56.16	9.8	8
FUG10	64.16	38.88	8
FUG11	107.4	37.08	15
FUG12	102.4	12.65	10
FUG13	130.44	19.44	8
FUG14	130.44	19.44	8
FUG15	6.5	20	20
FUG16	6.5	20	20
FUG17	134.1	17.66	11.67
FUG18	110.4	26.32	18
FUG19	99.9	2.65	7.5
FUG20	99.9	2.65	7.5
FUG21	58.16	11.4	10
FUG22	58.06	15	8
FUG23	56.16	12.96	14
FUG24	56.06	12.96	14
FUG25	92.4	9.01	16.25
FUG26	92.4	9.01	16.25
FUG29	154.67	20	30
FUG30	154.67	20	30
FUG31	65.16	7.48	9

Source ID	Release Height (ft)	Init. Lat. Dim. (ft)	Init. Vert. Dim. (ft)
FUG32	114.4	19.6	12
FUG33	114.4	19.6	12
FUG34	104.4	19.6	12
FUG35	73.16	12.37	9
FUG36	56.16	12.25	11
FUG37	56.16	13.96	13
FUG27	110.4	26.32	18
FUG38	56.15623	13.96	13
FUG39	122.44	19.44	8
FUG40	122.44	19.44	8
FUG41	56.1	9.8	8
FUG42	56.16	9.8	8
FUG43	56.16	9.8	8
FUG44	56.16	12.96	14
FUG45	56.16	12.96	14
FUG46	56.16	12.96	14
FUG47	56.16	12.96	14
FUG48	56.16	12.96	14

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6. OZONE AND $PM_{2.5}$ TIER I MERPS ANALYSIS

Secondary pollutants are air pollutants formed through chemical reactions in the atmosphere. Secondary $PM_{2.5}$ and ozone share common sources of emissions and are formed in the atmosphere from chemical reactions with similar precursors. Surface-level ozone concentrations are the result of photochemical reactions among various chemical species. The chemical species that contribute to ozone formation, referred to as ozone precursors, include NO_X and VOC emissions from both anthropogenic (e.g., mobile and stationary sources) and natural sources (e.g., vegetation). Regarding $PM_{2.5}$, total mass is often categorized into primary (i.e., emitted directly as $PM_{2.5}$ from sources) and secondary (i.e., $PM_{2.5}$ formed in the atmosphere by precursor emissions from sources). $PM_{2.5}$ is dominated by a variety of chemical components including sulfate, nitrate, ammonium, organic carbon, and sea-spray constituents.[25] $PM_{2.5}$ sulfate and nitrate are predominantly the result of chemical reactions of the oxidized products of SO_2 and NO_X precursor emissions.[26]

The methods presented in this section are based on each precursor pollutant from the Project that is greater than or equal to its respective SER triggering a secondary impacts analysis for that individual pollutant following Table III-1 (*EPA Recommended Approaches for Assessing O_3 Impacts by Assessment Case*) and Table III-2 (*EPA Recommended Approaches for Assessing Primary and Secondary $PM_{2.5}$ Impacts by Assessment Case*) of the EPA *Guidance for Ozone and Fine Particulate Matter Permit Modeling (July 2022)*.[27] If a precursor pollutant is less than its respective SER, a secondary impacts analysis for that individual pollutant will not be required. As provided in Volume I of the PSD air permit application, potential Project emissions of $PM_{2.5}$, NO_X, and SO_2, and VOC from the Project exceed the corresponding major source threshold and SER, and therefore, secondary impacts from $PM_{2.5}$ and ozone are evaluated as part of the PSD application.

Because the Project location is >130 km from the nearest coastline, BMOP has estimated both (1) offshore secondary impacts and (2) onshore secondary impacts using the methods described below for ozone and $PM_{2.5}$. This section of the report describes the methods BMOP used to estimate the impact of the Project's proposed precursor emissions of ozone and $PM_{2.5}$ (i.e., NO_X and VOC impact on ozone, and NO_x and SO_2 impact on $PM_{2.5}$).

6.1 MERPs as a Tier 1 Demonstration Tool

The latest revisions to the *Guideline on Air Quality Models* (hereafter referred to as *Guideline*), which was published in the Federal Register (FR) on January 17, 2017[28] and fully promulgated May 22, 2017,

[25] U.S. EPA, *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program*, EPA-454/R-19-003 (April 30, 2019). Office of Air Quality Planning and Standards, Research Triangle Park, NC. Pg. 13. Refer to: https://www3.epa.gov/ttn/scram/guidance/guide/EPA-454_R-19-003.pdf. (hereafter referred to as *MERPs Guidance*)

[26] Seinfeld, J.H., Pandis, S.N., 2012. *Atmospheric Chemistry and Physics: From Air Pollution to Climate Change*. John Wiley & Sons.

[27] U.S. EPA, *Guidance for Ozone and Fine Particulate Matter Permit Modeling* (July 2022). Office of Air Quality Planning and Standards, Research Triangle Park, NC. Refer to: Guidance for $PM_{2.5}$ Permit Modeling (epa.gov).

[28] *Revisions to the Guideline on Air Quality Models: Enhancements to the AERMOD Dispersion Modeling System and Incorporation of Approaches to Address Ozone and Fine Particulate Matter*, FR 82, No. 10 (January 17, 2017). Pgs. 5182-5235.

established a two-tiered demonstration approach for addressing single-source impacts on ozone.[29] Tier 1 demonstrations rely on the use of technically credible relationships between emissions and ambient impacts based on existing modeling studies deemed sufficient for evaluating a source's impacts. One suggested Tier 1 demonstration approach in the *Guideline* is the use of MERPs. The EPA discusses this approach in detail in the *Guidance on the Development of Modeled Emission Rates for Precursors (MERPs) as a Tier 1 Demonstration Tool for Ozone and $PM_{2.5}$ under the PSD Permitting Program* (hereafter referred to as *MERPs Guidance*).[30]

In the *MERPs Guidance*, the EPA presents photochemical modeling of hypothetical single source impacts on downwind ozone in four geographical regional domains with varying source release types (either "high" at 90 meters or "low" at 10 meters) and varying emission rates (either 500, 1,000, or 3,000 tpy). To use the EPA MERPs hypothetical sources in a PSD secondary impacts determination, the EPA recommends following a three-step process as displayed in Figure 4-1 of the *MERPs Guidance.*[31] In Step 1, the permit applicant should identify a representative hypothetical source from the EPA's *MERPs Guidance* modeling. Additionally, the permit applicant should provide a technically credible justification that the source characteristics of the specific project and the physical and chemical environment near that project source are adequately represented by the selected hypothetical source.[32]

6.2 Selection of MERPs U.S. EPA Hypothetical Source

To begin Step 1, BMOP examined the available EPA hypothetical sources in the Gulf Coast region from the *MERPs Guidance*. Figure 6-1 shows the Project location (green circle) and the nearest four hypothetical sources (red stars): Harris, Texas – FIPS 48201; Acadia, Louisiana – FIPS 22001; Orleans, Louisiana – FIPS 22071; and Bay, Florida – FIPS 12005.[33]

6.2.1 Physical Environment

6.2.1.1 Terrain and Urban Landcover

The EPA provides information for each hypothetical source to facilitate qualitative comparison between hypothetical sources and the project source to determine representativeness.[34] The *MERPs Guidance* information includes the terrain within 50 km of each hypothetical source and maximum grid cell percent urban landcover within 50 km of each hypothetical source to inform the permit applicant about nearby orography and whether the hypothetical source is in proximity to population centers. Table 6-1 provides this information for each of the four Gulf Coast hypothetical sources being considered.[35] The maximum nearby terrain across all four hypothetical sources is all relatively low elevation with only slight variation: Bay is the highest (55 m) and Orleans is the lowest (10 m). The Acadia and Bay hypothetical sources have low maximum nearby urban percentages (6.5% and 9.8%, respectively). The Harris and Orleans hypothetical sources have much higher maximum nearby urban percentages (64.7% and 50.4%, respectively) due to

[29] U.S. EPA, *Guideline on Air Quality Models*, 40 CFR Part 51 - Appendix W (Revised, January 17, 2017).

[30] *MERPs Guidance*.

[31] *MERPs Guidance*, pg. 40.

[32] *MERPs Guidance*, pg. 40.

[33] Note, hypothetical sources that are far inland are not considered in this analysis such as Guadalupe, Texas – FIPS 48187.

[34] *MERPs Guidance*, pg. 21.

[35] *MERPs Guidance*, Table A-1, pg. 64.

their proximity to Houston, Texas and New Orleans, Louisiana. The Project location is > 130 km from the nearest coastline in the Gulf of Mexico with no terrain changes and no urban activity. While the Acadia and Bay hypothetical sources do not exactly align with regard to terrain and urban activity, these two hypothetical sources do align better than the Harris and Orleans hypothetical sources especially with regard to fewer changes in land use/land cover that can impact pollutant dispersion. As such, because of the respective urban features, the Harris and Orleans hypothetical sources are not selected as representative. To help determine whether the remaining Acadia or Bay hypothetical source is more representative, BMOP proceeds with the physical and chemical environment comparison.

Figure 6-1. U.S. EPA Hypothetical Sources Considered

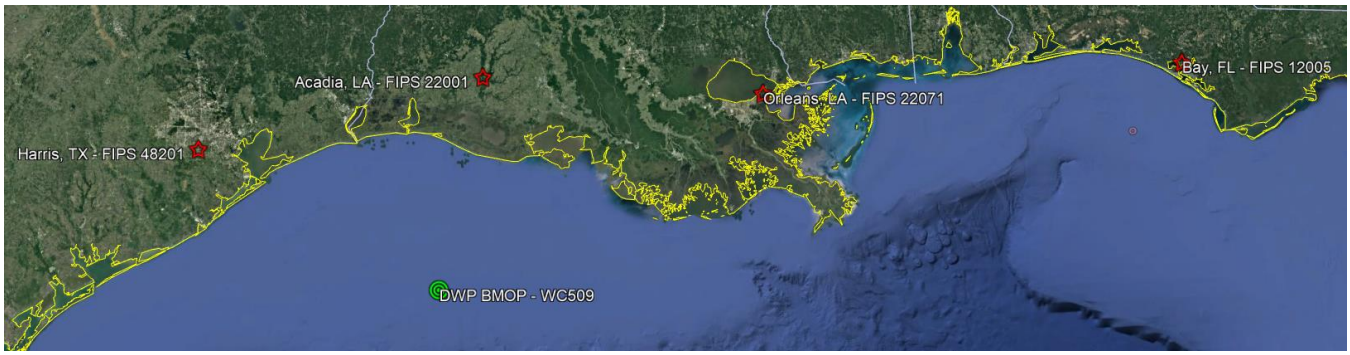


Table 6-1. Information for U.S. EPA Hypothetical Sources Considered

County, State	FIPS #	Max Nearby Terrain[a] (m)	Max Nearby Urban[a] (%)
Harris, Texas	48201	41	64.7
Acadia, Louisiana	22001	16	6.5
Orleans, Louisiana	22071	10	50.4
Bay, Florida	12005	55	9.8

Source: U.S. EPA hypothetical sources (city, state – FIPS #) as provided in the *MERPs Guidance*.

a. "Max Nearby Terrain (m)" and "Max Nearby Urban (%)" are from Table A-1 of the *MERPs Guidance*. Per the U.S. EPA, the "Max Nearby Urban (%)" provides the highest percentage urban landcover in any grid cell near (within 50 km) the hypothetical source.

6.2.1.2 Planetary Boundary Layer Meteorology

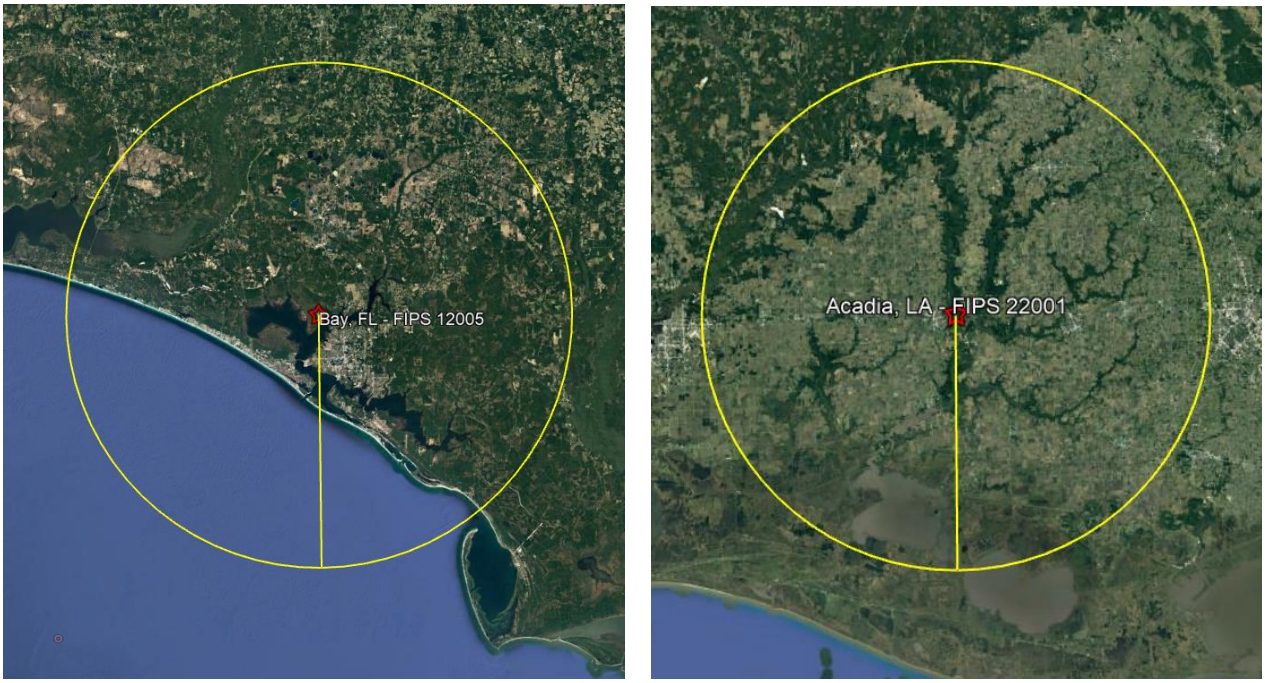
The planetary boundary layer (PBL) is the lowest layer of the atmosphere that is directly influenced by the Earth's surface through forces such as frictional drag, evaporation/transpiration, heat transfer, and pollutant emissions.[36] The depth of the PBL extends from the Earth's surface to a few hundred meters to a few kilometers depending on environmental conditions. This variability in PBL height is important for air quality and atmospheric chemistry because the PBL height determines the volume available for pollutant dispersion. In general, urban areas produce more heat (resulting in buoyant air parcels and convective turbulence), and as a result, the PBL height tends to be higher over cities. Because water has a larger heat capacity and due to the tremendous mixing within the top of the ocean (i.e., the ocean does not respond the same to diurnal

[36] Stull, Ronald B., 1988. *An Introduction to Boundary Layer Meteorology.* Kluwer Academic Publishers.

heating and cooling effects as land does),[37] PBL heights tend to be much lower over the ocean and along the coast.

Figure 6-2 displays both the Bay and Acadia hypothetical sources and the land/ocean within a 50 km radial distance (consistent with the U.S. EPA 50 km distance used for maximum nearby terrain and maximum nearby urban in the *MERPs Guidance*). Based on Figure 6-2, the Acadia hypothetical source has no grid cells within 50 km over the ocean whereas the Bay hypothetical source has ~30% of the grid cell area within 50 km over the ocean. Additionally, the Bay hypothetical source is ~1 km from Panama City Bay and ~14 km from the ocean. As such, the PBL features (e.g., height and diurnal variation) of the Bay hypothetical source location and modeling domain are expected to be more similar to the PBL features of the Project offshore location compared to the Acadia hypothetical source. Based on this comparison, the Bay hypothetical source is considered more representative with regard to PBL features.

Figure 6-2. 50 km Radius Domain for Bay (left) and Acadia (right) Hypothetical Sources



6.2.2 Chemical Environment

6.2.2.1 Regional/Local Emissions

The U.S. EPA National Emissions Inventory (NEI) data is utilized to determine nearby local and regional sources of pollutants and their emissions (e.g., other industry, mobile, biogenic) for the Acadia and Bay hypothetical sources.[38] A similar approach was completed to determine a representative ambient monitor in Table 3 of Appendix C of the U.S. EPA memorandum *Guidance for Ozone and Fine Particulate Matter Permit*

[37] U.S. EPA, *User's Manual AERCOARE Version 1.0*, EPA 910-R-12-008 (October 2012). Office of Environmental Assessment, Region 10, Seattle, WA. Refer to: https://www3.epa.gov/ttn/scram/models/relat/aercoare/AERCOAREv1_0_Users_Manual.pdf.

[38] *MERPs Guidance*, pg. 9.

Modeling.[39] Table 2-2 presents the Acadia County and Bay County 2017 NEI NO_X and VOC emissions.[40], [41] The ratio of VOC to NOx emissions for Bay County (4.39) are comparable to the BMOP Project ratio (5.51) compared to Acadia County (1.89). Based on this comparison, the Bay hypothetical source is considered more representative of the Project geographical area with regard to regional and local emissions.

Table 6-2. 2017 U.S. EPA NEI County Emissions for Acadia and Bay Hypothetical Sources

County, State	County NO_X Emissions (tpy)	County VOC Emissions (tpy)
Acadia, Louisiana	5,044.12	9,553.35
Bay, Florida	6,621.20	29,044.89

Source: U.S. EPA 2017 National Emissions Inventory (NEI) Data. Refer to: https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data#tab-3.

6.2.2.2 Ozone Sensitivity

Ozone formation may be limited by either NO_X or VOC emissions depending on the meteorological conditions and the relative mix of these pollutants.[42] When ozone concentrations are directly related to changes in NO_X emissions, the ozone formation regime is termed "NO_X limited." Alternatively, the ozone formation regime is termed "VOC limited" when ambient ozone concentrations are very sensitive to changes in ambient VOC. In a NO_X-limited regime, ozone decreases with decreasing NO_X and has very little response to changes in VOC. The NO_X-limited formation regime is more common in rural areas of the U.S. where high levels of biogenic VOC exist and relatively few man-made, or anthropogenic, NO_X emissions occur.[43] Ozone decreases with decreasing VOC in a VOC-limited formation regime. Utilizing the complete hypothetical source impact versus distance dataset available on the EPA MERPs View Qlik webpage, BMOP examined the ozone sensitivity to VOC emissions for both the Bay and Acadia hypothetical sources up to distances of 300 km.[44]

Figure 6-3 displays the U.S. EPA Qlik ozone impact versus distance for the Bay and Acadia hypothetical sources for the 1,000 tpy and 90 m stack height scenario in the *MERPs Guidance*. Figure 6-3 shows a maximum impact of ~1 ppb within 50 km for both hypothetical sources. For the Bay hypothetical source, the ozone impact steadily decreases from 40 to 300 km. For the Acadia hypothetical source, the ozone impact begins to steadily decrease from 40 to 80 km. However, the ozone impact begins to increase at 80 km and does not go below the 80 km impact of 0.2 ppb until 240 km. Because of the remote offshore area of the Project, BMOP expects the ozone impact versus distance to resemble the Bay hypothetical source

[39] U.S. EPA, *Guidance for Ozone and Fine Particulate Matter Permit Modeling* (July 2022). Office of Air Quality Planning and Standards, Research Triangle Park, NC. Refer to: Guidance for $PM_{2.5}$ Permit Modeling (epa.gov).

[40] In Louisiana, a "County" is refferred to as a "Parish." For simplicity, Acadia is referred to as "Acadia County" rather than "Acadia Parish" in this analysis.

[41] 2017 NEI data has been used for consistency with the corresponding emissions inventory dataset from BOEM and the metorological dataset utilized for dispersion modeling.

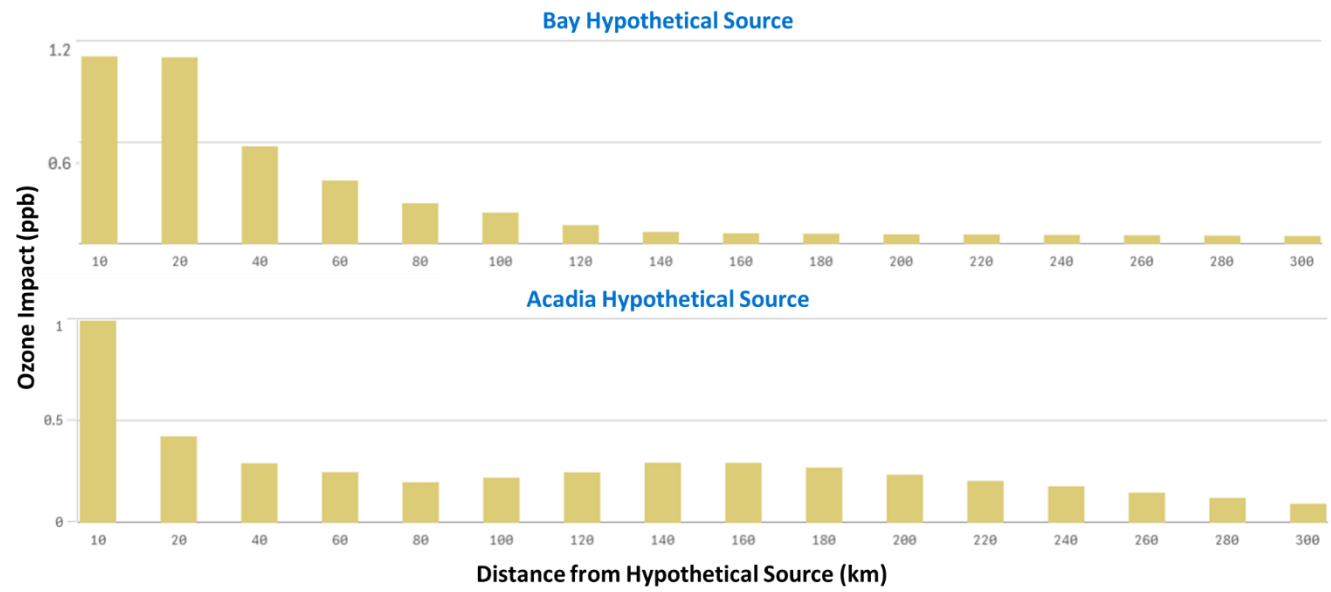
[42] *MERPs Guidance*, pg. 12.

[43] *MERPs Guidance*, pg. 12.

[44] U.S. EPA, *Support Center for Regulatory Atmospheric Modeling – MERPs View Qlik*. Refer to: https://www.epa.gov/scram/merps-view-qlik.

pattern rather than the Acadia pattern. Based on this comparison, the Bay hypothetical source is considered more representative of the Project with regard to ozone sensitivity to VOC emissions at large distances.

Figure 6-3. U.S. EPA Qlik Ozone Impact Versus Distance for the Bay and Acadia Hypothetical Sources (1,000 tpy and 90 m Stack Height Scenario)



Based on the physical and chemical environment comparison above between the Bay and Acadia hypothetical sources, BMOP selects the Bay hypothetical source as more representative of the Project for Ozone impacts. For consistency within this analysis, BMOP will evaluate the $PM_{2.5}$ secondary impacts from the same hypothetical source.

6.3 Offshore Secondary Impacts

6.3.1 Offshore $PM_{2.5}$ Source Impact Analysis

In accordance with the *MERPs Guidance*, BMOP estimated the offshore impact of the Project emissions on $PM_{2.5}$ based on the data provided for the U.S. EPA Bay hypothetical source. To develop the equations, BMOP reviewed the eight U.S. EPA Bay hypothetical source model simulations (i.e., different averaging periods, emissions, and stack height scenarios for NO_x and SO_2) provided in the U.S. EPA MERPs View Qlik interactive website.[45] Based on the proposed emissions of NO_x and SO_2 and associated elevated stack height releases, BMOP selected simulations at 90m and 1,000 tpy for both annual and 24-hour averaging periods as the most representative U.S. EPA modeling simulations to estimate the impact on secondary $PM_{2.5}$.

Utilizing Equation 2 of the *MERPs Guidance* for both NO_X ($PM_{2.5}$ nitrate ion) and SO_2 ($PM_{2.5}$ sulfate ion) air quality impacts and as outlined in example Scenario B on pg. 60 of the *MERPs Guidance*, BMOP calculated the following:

Annual:

$$NOx\ Project\ Impact\text{: } 448.79\ tpy \times \left(\frac{0.010034\ \mu g/m^3\ from\ Bay\ hypothetical\ source}{1000\ tpy\ from\ Bay\ hypothetical\ source}\right) = 0.0045\ \mu g/m^3\ PM_{2.5}$$

[45] U.S. EPA MERPs View Qlik interactive website. Available at: https://www.epa.gov/scram/merps-view-qlik.

$$SO_2\ Project\ Impact: 14.35\ tpy \times \left(\frac{0.032402\ \mu g/m^3\ from\ Louisiana - Acadia\ hypothetical\ source}{1000\ tpy\ from\ Louisiana - Acadia\ hypothetical\ source}\right) = 0.00047\ \mu g/m^3\ PM_{2.5}$$

$$Total\ Project\ Impact: 0.0045\ \mu g/m^3 + 0.00047\ \mu g/m^3 = 0.005\ \mu g/m^3 \textbf{annual}\ secondary\ PM_{2.5}$$

<u>24-hour:</u>

$$NOx\ Project\ Impact: 448.79\ tpy \times \left(\frac{0.141709\ \mu g/m^3\ from\ Bay\ hypothetical\ source}{1000\ tpy\ from\ Bay\ hypothetical\ source}\right) = 0.0636\ \mu g/m^3\ PM_{2.5}$$

$$SO_2\ Project\ Impact: 14.35\ tpy \left(\frac{0.506586\ \mu g/m^3\ from\ Bay\ hypothetical\ source}{1000\ tpy\ from\ Bay\ hypothetical\ source}\right) = 0.0073\ \mu g/m^3\ PM_{2.5}$$

$$Total\ Project\ Impact: 0.0636\ \mu g/m^3 + 0.0073\ \mu g/m^3 = 0.071 \mu g/m^3\ \mathbf{24 - hour}\ secondary\ PM_{2.5}$$

The 24-hour and annual secondary $PM_{2.5}$ values are much lower than the corresponding SIL thresholds. These values have been added to the $PM_{2.5}$ dispersion modeling results in Section 7 to demonstrate that the $PM_{2.5}$ modeled impacts do not violate the NAAQS after accounting for secondary impacts.

6.3.2 Offshore VOC Source Impact Analysis

Similarly, BMOP estimated the offshore impact of the Project emissions on ambient ozone based on the data provided for the U.S. EPA Bay hypothetical source. To do so, BMOP reviewed the Bay hypothetical source model scenarios provided in the *MERPs Guidance* and selected the most representative scenario based on emissions and stack height for NO_X and VOC. Next, BMOP estimated a project specific impact based on the proration of the Project emissions by the ratio of the Bay hypothetical source impact to the Bay hypothetical source emissions.[46]

BMOP considered the precursor impacts together as shown in Equation 1 below. A total project impact calculated in Equation 1 that is less than the applicable Significant Impact Level (SIL) demonstrates the project will not cause or contribute to violation of the applicable NAAQS, and no further analysis is required.[47] If the total project impact in Equation 1 exceeded the corresponding SIL, BMOP performed a cumulative impacts analysis.

<u>8-Hour Ozone Impact using a 1.0 ppb SIL:</u>

$$\boldsymbol{EQ.1}: Total\ Project\ Impact\ (ppb) = \left(\left(\frac{WC509\ Project\ NOx\ (tpy)}{Bay\ Hyp.Source\ NOx\ O_3\ MERP}\right) + \left(\frac{WC509\ Project\ VOC\ (tpy)}{Bay\ Hyp.Source\ VOC\ O_3\ MERP}\right)\right) \times SIL$$

$$\boldsymbol{EQ.1}: Total\ Project\ Impact\ (ppb) = \left(\left(\frac{448.79\ tpy}{263\ tpy^{48}}\right) + \left(\frac{2{,}473\ tpy}{3{,}477\ tpy^{49}}\right)\right) \times 1.0\ ppb$$

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[46] *MERPs Guidance*, pg. 55.

[47] *MERPs Guidance*, pg. 10.

[26] MERP value based on maximum impacts from the Bay hypothetical source with 500 tpy of NO_X emissions and a 90 ft stack.

[27] MERP value based on maximum impacts from the Bay hypothetical source with 3,000 tpy of VOC emissions and a 90 ft stack.

$$\boldsymbol{EQ.1}: Total\ Project\ Impact\ (ppb) = 2.42$$

As shown above, the total impact from the Project is greater than the corresponding SIL for ozone and a cumulative analysis is deemed necessary.

6.3.3 Offshore VOC Cumulative Impact Analysis

As detailed in Section 9 of the *Guideline*, for situations where the proposed project is not able to demonstrate compliance through the source impact analysis, a cumulative impact analysis is required. The cumulative impact is then compared to the applicable NAAQS to determine whether the proposed project could cause or contribute to a NAAQS exceedance. As provided in the *MERPs Guidance*, the cumulative assessment includes the sum of the source impact analysis and the monitored design value as shown below:[50]

$$\boldsymbol{EQ.2}: Projected\ Design\ Value\ with\ Project = Total\ Project\ Impact\ (from\ Eq.1\ above) + Monitored\ Design\ Value$$

BMOP determined the offshore cumulative impacts using Equation 2 for ozone as required. For this offshore cumulative impacts analysis, BMOP utilized a representative offshore ozone value as no ambient ozone monitors exist in the Gulf of Mexico for design value NAAQS purposes. Based on the following references, BMOP determined 40 ppb is a representative, yet conservative, offshore ozone value to use in Equation 2 for the cumulative impacts analysis for ozone:

- Remote marine typical summertime daily maximum ozone concentrations range from 20-40 ppb.[51]
- Ozone measurements taken at a Texas Commission on Environmental Quality (TCEQ) monitoring station in Galveston, Texas, show that levels below 20 ppb are common when air masses originate from the Gulf of Mexico.[52]
- During the Gulf of Mexico and East Coast Carbon Cruise (GOMECC) study aboard the National Oceanic and Atmospheric Administration (NOAA) research vessel Ronald Brown, ozone remained in the 20–30 ppb range in the Gulf of Mexico when southerly winds were encountered.[53]
- Gulf of Mexico background ozone is ~39 ppb based on data from 21 Tunable Optical Profiler for Aerosol and ozone lidar (TOPAZ) flights according to the TCEQ.[54]
- Back-trajectories originating in central Houston, Texas were run for all days with available data from May through October 2000-2007 using the NOAA Air Resource Laboratory (ARL) HYbrid Single-Particle Lagrangian Integrated Trajectory (HYSPLIT) model. Next, a clustering algorithm built into HYPSLIT was used to sequester individual back-trajectories into a relatively small set of classes based on shape and

[50] *MERPs Guidance*, pg. 55.

[51] National Research Council, 1991. *Rethinking the Ozone Problem in Urban and Regional Air Pollution*. Washington, DC: The National Academies Press. Refer to Table 8-1: https://www.nap.edu/read/1889/chapter/10.

[52] Tuite, K., N. Brockway, S.F. Colosimo, K. Grossmann, C. Tsai, J. Flynn, et al. (2018). *Iodine catalyzed ozone destruction at the Texas coast and Gulf of Mexico*. Geophysical Research Letters, 45, 7800–7807. https://doi.org/10.1029/2018GL078267.

[53] Helmig, D., E. K. Lang, L. Bariteau, P. Boylan, C. W. Fairall, L. Ganzeveld, J. E. Hare, J. Hueber, and M. Pallandt (2012). *Atmosphere-ocean ozone fluxes during the TexAQS 2006, STRATUS 2006, GOMECC 2007, GasEx 2008, and AMMA 2008 cruises*. Journal of Geophysical Research, 117, D04305, doi:10.1029/2011JD015955.

[54] Estes, M. (2010), TCEQ. *Background Ozone: Recent Research in the US and Texas*. Presented at the Southeast Texas Photochemical Modeling Technical Committee Meeting. Slide 9 of 24. Refer to: https://www.tceq.texas.gov/assets/public/implementation/air/am/committees/pmt_set/20100407/20100407-estes.pdf.

direction (i.e., clusters). The mean background Houston-Galveston-Brazoria (HGB) ozone was 21 and 25 ppb for the two trajectory clusters originating over the Gulf of Mexico.[55,56]

- Back-trajectories originating in Galveston, Texas were run for all days with available data from May through September 2007-2011 using the NOAA ARL HYSPLIT model. The SAS FASTCLUS procedure was used to define clusters of back trajectories. Clusters 1 and 5 from the Gulf of Mexico were associated with 20-30 ppb ozone.[57]

$$\boldsymbol{EQ.2}: Projected\ Design\ Value\ with\ Project = 2.42\ ppb + 40\ ppb$$
$$\boldsymbol{EQ.2}: Projected\ Design\ Value\ with\ Project = 42.42\ ppb$$

As shown above, the cumulative impacts analysis for ozone results in an air quality level less than the applicable primary NAAQS of 70 ppb, which demonstrates that the Project will not cause or contribute to a violation of the NAAQS.

6.4 Onshore Secondary Impacts

6.4.1 Onshore $PM_{2.5}$ Source Impact Analysis

BMOP estimated the onshore impact of the Project emissions on secondary $PM_{2.5}$ based on Equation 2 above that was utilized to estimate the offshore impact. BMOP utilized the Bay hypothetical source impact versus distance data available on the U.S. EPA MERPs View Qlik webpage rather than utilizing the default maximum impact within 50 km from the *MERPs Guidance.*[58] Specifically, BMOP utilized the U.S. EPA Qlik impact value at the distance from the Project location to the nearest onshore location. BMOP used a distance based gradient for the 120 km range from the database to reflect the distance between the nearest onshore location to the DWP (approximately 130 km). Consistent with the offshore analysis, a calculated total project impact that is less than the applicable SIL demonstrates the project will not cause or contribute to violation of the applicable NAAQS, and no further analysis is required. If the calculated total project impact exceeded the corresponding SIL, BMOP performed a cumulative impacts analysis. The direct impacts of $PM_{2.5}$ are included in the offshore impacts assessment for a 50 km near-field grid. Based on the distance to the shoreline of 130 km, primary $PM_{2.5}$ emissions are not considered in this evaluation.

Annual:

$$NOx\ Project\ Impact: 448.79\ tpy \times \left(\frac{0.002229\ \mu g/m^3\ from\ Bay\ hypothetical\ source}{1000\ tpy\ from\ Bay\ hypothetical\ source}\right) = 0.001\ \mu g/m^3\ PM_{2.5}$$

$$SO_2\ Project\ Impact: 14.35\ tpy \times \left(\frac{0.004804\ \mu g/m^3\ from\ Louisiana - Acadia\ hypothetical\ source}{1000\ tpy\ from\ Louisiana - Acadia\ hypothetical\ source}\right) = 0.0001\ \mu g/m^3\ PM_{2.5}$$

[55] Estes, M. (2009), TCEQ. *Flow Regimes Associated with High Ozone in Houston*. Slide 5 of 45. Refer to: https://www.tceq.texas.gov/assets/public/implementation/air/am/committees/pmt_set/20090917/20090917-estes-flow_regimes.pdf.

[56] Sullivan, D. (2009), The University of Texas at Austin. *Effects of Meteorology on Pollutant Trends*. Final Report to TCEQ. Refer to: https://www.tceq.texas.gov/assets/public/implementation/air/am/contracts/reports/da/5820586245FY0801-20090316-ut-met_effects_on_pollutant_trends.pdf.

[57] Estes, M., J. Smith, and F. Mercado (2014), TCEQ. *Regional Background Ozone in the Eastern Half of Texas*. Presented at the 2014 Community Modeling and Analysis System (CMAS) Conference. Slide 24 of 28. Refer to: https://www.cmascenter.org/conference//2014/slides/mark_estes_regional_sbackground_2014.pptx.

[58] U.S. EPA, *Support Center for Regulatory Atmospheric Modeling – MERPs View Qlik*. Refer to: https://www.epa.gov/scram/merps-view-qlik.

$$Total\ Project\ Impact: 0.001\ \mu g/m^3 + 0.0001\ \mu g/m^3 = \ 0.001\ \mu g/m^3 \textbf{annual}\ secondary\ PM_{2.5}$$

24-hour:

$$NOx\ Project\ Impact: 448.79\ tpy \times \left(\frac{0.058481\ \mu g/m^3\ from\ Bay\ hypothetical\ source}{1000\ tpy\ from\ Bay\ hypothetical\ source}\right) = \ 0.026\ \mu g/m^3\ PM_{2.5}$$

$$SO_2\ Project\ Impact: 14.35\ tpy \left(\frac{0.342576\ \mu g/m^3\ from\ Bay\ hypothetical\ source}{1000\ tpy\ from\ Bay\ hypothetical\ source}\right) = \ 0.0049\ \mu g/m^3\ PM_{2.5}$$

$$Total\ Project\ Impact: 0.026\ \mu g/m^3 + 0.0049\ \mu g/m^3 = \ 0.03 \mu g/m^3\ \mathbf{24-hour}\ secondary\ PM_{2.5}$$

As shown above, the total onshore project impact is below the corresponding SIL. The PSD modeling analysis does not evaluate onshore impacts; however, if these secondary onshore $PM_{2.5}$ impacts were added to the direct modeled maximum SIL based impacts, the proposed project would not exceed the SIL at the onshore location. Therefore, this analysis demonstrates that the Project will not cause or contribute to a violation of the NAAQS. Additionally, since total project impacts are below the $PM_{2.5}$ SIL, a cumulative impacts analysis is not required.

6.4.2 Onshore VOC Source Impact Analysis

BMOP estimated the onshore impact of the Project emissions on ambient ozone based on Equation 1 above that was utilized to estimate the offshore impact. BMOP utilized the Bay hypothetical source impact versus distance data available on the U.S. EPA MERPs View Qlik webpage rather than utilizing the default maximum impact within 50 km from the *MERPs Guidance*.[59] Specifically, BMOP utilized the U.S. EPA Qlik impact value at the distance from the Project location to the nearest onshore location. BMOP used a distance based gradient for the 120 km range from the database to reflect the distance between the nearest onshore location to the DWP (approximately 130 km). Consistent with the offshore analysis, a calculated total project impact that is less than the applicable SIL demonstrates the project will not cause or contribute to violation of the applicable NAAQS, and no further analysis is required. If the calculated total project impact exceeded the corresponding SIL, BMOP performed a cumulative impacts analysis.

<u>8-Hour Ozone Impact using a 1.0 ppb SIL:</u>

$$\boldsymbol{EQ.1}: Total\ Project\ Impact\ (ppb) = \left(\left(\frac{WC509\ Project\ NOx\ (tpy)}{Bay\ Hyp.Source\ NOx\ O_3\ MERP}\right) + \left(\frac{WC509\ Project\ VOC\ (tpy)}{Bay\ Hyp.Source\ VOC\ O_3\ MERP}\right)\right) \times SIL$$

[59] U.S. EPA, *Support Center for Regulatory Atmospheric Modeling – MERPs View Qlik*. Refer to: https://www.epa.gov/scram/merps-view-qlik.

$$\boldsymbol{EQ.1}: Total\ Project\ Impact\ (ppb) = \left(\left(\frac{448.79\ tpy}{1{,}086\ tpy^{60}}\right) + \left(\frac{2{,}473\ tpy}{26{,}620\ tpy^{61}}\right)\right) \times 1.0\ ppb$$

$$\boldsymbol{EQ.1}: Total\ Project\ Impact\ (ppb) = 0.51$$

As shown above, the total project impact is below the corresponding SIL, which demonstrates that the Project will not cause or contribute to a violation of the NAAQS. Additionally, since total project impacts are below the ozone SIL, a cumulative impacts analysis is not required.

[37] Per guidance from EPA, MERP value based on impacts 120 km from the Bay hypothetical source with 1,000 tpy of NO_X emissions and a 90 m stack.

[38] Per guidance from EPA, MERP value based on impacts from the Bay hypothetical source with 1,000 tpy of VOC emissions and a 90 m stack.

7. PSD AND TOXICS MODELING RESULTS

7.1 PSD Dispersion Modeling Results

As mentioned earlier, the results below include each pollutant and averaging period for which the Significance Analysis was performed. For any pollutant and averaging period combination exceeding the SIL thresholds in the Significance Analysis, full impacts modeling was performed.

7.1.1 Significance Analysis

A Significance Analysis was performed for several criteria pollutants (CO, NO_2, PM_{10}, and $PM_{2.5}$) and their respective averaging periods. This section presents the comparison of the Class II PSD SIL to the highest first high (H1H) concentration estimated through modeling. The results of the modeling analysis were compared with the applicable significance levels to determine whether additional modeling was necessary. The significance analysis for 1-hr NO_2 resulted in impacts greater than the significance level. Therefore, a full impacts analysis was completed only for 1-hr NO_2. All other pollutant and averaging period combinations demonstrated compliance with NAAQS and PSD Increment Standards by not exceeding the SIL thresholds of the Significance Analysis.

7.1.1.1 Significance Analysis Impacts

In this analysis, the criteria pollutant potential emissions of the proposed project were modeled for comparison with their respective SILs, which are defined for different averaging periods, as well as the Monitoring *de minimis* concentration (as applicable). Table 7-1 below show the results from this analysis.

Table 7-1. PSD Significance Analysis Results

Pollutant	Averaging Period	Modeled Conc. (µg/m³)	(SIL) (µg/m³)	Modeled Conc. < SIL (Yes/No)	Significant Monitoring Conc. (µg/m³)	Modeled Conc. < Monitoring *de minimis* (Yes/No)	AOI (km)
CO	1-hour	62.58	2,000	Yes	N/A	N/A	--
	8-hour	24.83	500	Yes	575	Yes	--
NO_2	1-hour	22.31	7.5[62]	No	N/A	N/A	9.24
	Annual	0.26	1	Yes	14	Yes	--
PM_{10}	24-Hour	0.24	5	Yes	N/A	N/A	--
	Annual	0.01	1	Yes	10	Yes	--
$PM_{2.5}$[1,2]	24-Hour (NAAQS)	0.15	1.2	Yes	N/A	N/A	--
	24-Hour (Increment)	0.24	1.2	Yes	N/A	N/A	--
	Annual	0.01	0.2[63]	Yes	N/A	N/A	--

[62] Based on U.S. EPA Memorandum from Stephen D. Page to Regional Air Division Directors titled, "Guidance Concerning the Implementation of the 1-hour NO_2 NAAQS for the Prevention of Significant Deterioration Program," June 29, 2010.

[63] Table 1, U.S. Environmental Protection Agency Memorandum. "Guidance on Significant Impact levels for Ozone and Fine Particles in the Prevention of Signifcant Deterioration Permitting Program". Apr. 17, 2018. https://www.epa.gov/sites/production/files/2018-04/documents/sils_guidance_2018.pdf.

[1] PM2.5 24-hour average was modeled as a 5-year meteorological data average as well as for each year separately to allow the SIL results to comply with the form of the NAAQS and PSD Increment standards.
[2] For $PM_{2.5}$ 24-hour and Annual Models, Total Concentration = Primary $PM_{2.5}$ (Modeled Concentration) + Offshore Secondary $PM_{2.5}$ (MERP Analysis)

$PM_{2.5}$ 24-hour (NAAQS) Total Concentration (μg/m^3) = 0.15 + 0.07 = 0.22 μg/m^3
$PM_{2.5}$ 24-hour (Increment) Total Concentration (μg/m^3) = 0.24 + 0.07 = 0.31 μg/m^3
$PM_{2.5}$ Annual Total Concentration (μg/m^3) = 0.01+ 0.005 = 0.015 μg/m^3

As shown in Table 7-1, the Significant Monitoring Concentrations were not exceeded by impacts from the proposed project for 8-hr CO, annual NO_2, 24-hr SO_2, and annual PM_{10} averaging periods. Therefore, preconstruction monitoring is not required. For 1-hr and 8-hr CO, annual NO_2, 24-hr and annual PM_{10}, 24-hr and annual $PM_{2.5}$ averaging periods, the modeled impacts do not exceed the SILs. Therefore, the proposed project will not cause or significantly contribute to an exceedance of their respective NAAQS. Therefore, a full impact analysis is not required for these pollutant/averaging period combinations.

As shown in Table 7-1, the impacts from the 1-hr NO_2 averaging period exceeded the SIL of 7.5 μg/m^3. Therefore, a full impacts analysis was performed for this pollutant and averaging period. No additional evaluation was deemed necessary for PSD Increment Standards as each pollutant and averaging period with a PSD Increment Standard shown in Table 4-1 was under the SIL thresholds. Table 7-1 shows the AOI to be 9.24 km for 1-hr NO_2. BMOP obtained an off-property emissions inventory from BOEM up to 50 km as a conservative measure.

7.1.2 NAAQS ANALYSIS

Based on the output from the significance analysis, the NAAQS analysis was performed for the 1-hr NO_2 averaging period. Table 7-2 summarizes the results of the NAAQS analysis.

Table 7-2. PSD NAAQS Analysis Results

Pollutant	Averaging Period	Rank	Modeled Concentration (μg/m^3)	Background Concentration (μg/m^3)[64]	Total Concentration (μg/m^3)	NAAQS (μg/m^3)	Total Concentration <NAAQS (Yes/No)
NO_2	1-hour	98th Percentile	79.69	38.17	117.85	188	Yes

As shown in Table 7-2, BMOP demonstrates compliance with NAAQS thresholds for all pollutant-averaging period combinations. Therefore, BMOP demonstrates that the proposed project does not cause or contribute to any violations of the NAAQS.

7.2 Toxic Modeling Results

As mentioned previously, BMOP performed Step 1 of the LDEQ modeling methodology for each TAP requiring a modeling analysis in the TAP MER Analysis. Although several pollutants are emitted below the MERs, BMOP has conservatively included speciated model results for each HAP detected in crude oil based on historical HAP speciation data from t crude terminals. For Step 1 of this analysis, BMOP modeled the maximum hourly VOC emissions for the latest year of meteorological data (2017) and speciated the results

[64] Background from Table 5-1 converted from ppb to μg/m^3

to compare directly to the TAPs AAS, as shown below. The modeled concentrations below are based on the highest first high result of each model run.

Table 7-3. Step 1 TAPs Modeled Concentration Results

65Component	VOC Modeled Conc. (µg/m³)		Speciated Modeled Conc. (µg/m³)			AAS (µg/m³)	7.5% AAS (µg/m³)	AOI (km)	Step 2 Analysis Required?
	8-hr	Annual	Spec. wt%[1]	8-hr	Annual				
n-Hexane	7,366.48		4.09	301.29		4,190	314.25	-	No
Benzene		15.87	0.80		0.13	12	0.9	-	No
Toluene	7,366.48		0.36	26.52		8,900	667.5	-	No
Ethylbenzene	7,366.48		0.05	3.68		10,300	772.5	-	No
1,3-dimethylbenzene	7,366.48			3.68		10,300	772.5	-	No
1,4-dimethylbenzene	7,366.48			2.21		10,300	772.5	-	No
1,2-dimethylbenzene (Xylene)	7,366.48		0.29	15.47		10,300	772.5	-	No
i-propylbenzene (Cumene)	7,366.48			0.74		5,860	440	-	No
Biphenyl	7,366.48			0.002		24	2	-	No
Cresols	7,366.48			0.07		238	18	-	No
Naphthalene	7,366.48			0.07		1,190	89	-	No
Phenol	7,366.48			0.07		452	34	-	No

As shown above, speciated model results are under 7.5% of the AAS for each of the HAPs from crude oil with a detectable vapor mass % content and an assigned AAS; therefore, the modeling analysis demonstrates compliance with Step 1 of the Louisiana Toxics Program established in LAC 33:III.Chapter 51. No further toxics modeling assessment is deemed necessary.

[65] Maximum vapor TAP weight percent of total VOC modeled.

8. ADDITIONAL IMPACT ANALYSES

A PSD additional impacts analysis must be conducted to assess the potential impacts of the project on residential, industrial, and commercial growth on local soils and vegetation, and on visibility impairment.

8.1 GROWTH ANALYSIS

The elements of the growth analysis include a projection of the associated industrial, commercial, and residential growth that will occur in the area of impact due to the proposed project, including the potential impact on ambient air due to this growth. Refer to the Environmental Assessment Statement of the Title V Application Forms for additional information.

8.2 SOIL AND VEGETATION ANALYSIS

The U.S. EPA developed the secondary NAAQS in order to protect certain air quality-related values (*i.e.*, soil and vegetation) that were not sufficiently protected by the primary NAAQS. The secondary NAAQS standards (Table 4-1) represent ambient air concentrations below which most types of soil and vegetation are unaffected by criteria pollutants. The impacts from the proposed project will be lower than all primary NAAQS (see Table 7-1 and Table 7-2), which are intended to protect human health and are more stringent than standards intended to protect soil or vegetation. Therefore, the project will not result in harmful effects on either soil or vegetation.

8.3 CLASS I AREA ANALYSIS

Federal guidelines typically require that an air quality dispersion modeling analysis (including a Class I modeling analysis and a visibility analysis) is performed for each Class I area located within 300 km of a facility undergoing an installation or modification that exceeds PSD SER.[66] The nearest Class I area (the Breton Wildlife Refuge) is almost 400 km from the Project location. Potential annual emissions of pollutants that impact air quality related values (e.g., SO_2, NO_X, PM_{10}, and H_2SO_4) are estimated to be approximately 480 tpy (see emissions calculations included in Appendix C of the PSD application). Per the revised FLAG 2010 Report, the project would not be considered to cause or contribute to the visibility impairment of the Class I area if the Q (*sum of emissions of SO_2, NO_X, PM_{10}, and H_2SO_4*)/d (*distance from project to Class I area*) calculation is less than 10.[67] Therefore, per the revised FLAG 2010 Report, the project would not be considered to cause or contribute to the visibility impairment of the Class I area.[68]

Furthermore, as the distance to the Class I areas is almost 400 km, a ring of receptors at 50 km for Class I SIL evaluation was not deemed necessary.

8.4 NEAR-FIELD VISIBILITY ANALYSIS

Near-field visibility analyses are required for any sensitive receptors (state parks, local airports, etc.) that may be located within the proposed project's daily AOI. If deemed necessary, the analyses are generally conducted in the VISCREEN model, which can consist of two levels: Level 1, with very conservative default settings and Level 2, with more typical meteorological conditions. However, based on the magnitude of

[66] Per the Federal Land Managers AQRV Workgroup (FLAG) Phase I Report (Revised FLAG 2010 Report).

[67] Q=480 tpy, D = 400 km; therefore Q/d = 1.2 tpy/km

[68] Per Section 3.2, *Initial Screening Criteria (New)*, of the revised FLAG 2010 Report.

expected operations and emissions, the proposed project is not anticipated to result in plume blight or visibility issues. There are no sensitive receptors in the project AOI. Therefore, no additional visibility analysis is deemed necessary.

APPENDIX A. REGIONAL INVENTORY

Blue Marlin Offshore Port LLC
Air Quality Modeling Report
Appendix A – Regional Inventory

Off-site Sources based on Year 2017 Gulfwide Offshore Activity Data System (GOADS) Emissions Inventory published by Bureau of Ocean Energy Management (BOEM).
https://www.boem.gov/environment/environmental-studies/ocs-emissions-inventory-2017

Table A-1. Inventory Locations and Stack Parameters

Company Name	Area Block	Distance from BMOP Facility (km)	Model ID	Easting (m)	Northing (m)	Stack Height (ft)	Stack Temp (F)	Stack Velocity (ft/s)	Stack Diameter (ft)
Fieldwood Energy, LLC	EC257	25.8	INS1	525243	3150946	80	900	17.56	1.00
			INS2	525243	3150946	60	1100	26.69	0.67
Fieldwood Energy, LLC	EC265	12.0	INS3	511877	3146394	77	900	277.81	0.25
			INS4	511877	3146394	77	900	245.70	0.17
Fieldwood Energy, LLC	EC278	12.1	INS5	511928	3144721	85	900	214.98	0.33
			INS6	511928	3144721	91	1100	75.12	1.50
			INS7	511928	3144721	94	1100	98.23	0.50
			INS8	511928	3144721	94	1100	91.93	0.50
Arena Offshore, LP	EC321	33.3	INS9	520175	3121571	72	900	17.56	1.00
			INS10	520175	3121571	61	900	17.56	1.00
			INS11	520175	3121571	78	900	301.10	0.50
			INS12	520175	3121571	45	900	0.75	2.00

Company Name	Area Block	Distance from BMOP Facility (km)	Model ID	Easting (m)	Northing (m)	Stack Height (ft)	Stack Temp (F)	Stack Velocity (ft/s)	Stack Diameter (ft)
			INS13	520091	3119373	84	900	4.82	1.00
			INS14	520175	3121571	61	1100	51.55	1.17
			INS15	520091	3119373	84	1100	19.93	1.00
			INS16	520175	3121571	40	1000	83.50	2.00
			INS17	520175	3121571	40	1000	83.50	2.00
			INS18	520175	3121571	40	1000	83.50	2.00
			INS19	520175	3121571	40	1000	83.50	2.00
Arena Offshore, LP	EC328	42.7	INS20	530873	3116516	80	500	32.96	1.67
			INS21	530873	3116516	80	500	32.96	1.67
			INS22	530873	3116516	80	500	32.96	1.67
			INS23	530873	3116516	80	500	32.96	1.67
			INS24	530873	3116516	80	500	32.96	1.67
			INS25	530873	3116516	80	500	32.96	1.67
			INS26	530873	3116516	95	150	50.97	0.46
			INS27	530873	3116516	85	150	407.73	0.16
			INS28	529986	3117188	95	150	50.97	0.46
			INS29	529986	3117188	100	800	12.03	0.67

Company Name	Area Block	Distance from BMOP Facility (km)	Model ID	Easting (m)	Northing (m)	Stack Height (ft)	Stack Temp (F)	Stack Velocity (ft/s)	Stack Diameter (ft)
			INS30	530873	3116516	54	250	21.77	1.00
			INS31	530873	3116516	54	250	21.77	1.00
			INS32	530873	3116516	100	900	84.99	1.00
			INS33	530873	3116516	100	900	84.99	1.00
Fieldwood Energy, LLC	EC332	33.4	INS34	513499	3115388	87	400	13.66	1.50
			INS35	513499	3115388	80	900	95.55	0.50
			INS36	513499	3115388	80	900	100.37	0.50
			INS37	513499	3115388	100	900	120.44	0.50
			INS38	513499	3115388	82	1100	28.35	1.50
			INS39	513499	3115388	97	1100	70.54	0.83
Energy XXI GOM, LLC	EC334	32.7	INS40	500901	3116225	98	450	135.17	0.25
			INS41	500901	3116225	90	450	168.96	0.25
			INS42	500901	3116225	90	450	168.96	0.25
			INS43	500901	3116225	96.75	850	212.29	0.83
			INS44	500901	3116225	96.75	850	162.96	0.83
W&T Offshore, Inc.	EC338	39.7	INS45	517329	3110226	84	400	7.29	1.50
			INS46	517329	3110226	84	900	70.26	0.50

Company Name	Area Block	Distance from BMOP Facility (km)	Model ID	Easting (m)	Northing (m)	Stack Height (ft)	Stack Temp (F)	Stack Velocity (ft/s)	Stack Diameter (ft)
			INS47	517329	3110226	76	900	93.94	0.50
			INS48	517329	3110226	81	900	78.77	0.83
			INS49	517329	3110226	70	900	4.39	1.00
			INS50	517329	3110226	70	900	33.62	1.00
			INS51	517329	3110226	81	1100	55.11	0.83
			INS52	517329	3110226	81	1100	36.74	0.83
			INS53	517329	3110226	81	1100	33.89	0.83
W&T Offshore, Inc.	EC349	43.6	INS54	515949	3105412	91	900	96.35	0.50
			INS55	515949	3105412	81	900	31.62	0.33
Fieldwood Energy, LLC	VR261	41.3	INS56	539897	3156382	78	900	160.59	0.25
			INS57	539848	3156415	100	900	10.04	1.00
			INS58	539848	3156415	100	1100	45.03	1.00
			INS59	539848	3156415	100	1100	14.99	1.00
			INS60	539848	3156415	100	1100	14.99	1.00
			INS61	539848	3156415	100	1100	14.99	1.00
W&T Offshore, Inc.	VR279	48.1	INS62	547983	3147094	90	400	20.49	1.00
			INS63	547983	3147094	90	400	20.49	1.00

Company Name	Area Block	Distance from BMOP Facility (km)	Model ID	Easting (m)	Northing (m)	Stack Height (ft)	Stack Temp (F)	Stack Velocity (ft/s)	Stack Diameter (ft)
			INS64	547983	3147094	94	900	23.89	1.00
			INS65	547983	3147094	92	900	42.15	1.00
			INS66	547983	3147094	90	1100	64.36	1.00
			INS67	547983	3147094	90	1100	35.30	1.00
GoMex Energy Offshore, Ltd.	VR282	37.9	INS68	537650	3142772	55	400	67.63	1.00
			INS69	537650	3142772	60	900	10.14	1.00
			INS70	537650	3142772	60	900	10.04	1.00
			INS71	537650	3142772	63	1100	65.06	1.00
			INS72	537650	3142772	63	1100	63.78	1.00
Fieldwood Energy, LLC	WC485	8.6	INS73	492610	3150512	68	900	45.16	0.33
			INS74	492610	3150512	68	900	144.53	0.33
			INS75	492610	3150512	75	1100	55.81	1.00
			INS76	492610	3150512	75	1100	55.81	1.00
			INS77	492610	3150512	70	1100	70.16	0.50
Energy XXI GOM, LLC	WC498	46.1	INS78	453816	3147573	80	350	186.48	0.25
			INS79	453816	3147573	100	350	9.65	1.00
			INS80	453816	3147573	100	350	119.79	0.33

Company Name	Area Block	Distance from BMOP Facility (km)	Model ID	Easting (m)	Northing (m)	Stack Height (ft)	Stack Temp (F)	Stack Velocity (ft/s)	Stack Diameter (ft)
			INS81	453816	3147573	96	350	24.06	0.25
			INS82	453816	3147573	98	350	183.48	0.50
			INS83	453816	3147573	78	1100	125.94	1.00
			INS84	453816	3147573	100	400	16.65	2.00
			INS85	453816	3147573	100	450	29.82	1.00
Fieldwood Energy, LLC	WC507	8.1	INS86	492991	3150013	80	900	112.41	0.25
Stingray Pipeline Company, L.L.C.	WC509	0.9	INS87	499489	3145134	66	900	116.21	0.33
			INS88	499489	3145134	64	900	116.21	0.33
			INS89	499489	3145134	126	664	12.83	1.17
			INS90	499489	3145134	126	664	12.83	1.17
Peregrine Oil and Gas II, LLC	WC565	41.9	INS91	463705	3124952	80	900	54.20	0.50

Table A-2. Inventory Emission Rates

Company Name	Area Block	Distance from BMOP Facility (km)	Model ID	NOx (lb/hr)	$PM_{2.5}$ (lb/hr)	PM_{10} (lb/hr)	CO (lb/hr)
Fieldwood Energy, LLC	EC257	25.8	INS1	4.3525	0.2862	0.3060	0.3060
			INS2	2.5333	0.0007	0.0193	0.0193
Fieldwood Energy, LLC	EC265	12.0	INS3	4.3029	0.2830	0.3025	0.3025
			INS4	1.6920	0.1113	0.1189	0.1189
Fieldwood Energy, LLC	EC278	12.1	INS5	5.9194	0.3893	0.4161	0.4161
			INS6	36.0930	0.0093	0.2749	0.2749
			INS7	5.2437	0.0014	0.0399	0.0399
			INS8	5.2437	0.0014	0.0399	0.0399
Arena Offshore, LP	EC321	33.3	INS9	4.5474	0.2990	0.3197	0.3197
			INS10	5.5836	0.3672	0.3925	0.3925
			INS11	7.4654	0.9243	0.2762	0.2777
			INS12	0.7462	0.0491	0.0525	0.0525
			INS13	1.1938	0.0785	0.0839	0.0839
			INS14	11.8411	0.0031	0.0902	0.0902
			INS15	6.0612	0.0016	0.0462	0.0462
			INS16	2.2990	0.0048	0.0248	0.0248
			INS17	2.2990	0.0048	0.0248	0.0248

Company Name	Area Block	Distance from BMOP Facility (km)	Model ID	NOx (lb/hr)	$PM_{2.5}$ (lb/hr)	PM_{10} (lb/hr)	CO (lb/hr)
			INS18	2.3001	0.0048	0.0249	0.0249
			INS19	2.2720	0.0048	0.0246	0.0246
Arena Offshore, LP	EC328	42.7	INS20	0.3906	0.0023	0.0193	0.0193
			INS21	0.3961	0.0024	0.0196	0.0196
			INS22	0.3961	0.0024	0.0196	0.0196
			INS23	0.3967	0.0024	0.0196	0.0196
			INS24	0.3917	0.0024	0.0193	0.0193
			INS25	0.3961	0.0024	0.0196	0.0196
			INS26	4.8344	0.3179	0.3398	0.3398
			INS27	0.8065	0.0530	0.0567	0.0567
			INS28	4.8344	0.3179	0.3398	0.3398
			INS29	1.3268	0.0873	0.0933	0.0933
			INS30	10.2152	0.0026	0.0778	0.0778
			INS31	10.2140	0.0026	0.0778	0.0778
			INS32	20.0848	0.0052	0.1530	0.1530
			INS33	20.0848	0.0052	0.1530	0.1530
	EC332	33.4	INS34	0.1429	0.0009	0.0071	0.0071

Company Name	Area Block	Distance from BMOP Facility (km)	Model ID	NOx (lb/hr)	$PM_{2.5}$ (lb/hr)	PM_{10} (lb/hr)	CO (lb/hr)
Fieldwood Energy, LLC			INS35	5.9191	0.3892	0.4161	0.4161
			INS36	6.2178	0.4089	0.4371	0.4371
			INS37	7.4613	0.4907	0.5245	0.5245
			INS38	13.6200	0.0035	0.1037	0.1037
			INS39	10.4602	0.0027	0.0797	0.0797
Energy XXI GOM, LLC	EC334	32.7	INS40	4.6095	0.3031	0.3240	0.3240
			INS41	2.9220	0.1921	0.2054	0.2054
			INS42	2.5333	0.1666	0.1781	0.1781
			INS43	1.9886	0.0020	0.0005	0.0005
			INS44	4.0186	0.0040	0.0010	0.0010
W&T Offshore, Inc.	EC338	39.7	INS45	0.0714	0.0004	0.0035	0.0035
			INS46	4.3525	0.2862	0.3060	0.3060
			INS47	5.8194	0.3827	0.4091	0.4091
			INS48	13.5548	0.8914	0.9528	0.9528
			INS49	1.0881	0.0716	0.0765	0.0765
			INS50	8.3319	0.5479	0.5857	0.5857
			INS51	12.0519	0.0031	0.0918	0.0918

Company Name	Area Block	Distance from BMOP Facility (km)	Model ID	NOx (lb/hr)	$PM_{2.5}$ (lb/hr)	PM_{10} (lb/hr)	CO (lb/hr)
			INS52	10.9350	0.0028	0.0833	0.0833
			INS53	9.7580	0.0025	0.0743	0.0743
W&T Offshore, Inc.	EC349	43.6	INS54	5.9692	0.3925	0.4196	0.4196
			INS55	0.8706	0.0572	0.0612	0.0612
Fieldwood Energy, LLC	VR261	41.3	INS56	0.6651	0.0437	0.0468	0.0468
			INS57	2.4869	0.1635	0.1748	0.1748
			INS58	9.6157	0.0025	0.0732	0.0732
			INS59	3.2007	0.0008	0.0244	0.0244
			INS60	3.2007	0.0008	0.0244	0.0244
			INS61	3.2011	0.0008	0.0244	0.0244
W&T Offshore, Inc.	VR279	48.1	INS62	0.0919	0.0006	0.0045	0.0045
			INS63	0.0913	0.0005	0.0045	0.0045
			INS64	5.9194	0.3893	0.4161	0.4161
			INS65	10.4482	0.6871	0.7345	0.7345
			INS66	13.1427	0.0034	0.1001	0.1001
			INS67	7.1300	0.0018	0.0543	0.0543
	VR282	37.9	INS68	0.3181	0.0019	0.0157	0.0157

Company Name	Area Block	Distance from BMOP Facility (km)	Model ID	NOx (lb/hr)	$PM_{2.5}$ (lb/hr)	PM_{10} (lb/hr)	CO (lb/hr)
GoMex Energy Offshore, Ltd.			INS69	2.4872	0.1636	0.1748	0.1748
			INS70	2.4871	0.1636	0.1748	0.1748
			INS71	13.8924	0.0036	0.1058	0.1058
			INS72	13.6200	0.0035	0.1037	0.1037
Fieldwood Energy, LLC	WC485	8.6	INS73	1.2436	0.0818	0.0874	0.0874
			INS74	3.9794	0.2617	0.2797	0.2797
			INS75	11.9175	0.0031	0.0908	0.0908
			INS76	11.9175	0.0031	0.0908	0.0908
			INS77	3.7455	0.0010	0.0285	0.0285
Energy XXI GOM, LLC	WC498	46.1	INS78	3.0138	0.1982	0.2119	0.2119
			INS79	0.0408	0.0002	0.0020	0.0020
			INS80	2.1141	0.1390	0.1486	0.1486
			INS81	1.6142	0.1062	0.1135	0.1135
			INS82	1.4810	0.1870	0.0259	0.0264
			INS83	16.3034	0.0042	0.1242	0.1242
			INS84	0.2651	0.0016	0.0131	0.0131
			INS85	16.1891	0.0042	0.1233	0.1233

Company Name	Area Block	Distance from BMOP Facility (km)	Model ID	NOx (lb/hr)	$PM_{2.5}$ (lb/hr)	PM_{10} (lb/hr)	CO (lb/hr)
Fieldwood Energy, LLC	WC507	8.1	INS86	1.7404	0.1144	0.1223	0.1223
Stingray Pipeline Company, L.L.C.	WC509	0.9	INS87	2.4172	0.1590	0.1699	0.1699
			INS88	3.2229	0.2119	0.2266	0.2266
			INS89	7.0388	0.0018	0.0536	0.0536
			INS90	7.1007	0.0018	0.0541	0.0541
Peregrine Oil and Gas II, LLC	WC565	41.9	INS91	3.3592	0.2209	0.2361	0.2361

APPENDIX B. PSD DISPERSION CONTOURS

Figure B-1 CO 1-hr Averaging Period (SIL)

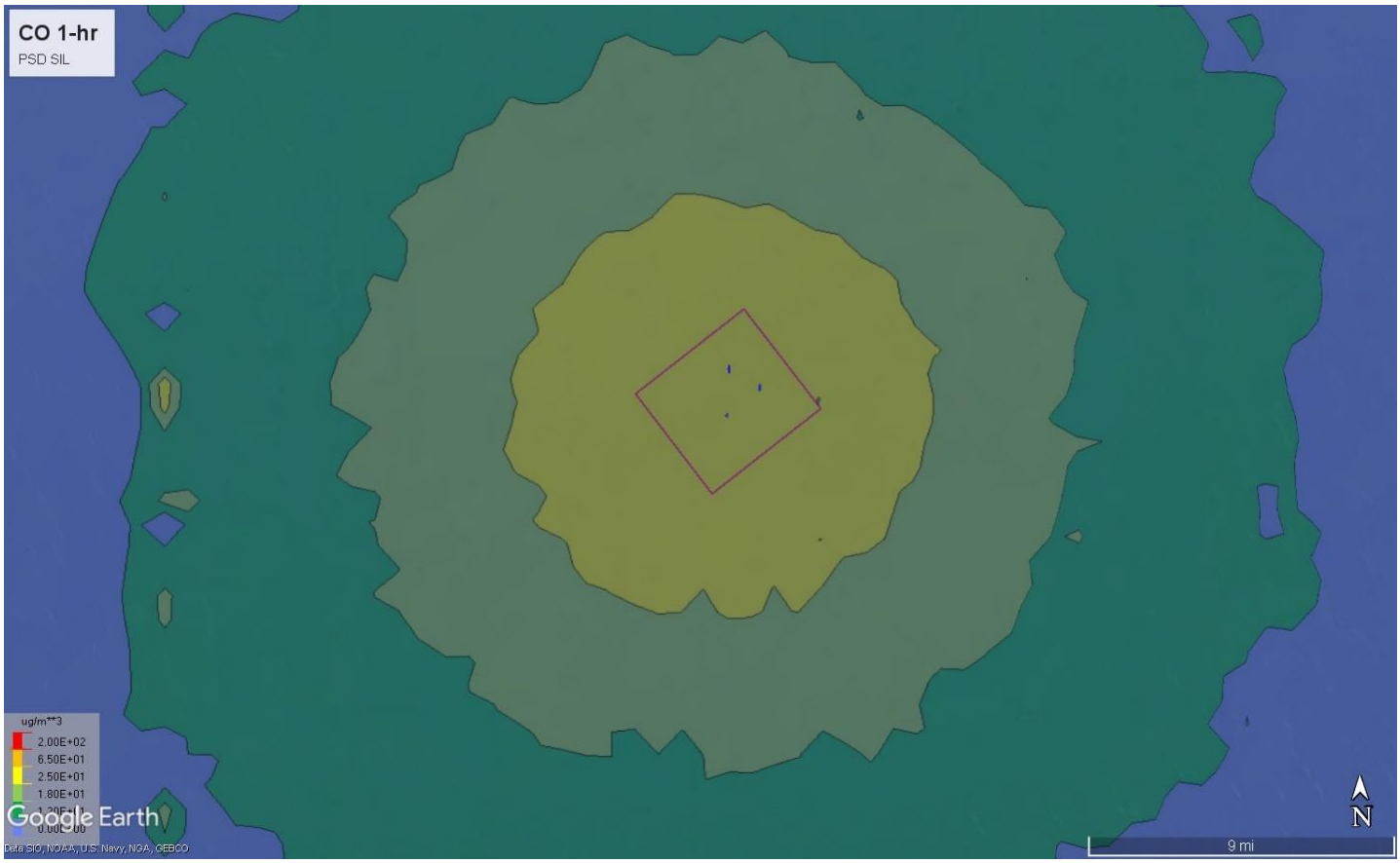

Figure B-2 CO 8-hr Averaging Period (SIL)

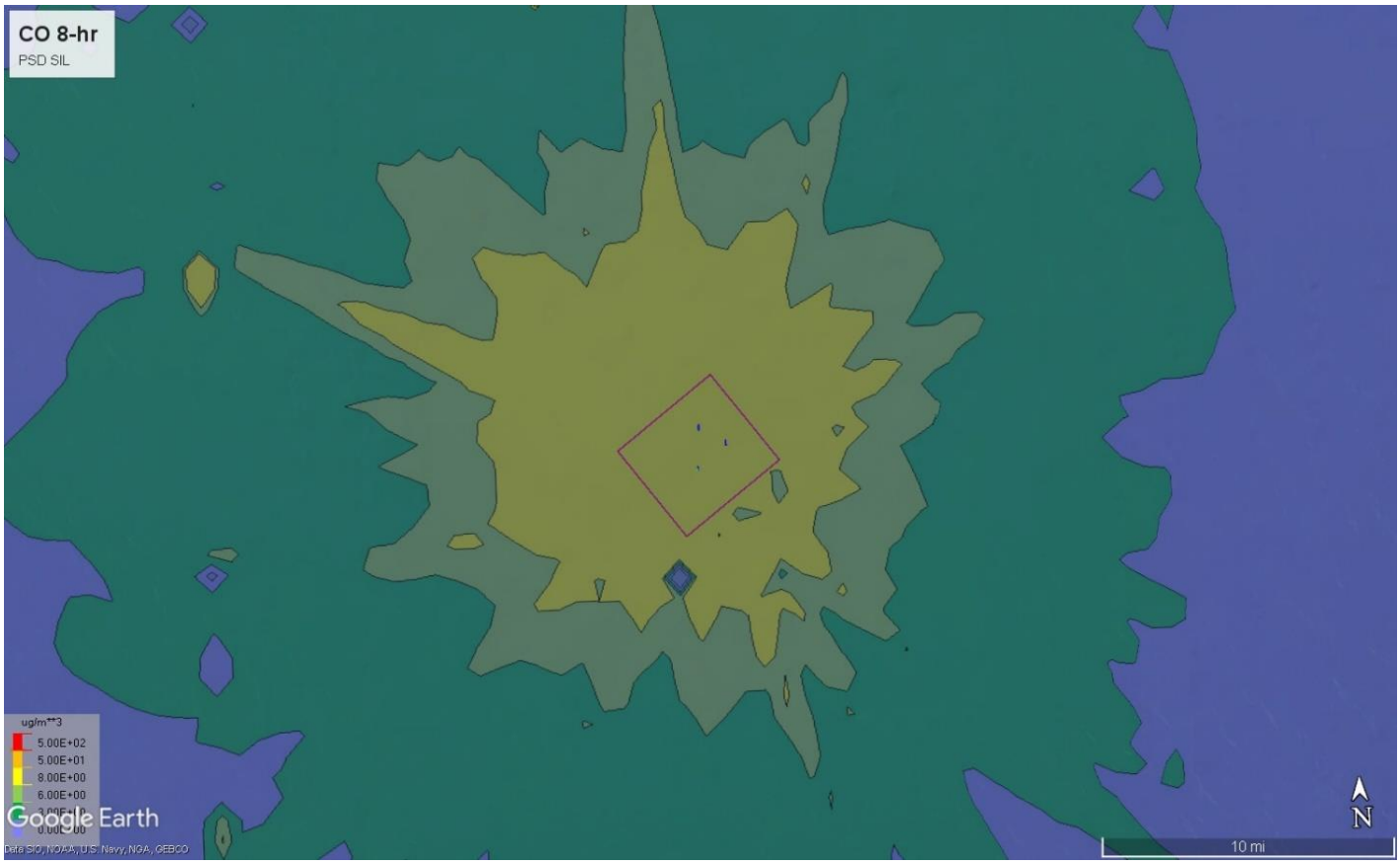

Figure B-3 NO_2 1-hr Averaging Period (SIL)

Figure B-4 NO_2 Annual (2012 Worst-Case) Averaging Period (SIL)

Figure B-5 $PM_{2.5}$ 24-Hour Averaging Period (SIL)

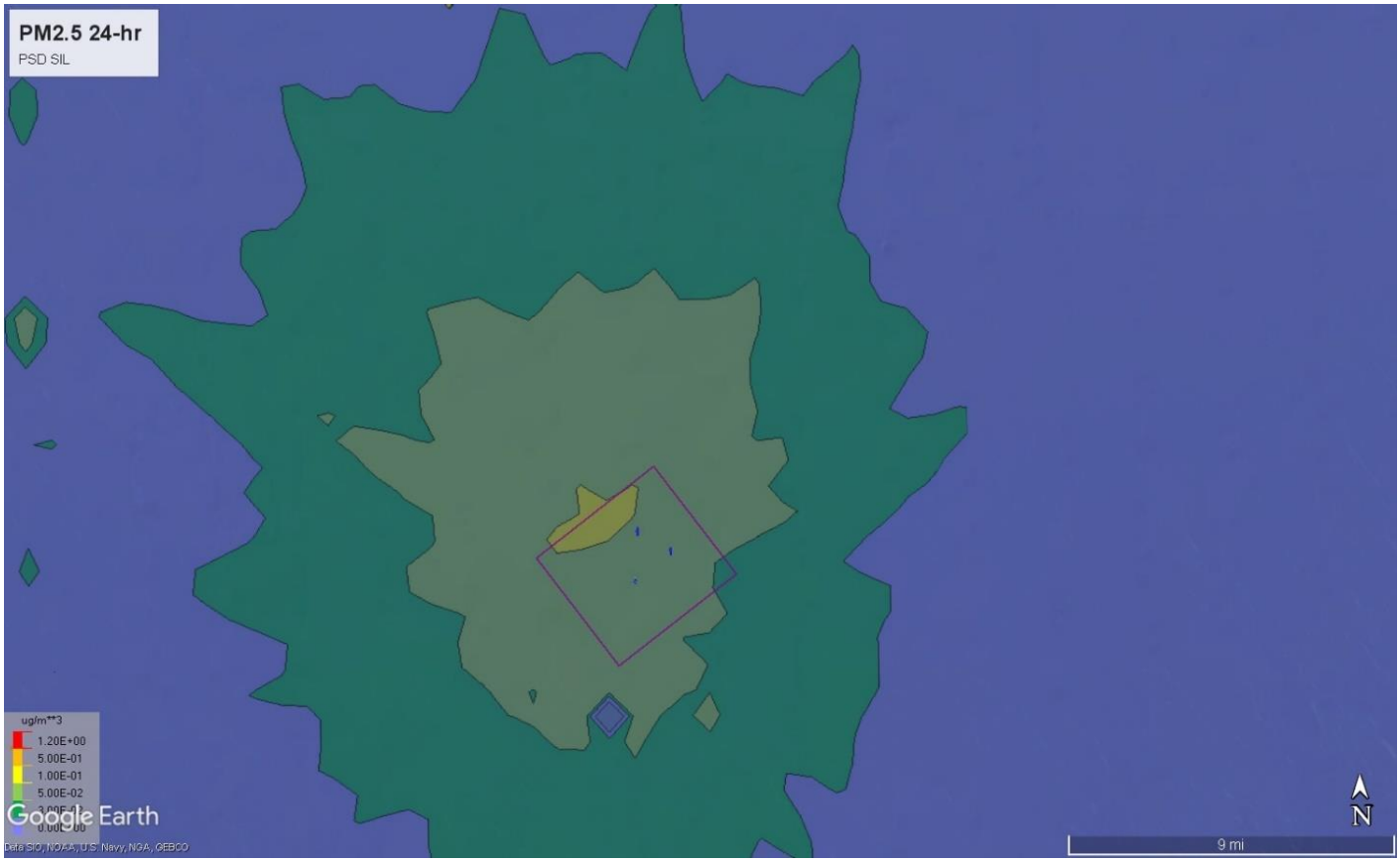

Figure B-6 $PM_{2.5}$ Annual Averaging Period (SIL)

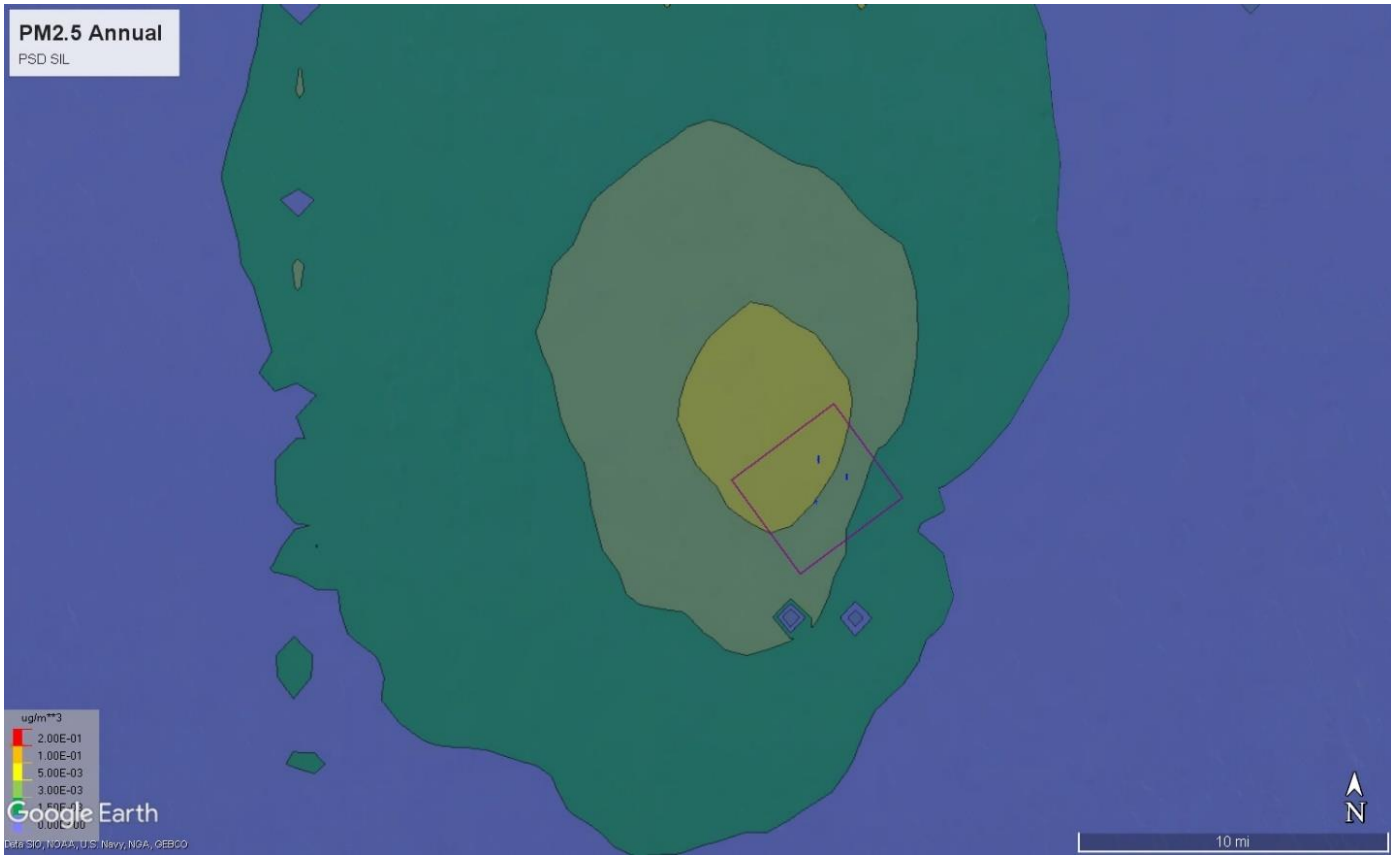

Figure B-7 PM_{10} 24-Hour Averaging Period (SIL)

Figure B-8 PM_{10} Annual (2012) Worst-Case Averaging Period (SIL)

TITLE V AIR OPERATING PERMIT APPLICATION

BLUE MARLIN OFFSHORE PORT LLC

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April 2023

Project 191001.0117

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY **1-1**
- **1.1 Air Permit Applicability Overview** **1-2**
- **1.2 Request for Permit Shield** **1-2**
- **1.3 Application Contents** **1-3**

2. PROJECT DESCRIPTION **2-1**
- **2.1 Project Overview** **2-1**
  - *2.1.1 Modified WC 509 Operations* *2-3*
  - *2.1.2 New Offshore Equipment for Marine Loading* *2-4*
- **2.2 Proposed Schedule** **2-6**

3. EMISSIONS QUANTIFICATION **3-1**
- **3.1 Potential Emissions Summary** **3-1**
- **3.2 Detailed Emissions Calculations** **3-2**
  - *3.2.1 Marine Loading* *3-2*
  - *3.2.2 Marine Loading – Uncaptured Emissions* *3-8*
  - *3.2.3 Marine Loading – Controlled Emissions by Vapor Combustion Units* *3-9*
  - *3.2.4 Marine Loading – Controlled Emissions by Low Pressure Flare* *3-10*
- **3.3 WC 509 Platform Support Equipment Emissions** **3-10**
  - *3.3.1 Natural Gas Generators* *3-10*
  - *3.3.2 High Pressure Flare* *3-11*
  - *3.3.3 Emergency Diesel Generator* *3-11*
  - *3.3.4 Platform Crane Engines* *3-12*
  - *3.3.5 Firewater Pump Engines* *3-13*
  - *3.3.6 Storage Tanks* *3-13*
  - *3.3.7 Fugitive Emissions* *3-14*
  - *3.3.8 Maintenance, Startup, and Shutdown* *3-15*

4. REGULATORY ANALYSIS **4-1**
- **4.1 Federal Permitting Programs** **4-1**
  - *4.1.1 New Source Review* *4-1*
  - *4.1.2 Title V Air Operating Permit Program* *4-3*
  - *4.1.3 State Permitting Program* *4-3*
- **4.2 Air Quality Regulations** **4-4**
  - *4.2.1 Federal Regulations* *4-4*
  - *4.2.2 State Regulations* *4-15*

5. PROPOSED CASE-BY-CASE REQUIREMENTS **5-1**
- **5.1 BACT Summary** **5-1**
- **5.2 VOC BACT** **5-1**
  - *5.2.1 Marine Loading Proposed Compliance Requirements* *5-2*
  - *5.2.2 Non-Emergency Natural Gas-Fired Engine-Driven Generators Proposed Compliance Requirements* *5-3*
  - *5.2.3 Emergency Diesel-Fired Firewater Pumps Proposed Compliance Requirements* *5-3*
  - *5.2.4 Emergency Diesel-Fired Engine-Driven Generators Proposed Compliance Requirements* *5-4*
  - *5.2.5 Diesel-Fired Crane Engines Proposed Compliance Requirements* *5-4*
  - *5.2.6 Fugitive Emissions Proposed Compliance Requirements* *5-4*

5.2.7 Storage Vessels Proposed Compliance Requirements 5-5
5.3 CO BACT 5-5
5.3.1 Non-Emergency Natural Gas-Fired Engine-Driven Generators Proposed Compliance Requirements 5-5
5.3.2 Emergency Diesel-Fired Firewater Pumps Proposed Compliance Requirements 5-6
5.3.3 Emergency Diesel-Fired Engine-Driven Generators Proposed Compliance Requirements . 5-6
5.3.4 Diesel-Fired Crane Engines Proposed Compliance Requirements 5-6
5.4 NO_X BACT 5-6
5.4.1 Non-Emergency Natural Gas-Fired Engine-Driven Generators Proposed Compliance Requirements 5-7
5.4.2 Emergency Diesel-Fired Firewater Pumps Proposed Compliance Requirements 5-7
5.4.3 Emergency Diesel-Fired Engine-Driven Generator Proposed Compliance Requirements .. 5-7
5.4.4 Diesel-Fired Crane Engines Proposed Compliance Requirements 5-8
5.5 PM_{10}/$PM_{2.5}$ BACT 5-8
5.5.1 Non-Emergency Natural Gas-Fired Engine-Driven Generators Proposed Compliance Requirements 5-8
5.5.2 Emergency Diesel-Fired Firewater Pumps Proposed Compliance Requirements 5-9
5.5.3 Emergency Diesel-Fired Engine-Driven Generator Proposed Compliance Requirements .. 5-9
5.5.4 Diesel-Fired Crane Engines Proposed Compliance Requirements 5-9
5.6 GHG BACT 5-9
5.6.1 Non-Emergency Natural Gas-Fired Engine-Driven Generators Proposed Compliance Requirements 5-10
5.6.2 Diesel-Fired Engines Proposed Compliance Requirements 5-10

APPENDIX A. SITE MAPS AND PLOT PLANS A-1

APPENDIX B. LDEQ AND PART 71 FORMS B-1

APPENDIX C. DETAILED EMISSIONS CALCULATIONS C-1

APPENDIX D. CERTIFICATE OF GOOD STANDING D-1

LIST OF FIGURES

Figure 2-1. Project Overview Map 2-2

Figure 2-2. Existing WC 509 Platform Complex 2-3

Figure 2-3. Schematic of the Proposed WC 509 Platform Complex 2-6

LIST OF TABLES

Table 2-1. DWP Components for Offshore Loading 2-5

Table 3-1. Potential Emissions Summary 3-1

Table 3-2. Marine Loading Emissions Specifications 3-4

Table 3-3. Summary of UPL by HAP, Liquid Mass Percent 3-7

Table 3-4. Summary of UPL by HAP, Vapor Mass Percent 3-7

Table 3-5. Crude Oil Vapor HAP Speciation 3-8

Table 3-6. Potential VOC and HAP Mass Emissions from Uncaptured Marine Loading 3-9

Table 3-7. Storage Tank Representation 3-14

Table 4-1. PSD Major Stationary Source Determination 4-2

Table 4-2. Project Emissions Increase Evaluation 4-2

Table 5-1. Proposed VOC BACT Summary 5-2

Table 5-2. Proposed CO BACT Summary 5-5

Table 5-3. Proposed NO_x BACT Summary 5-7

Table 5-4. Proposed $PM_{10}/PM_{2.5}$ BACT Summary 5-8

Table 5-5. Proposed GHG BACT Summary 5-10

1. EXECUTIVE SUMMARY

Blue Marlin Offshore Port LLC (the Applicant) is proposing to develop the Blue Marlin Offshore Port (BMOP) Project (Project) in the Gulf of Mexico (GOM) to provide United States (U.S.) crude oil loading services onto very large crude carriers (VLCCs), and other crude oil carriers, for export to the global market.

The primary purpose of the Project will be to provide a safe and reliable long-term supply of crude oil for export to the global market. To accomplish this purpose, BMOP will repurpose an existing subsea pipeline within the Stingray Pipeline System to transport crude oil to the proposed deep water port (DWP). This DWP will be located in federal waters within Outer Continental Shelf (OCS) West Cameron Lease Block (WC) 509, WC 508, and East Cameron (EC) Block 263. At the DWP location, VLCCs, or other crude oil carriers (collectively referred to as "crude oil carriers" or "VLCCs"in this report), will moor at one of two Catenary Anchor Leg Mooring (CALM) Buoys, a type of Single Point Mooring (SPM) buoy system. Floating crude oil hoses will be connected to the buoy to support crude oil loading. Up to 275 VLCCs may be loaded per year.

In response to EPA's September 13, 2022, request, BMOP has added vapor capture and control for the loading of the VLCCs. The vapor capture and control system will include floating vapor return hoses, which will be connected to the VLCCs along with the floating crude oil hoses. Displaced vapors from the crude oil carrier will be routed through the floating vapor return hoses back to the CALM buoys. Separate submerged hoses will carry the vapors from the buoys to the pipeline end manifold (PLEM) at the sea floor, and a looped subsea vapor return pipeline will route the vapors from the PLEMs back to the WC 509 Platform Complex. A dock safety skid and vapor blowers will be added to the WC 509 Platform Complex. The captured vapors (expected 99% capture efficiency) will be routed to three (3) vapor combustion units (VCUs), which will have an average destruction and removal efficiency (DRE) for volatile organic compounds (VOCs) of 95%.

The proposed project will require a DWP license in accordance with the Deep Water Port Act (DWPA). The U.S. Environmental Protection Agency (EPA) is identified as a cooperating agency in the review of a DWP license, in accordance with Title 33 of the Code of Federal Regulations (CFR) §148.3(d). The DWPA also requires evaluation of the DWP in accordance with the Clean Air Act (CAA). The Project consists of both onshore and offshore components. As defined in 33 CFR §148.5, a deep water port is:

> *"[A]ny fixed or floating manmade structures other than a vessel, or any group of structures, located beyond State seaward boundaries that are used or are intended for use as a port or terminal for the transportation, storage, or further handling of oil or natural gas for transportation to any State, except as otherwise provided in the Deepwater Port Act of 1974, as amended, and for other uses not inconsistent with the purposes of the Deepwater Ports Act, including transportation of oil or natural gas from the United States' OCS… Must be considered a 'new source' for the purposes of the Clean Air Act…"*

Title V of the CAA requires air operating permits for major sources, which are regulated under 40 CFR §70 (state administered program) and §71 (federally administered program). The operating permits outline the emission limits, applicable requirements, compliance, and operating conditions applicable to the emission units at a major source. The Project will be a Title V major source since potential emissions exceed the Title V major source threshold for oxides of nitrogen (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and hazardous air pollutants (HAPs) and will require a federal Title V operating permit

under Part 71. For sources located outside of the state seaward boundary on the OCS, EPA Region 6 administers the Title V permit program, consistent with adjacent state regulations.

As such, this Title V air operating permit application is being re-submitted to the EPA Region 6 in accordance with 40 CFR §71.5(a)(1)(ii), to include the required vapor capture and control per EPA's September 13, 2022, letter. At the request of EPA Region 6, this application includes Louisiana Department of Environmental Quality (LDEQ) application forms and applicable Part 71 forms (Appendix B of this application).

1.1 Air Permit Applicability Overview

The DWP site will be approximately 82 statute miles off the coast of Cameron Parish, Louisiana, with an approximate water depth of 156 to 162 feet.[1] The nearest Parish onshore is Cameron Parish, Louisiana. Cameron Parish is designated by EPA as "attainment" or "unclassifiable" with the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants.[2] Therefore, the Project is not subject to Nonattainment New Source Review (NNSR) permitting requirements for any criteria pollutants.

Based on potential air emissions calculations, the Project will be a major source under Title V as potential emissions of NO_X, CO, VOC, and HAPs are greater than the applicable major source thresholds. Therefore, the project will require a federal Title V air operating permit under Part 71.

1.2 Request for Permit Shield

Section 504(f) of the Clean Air Act Amendments (CAAA) of 1990 defines the permit shield provision, whereby the permitting authority is empowered to provide that compliance with a Title V permit shall be deemed in compliance with all other applicable provisions of the Act in effect, provided that applicability was addressed in the permit application. A provision may be included in the major source air operating permit stating that compliance with the conditions of the major source air operating permit shall be deemed in compliance with all applicable requirements (as of the date of permit issuance) provided that the following conditions are met:

- Such applicable requirements are identified and included in the permit; and
- The permitting authority, in acting on the permit application which addresses applicability of the requirement, determines in writing that other requirements specifically identified are not applicable to the source, and the permit includes the determination or concise summary thereof.

BMOP is requesting through this application that the permit shield provisions be included in the initial Title V air operating permit consistent with this regulation. Therefore, BMOP has specifically addressed in summary all regulations potentially applicable at the time of this application. Furthermore, this application also provides non-applicability determinations for certain regulations to assist EPA Region 6 in determining in writing that identified regulations are not applicable to operations at the Project. Note that this non-applicability review is limited to those regulations for which there may be some question of applicability specific to the Project.

[1] The DWP will be approximately 99 statute miles from where the pipe leaves the shore, also in Cameron Parish, Louisiana.

[2] 40 CFR §81.319

1.3 Application Contents

This application includes all information required pursuant to 40 CFR §71.5(a)(2):

- Section 2 includes a detailed description of the Project with an overview of the project emission sources;
- Section 3 provides additional project details defining the characteristics, design capacity, and expected operating schedule for the equipment associated with the Project along with the detailed description of emissions estimation methodologies;
- Section 4 outlines the analysis of potentially applicable state and federal air regulations;
- Section 5 includes a summary of the proposed best available control technology (BACT) determination and proposed BACT requirements, evaluated in the Prevention of Significant Deterioration (PSD) application, submitted concurrently under separate covers;
- Appendix A includes site maps and plot plans for the Project;
- Appendix B provides LDEQ air permit application forms and the relevant Part 71 forms including: Initial Compliance Plan and Compliance Certification (Form I-Comp), Fee Calculation Worksheet (Form FEE), and Certification of Truth, Accuracy, and Completeness (Form CTAC), including the required information of 40 CFR §71.5(c);
- Appendix C provides the detailed emission calculations described in Section 3; and

The Responsible Official (RO) has completed the certification of truth, accuracy, and completeness, based on information and belief formed after reasonably inquiry, in accordance with 40 CFR §71.5(d).

Based on the requirements under 40 CFR §71.9, each permit application requires an application fee that is based upon the actual emissions from the Project. Form FEE (5900-03) of Appendix B provides the application fee calculation worksheet. Since the Project is not yet constructed and operating, the Project has zero actual emissions. Accordingly, the initial application fee is calculated as zero. BMOP will remit payment of fees owed under the fee schedule established pursuant to 40 CFR §71.9(b) after start-up of the Project, based on actual emissions.

2. PROJECT DESCRIPTION

The Applicant is proposing to develop the BMOP Project in the GOM to load crude oil into crude oil carriers for export to the global market.

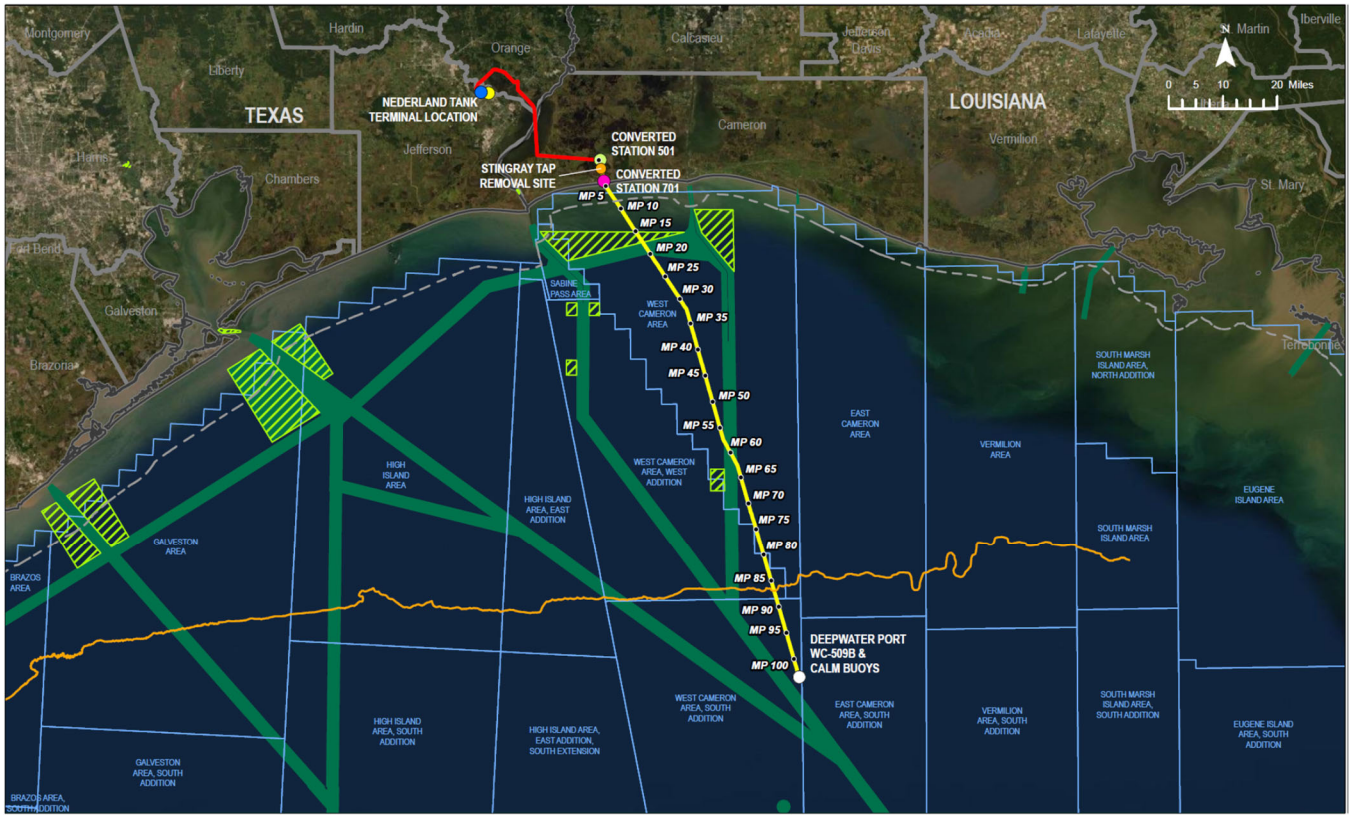
The primary purpose of the Project is to provide a safe and reliable long-term supply of crude oil for export to the global market. To fulfill the primary purpose, the Project must be capable of fully loading the international fleet of crude-carrying marine vessels to accommodate the safe and efficient transport of crude. Accordingly, the Project requires a DWP that can accommodate the draft and berth of a fully loaded VLCC with the ability to load in varying meteorological conditions. This ensures safety in transfer and transit by minimizing risks of transportation incidents (e.g., spills, allisions, collisions). It is not possible for existing onshore terminals in the GOM to fully load a VLCC due to limited draft. There are only a couple existing onshore terminals in the GOM that can partially load a VLCC; loading is completed offshore via reverse lightering. The proposed DWP design avoids the inefficiency and cost of idled time at a fixed port for partial VLCC loading while offering the benefit of avoiding dock-constrained ports to free up dock space for other commodities. This approach also resolves the logistical challenges and added vessel traffic of reverse lightering while mitigating the risks and additional environmental impacts of multiple loadings for a single fully-loaded VLCC.

2.1 Project Overview

The proposed Project utilizes many existing facilities, both onshore and offshore. Crude oil for export at BMOP will be transported out of the existing Energy Transfer Nederland Terminal, LLC terminal and storage facility in Jefferson County, Texas (Nederland Terminal or NT). This terminal is connected to multiple crude oil pipelines from across the U.S. In addition, an affiliate of the Applicant owns the Stingray Pipeline System (Stingray) and has confirmed that its existing subsea pipeline and offshore platforms are suitable for conversion to facilitate crude oil export from a DWP in the northern GOM.

Crude oil will be routed from the NT pump station through a new 42-inch outer diameter (OD) onshore pipeline to the existing Stingray Mainline at the existing Station 501, and from there through the existing 36" OD Stingray Mainline to the existing offshore platform complex at WC 509. The following figure presents a map of the Project. This figure is reproduced in Appendix A with additional detail.

Figure 2-1. Project Overview Map



The DWP will be located in federal waters within and adjacent to the OCS in WC 509, WC 508 and EC 263. The DWP will be approximately 82 statute miles off the coast of Cameron Parish, Louisiana, with an approximate water depth of 162 feet.[3] The crude oil will be metered at the pump station on the NT and on the existing WC 509B Platform and routed through two Crude Oil Loading Lines to PLEMs located on the seafloor below two CALM buoys located in WC 508 and in EC 263. From each PLEM, the crude oil will be routed to its respective floating CALM buoy through submerged flexible hoses. VLCCs will moor at a CALM buoy, retrieve and connect the floating crude oil hoses connected to the CALM buoy and the crude oil will then route from the Buoy to the VLCC for loading. Up to 275 VLCCs will load per year.

The crude oils that will be exported range from light to heavy grade crudes and will be sent from the existing NT facility. The Project will accommodate loading up to 275 VLCCs with the use of two CALM buoys. Loading will not occur at both buoys simultaneously. During the time necessary for a loaded vessel to disconnect and depart the safety zone, and for a subsequent vessel to approach the same buoy, moor, and attach to the loading hoses, the second buoy will be loading a moored ship at up to 80,000 bbl/hr. The loading operation will then switch to the alternate buoy, providing the ability to continuously load one ship at a time. Displaced vapors during loading will be routed from the crude oil carrier to the CALM buoys through floating vapor return hoses. Submerged vapor hoses will carry the vapors from the buoys to the PLEM at the sea floor, where a looped subsea vapor return pipeline will route the vapors from the PLEMs to the VCUs at the WC 509 Platform Complex.

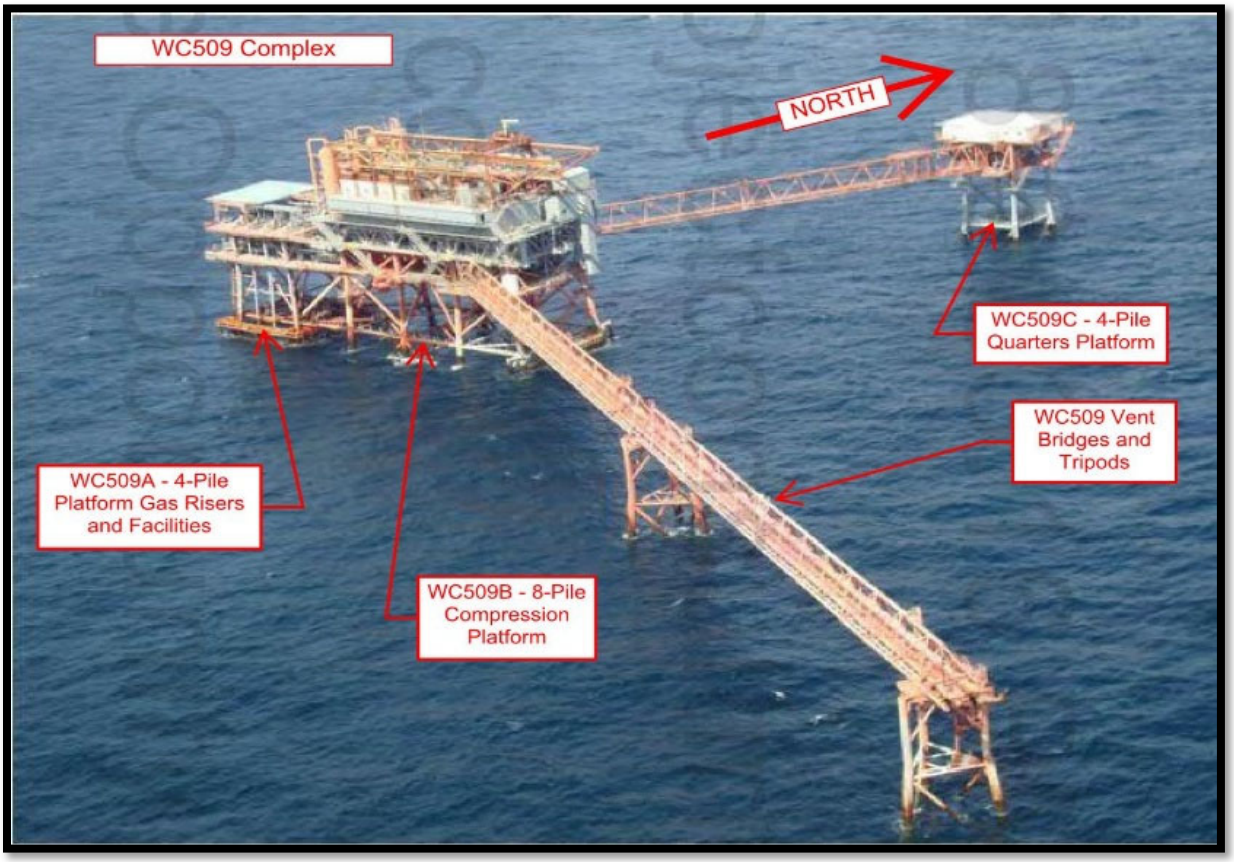
[3] The DWP will be approximately 99 statute miles from where the pipe leaves the shore, also in Cameron Parish, Louisiana.

This application is for the aggregated stationary sources subject to the Title V air permitting requirements at the proposed offshore DWP. Site maps and plot plans at WC 509 are included in Appendix A to this application. The following subsections identify the stationary emissions sources.

2.1.1 Modified WC 509 Operations

Flow through the existing offshore Stingray Pipeline will be reversed to transfer crude oil from the existing Station 501 onshore to the existing WC 509 platform complex.

Figure 2-2. Existing WC 509 Platform Complex



This existing platform complex is near existing shipping channels currently used by large seafaring crude oil vessels with a water depth >160 feet. The natural gas lines currently on the WC 509A platform will be redirected subsea to the Sea Robin Pipeline system.

Following EPA's September 13, 2022, letter, BMOP has revised the Project design to include vapor capture and control with VCUs. The deck of the WC 509A platform will be stripped and raised, such that it can house dock safety units and three VCU stacks. With this design update, the Project will include added ability to access offshore natural gas supply currently routed through either the existing Stingray system to the WC 509A platform, or through a new connection to receive gas from the Sea Robin Pipeline system. Together, these gas supplies will serve basic platform utilities and vapor combustion assist gas without necessitating that all utilities be powered by fuel delivered from shore.

The Project will repurpose the WC 509B platform, removing all current equipment in natural gas service, and replacing it with support facilities for the crude oil DWP. The revised design will no longer retain any of the existing equipment – the existing natural gas compressors, four gas inlet scrubbers, piping and risers on 509A, and all other existing emissions units will be removed. To support the crude oil export operation, new components for oil service and other ancillary utility equipment will be installed at the WC 509 platform complex. The following new emission sources will be added at WC 509:

- Vapor controls
  - Three (3) vapor combustion units (VCUs) with an average VOC DRE of 95%;
  - One (1) low pressure flare for vapor line pigging operations at the Vent Bridge Tripod;
- One (1) high pressure flare for natural gas line pigging operations at the Vent Bridge Tripod;
- Fugitive Emissions from crude oil piping components;
  - New 36" OD risers;
  - Batch switching/pigging capability;
  - Crude oil meter and meter prover;
- Crude oil 1,000 barrel (bbl) capacity surge vessel and surge system;
- Fugitive Emissions from lube oil, waste oil, and sump collection systems;
- Ancillary utility equipment;
  - Two (2) redundant 1,736 kilowatt (kW) natural gas-fired engine-driven generators, Caterpillar G3516C, or similar;
  - One (1) 336 kW emergency diesel-fired engine-driven generator;
    - Primary diesel fuel tank;
  - Two (2) 475 horsepower (hp) diesel-fired engine-driven cranes, Caterpillar G13, or similar;
    - Two (2) diesel fuel tanks (one for each crane); and
  - Two (2) 650 hp emergency diesel-fired engine-driven firewater pumps, one on WC 509B and one on WC 509C; and
  - Helicopter re-fueling tank.

2.1.2 New Offshore Equipment for Marine Loading

From the existing WC 509 platform complex, new equipment will be added offshore to serve the DWP, including:

- **Two new CALM Buoys**
  - The CALM buoys will be anchored to the seafloor using a multiple-point, chain anchoring system capable of accommodating mooring forces exerted by a VLCC or other large seafaring vessel during loading operations. Each CALM buoy will have two 24-in diameter floating crude oil hoses for vessel loading. Additionally, two floating vapor return hoses will be connected to the VLCC's vapor system to capture displaced vapors, with the other end connected to a second swivel path on each CALM Buoy. These floating hoses will be similar to the crude oil loading hoses, but for vapor return. All hoses will be approximately 1,500 feet long.
- **Two new PLEMs** connecting to each of the CALM buoys. One PLEM per buoy will transport crude oil from the seafloor up to the buoy through dual 24-inch undersea flexible hoses. The other PLEM transports returned vapors from the buoy down to the seafloor through dual 24-inch undersea flexible hoses.
- **Two lateral subsea Crude Oil Loading Pipelines** installed from the existing WC 509 Platform Complex to the PLEM locations, one for each PLEM. The Crude Oil Loading Pipelines to PLEM / CALM Buoy No. 1 and PLEM / CALM Buoy No. 2 will be 6,325 feet long and 6,085 feet long, respectively.
- **Four lateral subsea Vapor Return Pipelines** installed from the existing WC 509 Platform Complex to the PLEM locations, two for each PLEM in a loop for pigging. The Vapor Return Pipelines will transport

returned vapors from the PLEM at the seafloor to the WC 509 Platform Complex, where they are routed to the three (3) VCUs. The Vapor Return Pipelines to PLEM / CALM Buoy No. 1 and PLEM / CALM Buoy No. 2 will be 6,422 feet long and 6,085 feet long, respectively.

The location of the new equipment for marine loading in comparison to the existing WC 509 Platform Complex is delineated in the following table.

Table 2-1. DWP Components for Offshore Loading

Component	Latitude (N) (degrees minutes seconds)	Longitude (W) (degrees minutes seconds)	Water Depth (feet)
WC 509 Platform Complex[a]	28° 26' 00.01"	93° 00' 15.23"	162
CALM Buoy No. 1 and PLEM (WC 508)	28° 27'03.29"	93° 00' 12.33"	162
CALM Buoy No. 2 and PLEM (EC 263)	28° 26' 34.37"	92° 59' 19.21"	159

a. Riser #1.

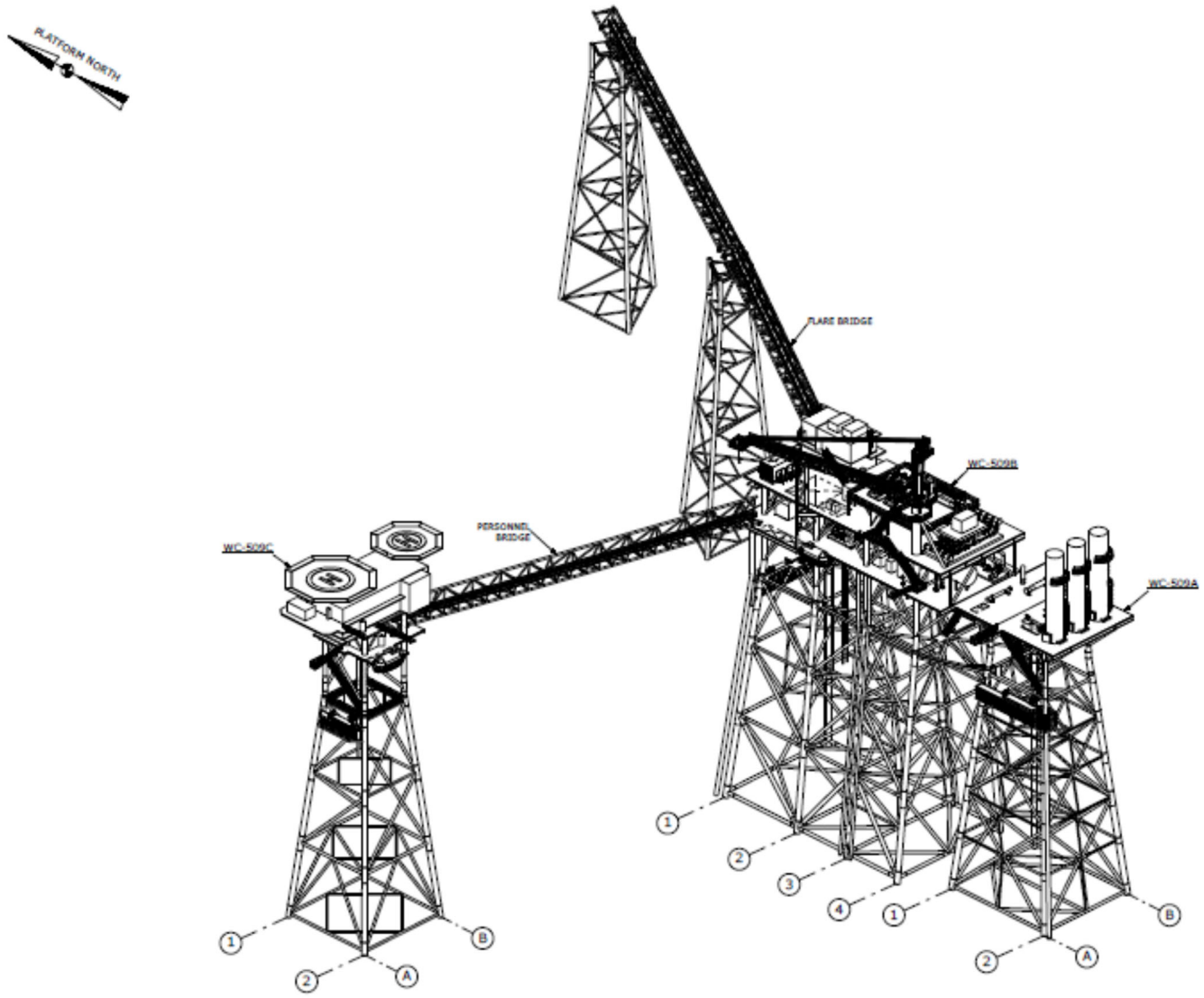
CALM Buoy No. 1 is 6,325 feet from its WC 509B riser, while CALM Buoy No. 2 is 6,085 feet from its WC 509B riser. VLCCs will moor to the CALM buoys. As an SPM system, the vessels will be able to weathervane around the CALM buoy while moored and loading. No fixed structures or platforms will be located within ~1 mile of the buoy to allow safe vessel movement. This capability is an important design characteristic due to the DWP location of approximately 82 statute miles (71 nautical miles) from the nearest point on land. This location is classified as "exposed waters" by the United States Coast Guard (USCG), as it is greater than 20 nautical miles from the nearest harbor of safe refuge.[4] As well, the National Weather Service (NWS) provides distinct wind, wave, and weather forecasts for "offshore waters" greater than 60 nautical miles from shore, in comparison to "coastal water" forecasts inside of 60 nautical miles in the GOM.[5]

Floating and flexible 24-inch diameter hoses approximately 1,500 feet long will be installed for loading crude oil from the CALM buoy to the VLCC, and returning vapor displaced during loading from the VLCC to the CALM buoy. The floating crude oil hoses will be recovered by one of the DWP support vessels, lifted to the VLCC loading manifold, and connected to the receiving flange. The floating vapor hoses will be lifted and connected to the VLCC vapor system. The floating hoses will simply float on the surface of the water and will weathervane depending on the current when not being used for loading. The floating hoses will contain a butterfly valve on the end that will be utilized to isolate the hose after loading is complete and prior to placing the hoses back in the water. Additionally, a blind flange will be installed to further prevent any potential contamination or leakage while the hose is floating and waiting for the next VLCC to be loaded.

[4] 46 CFR §170.050.

[5] https://www.nhc.noaa.gov/abouttafbprod.shtml

Figure 2-3. Schematic of the Proposed WC 509 Platform Complex



The schematic is presented again in Appendix A to this application.

The BMOP Project is unique from other sources and contemporary crude oil export operations because of its conversion of existing offshore facilities to support new CALM buoys in loading crude oil for export into an international fleet of crude oil carriers.

2.2 Proposed Schedule

Refurbishment of the existing WC 509 Platform Complex will begin in March 2024. The on-site installation of the crude oil subsea pipelines, PLEMs, and CALM buoy systems is expected to commence by 2025. Construction is expected to complete in 4Q2026, with start up of the facilities occurring thereafter.

3. EMISSIONS QUANTIFICATION

3.1 Potential Emissions Summary

The potential emissions of NO_X, CO, VOC, sulfur dioxide (SO_2), PM_{10}, $PM_{2.5}$, hydrogen sulfide (H_2S), sulfuric acid mist (H_2SO_4), hazardous air pollutants (HAPs), and GHG, represented as CO_2e is shown below.

Table 3-1. Potential Emissions Summary

	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	PM_{10}[6] (tpy)	$PM_{2.5}$ (tpy)	H_2S (tpy)	H_2SO_4 (tpy)	HAPs (tpy)	CO_2e (tpy)
Marine Loading										
Uncaptured Crude Oil Loading	--	--	1,604	--	--	--	0.70	--	89.9	--
VCU #1	143	263	260	4.25	4.99	4.99	0.11	--	14.6	157,510
VCU #2	143	263	260	4.25	4.99	4.99	0.11	--	14.6	157,510
VCU #3	143	263	260	4.25	4.99	4.99	0.11	--	14.6	157,510
Low Pressure Flare	4.03	8.05	52.9	0.32	--	--	--	--	2.96	4,815
Supporting Platform Operations										
Natural Gas High Pressure Flare	1.03	2.06	0.14	1.2E-3	--	--	--	--	0.013	886
Natural Gas Generators (x2)	11.2	5.17	6.29	0.05	0.80	0.80	--	2.3E-3	4.22	12,871
Emergency Diesel Generator	0.15	0.13	0.15	0.02	8.6E-3	8.6E-3	--	5.0E-4	6.1E-4	25.8
Platform B Cranes (x2)	2.05	12.0	0.97	1.48	0.21	0.21	--	0.05	0.06	2,383
Platform B Firewater Pump Engine	0.21	0.19	0.21	0.02	0.01	0.01	--	7.2E-4	3.6E-4	37.2
Platform C Firewater Pump Engine	0.21	0.19	0.21	0.02	0.01	0.01	--	7.2E-4	3.6E-4	37.2
Aviation Fuel Tank	--	--	5.1E-4	--	--	--	--	--	7.7E-5	--
Platform B Cranes Diesel Tank #1	--	--	1.9E-3	--	--	--	--	--	2.7E-4	--
Platform B Cranes Diesel Tank #2	--	--	1.9E-3	--	--	--	--	--	2.7E-4	--
Primary Diesel Tank	--	--	8.5E-3	--	--	--	--	--	1.2E-3	--
Surge Tank #1	--	--	3.73	--	--	--	--	--	0.07	--
Total Fugitive Emissions	--	--	23.7	--	--	--	5.1E-3	--	2.96	1,211
Total	**449**	**817**	**2,473**	**14.7**	**16.0**	**16.0**	**1.04**	**0.05**	**144**	**494,797**

[6] PM_{10} and $PM_{2.5}$ emissions are represented as the sum of filterable $PM_{10}/PM_{2.5}$ and condensable emissions.

3.2 Detailed Emissions Calculations

Potential emissions were calculated for the stationary offshore sources by using the following calculation methodologies.

3.2.1 Marine Loading

Emissions from marine loading occur as a result of displaced vapors from loading crude oil into a marine vessel. There are three emissions pathways as a result of the loading activity:

- Uncaptured loading vapors;
- Captured loading vapors controlled by a VCU; and
- Captured loading vapors that are routed to a low pressure flare during vapor pipeline pigging.

Each of these emissions pathways are addressed in this subsection, with the calculation methodology for characterizing the total vapor and the vapor constituents addressed first.

3.2.1.1 Marine Loading Vapors - VOC

VOC emissions from marine loading of crude oil are calculated based on the maximum hourly loading rate (gallons per hour [gal/hr]) and Equations 2 and 3 of EPA's AP-42, Section 5.2 (07/08), which was developed specifically for loading crude oil into ships and ocean barges,[7] and has also been utilized by EPA in the development of the National Emission Standards for Hazardous Air Pollutants (NESHAP) Subpart Y for onshore/near shore loading of crude oil.[8] The Project will load only crude oil, and no refined products. In addition to EPA's explicit direction in AP-42 to utilize Equations 2 and 3 for crude oil loading into ocean-going ships, this methodology is consistent with other marine loading of crude and permitting determinations in Louisiana,[9] which is the nearest onshore state. To align with the nearest state consistent with the DWPA,[10] and based on Louisiana's recent determinations for crude loading into ships, Equations 2 and 3 are most appropriate to estimate emissions for the Project. Furthermore, BMOP has referenced footnote A of Table 5.2-3 in AP-42, which identifies that VOC emissions are 15% lower than the factor in the table, in consideration of the non-VOC loading vapors in the referenced arrival emissions factors for inerted marine vessel tanks.[11]

The application of Equations 2 and 3 is described below.

---

[7] AP-42 Chapter 5.2 Transportation and Marketing of Petroleum Liquids, 6/08.

[8] "*We agree with the commenter that the emission factors for ships and barges, as applicable to the type of marine vessel being loaded, should be considered for estimating VOC and HAP emissions. We have revised the emission estimates using the barge and ship emission factors from AP–42,"* referenced from 76 FR 22582, April 21, 2011, left column. Also see Subpart Y: Email from Michelle Herman, Chevron to Steve Shedd, EPA Chevron Pipe Line Nederland TX Emissions Data for MVL, 5/18/2010, ID: EPA-HQ-OAR-2010-0600-0044, which uses AP-42 Eq. 2 and 3 for crude oil loading into ships, and Eq. 1 for gasoline loading.

[9] See examples: Part 70 Permit No. 2520-00033-V-14 for International Matex Tank Terminals – IMTT – St. Rose, Louisiana, 8/14/2019, based on crude loading emissions from Eq. 2 and 3 from application for Title V Revision, dated June 3, 2019, and also Part 70 Permit No. 2560-00034-V9 for Sugarland Pipeline Station/Terminal, Shell Pipeline Company, LP, St. James, Louisiana, based on crude loading emissions from Eq. 2 and 3.

[10] 33 USC §1518(b).

[11] It should be noted that BMOP's crudes will be "weathered." This refinement considers the arrival emission factor (the characteristics of the vessel's tank vapors – which, in part, is related to the vessel's prior cargo).

$$C_L = C_A + C_G$$

Where:

$C_L = Total\ Loading\ Loss, pounds\ per\ 1000\ gallons\ \left(\frac{lb}{10^3 gal}\right) of\ crude\ oil\ loaded$

$C_A = Arrival\ emission\ factor, contributed\ by\ vapors\ in\ the\ empty\ tank\ compartment\ before\ loading, \frac{lb}{10^3 gal}\ of\ crude\ oil\ loaded$

$C_G = Generated\ emission\ factor, contributed\ by\ evaporation\ during\ loading, \frac{lb}{10^3 gal}\ of\ crude\ oil\ loaded$

Continuing to conservatively use the average arrival emission factor for an uncleaned ship/ocean barge tank, but following footnote A of AP-42 Table 5.2-3, C_A is determined to be:

$$C_A = TOC\ EF\ \left(\frac{lb}{10^3 gal}\right) \times (1 - nonVOC\ fraction) = 0.86 \times (1 - 0.15) = 0.731 \left(\frac{lb}{10^3 gal}\right)$$

The generated emissions factor, C_G is calculated based on Equation 3 of AP-42, Section 5.2, as described below.

$$C_G = 1.84 \times (0.44 \times P - 0.42) \times \frac{MG}{T}$$

Where:

$P = True\ vapor\ pressure\ of\ loaded\ crude\ oil, psia$

$M = Molecular\ weight\ of\ vapors, \frac{lb}{lb - mol}$

$G = Vapor\ growth\ factor, 1.02\ (dimensionless)$

$T = Temperature\ of\ vapors, °R$

BMOP estimates a maximum hourly loading rate of 80,000 barrels per hour (bbl/hr) of crude oil.[12] Note that with the implementation of vapor capture, it is not possible to sustain the maximum hourly loading rate for continuous loading every hour of the year. Accordingly, the maximum annual throughput is 605 million barrels per year (bbl/yr), based on the maximum annual loading schedule into marine vessels with vapor capture.

To calculate the VOC loading loss rate (in lb/10^3 gal), maximum hourly and annual average crude loading temperatures and crude true vapor pressures are used, based on Project design specifications. Because the crude oil will be subsea for approximately 100 nautical miles, the long-term temperature representative of the sea floor was used to estimate the loading temperatures.[13] The molecular weight of the crude oil (liquid and vapor) is based on AP-42, Chapter 7, Table 7.1-2 (06/20). A summary of the characteristics used to calculate VOC emissions is provided in Table 3-2.

3.2.1.2 Marine Loading Vapors – H_2S

Emissions of H_2S from marine loading are based on the hourly maximum and annual average H_2S content in the crude oil, and the following mass balance equation.

[12] 80,000 bbl/hr is approximately 3,360,000 gal/hr.

[13] Temperature data from ROMS Texas A&M University Outputs, Location: WC509, Depth 151 feet. Long-term average of 72.66°F used for annual average conditions and a maximum of 90°F used for short-term maximum conditions (max of dataset is 85.4°F.

$$H_2S\ Emission\ Rate\ \left(\frac{lb\ H_2S}{lb\ VOC}\right) = \frac{X}{1x10^6} \times \frac{M_{crude}}{M_{H2S}} \times \frac{M_{H2S}}{M_{Vapor}} \times k$$

Where:

$X = Crude\ H_2S\ Content, parts\ per\ million\ by\ weight\ (ppmw)$

$M_{crude} = Molecular\ weight\ of\ crude\ liquid, \left(\frac{lb}{lb-mol}\right)$

$M_{H_2S} = Molecular\ weight\ of\ H_2S, \left(\frac{lb}{lb-mol}\right)$

$M_{Vapor} = Molecular\ weight\ of\ crude\ vapor, \left(\frac{lb}{lb-mol}\right)$

$k = Vapor\ to\ liquid\ H_2S\ partition\ factor$[14]

A summary of the characteristics used to calculate H_2S emissions are also provided in the table below.

Table 3-2. Marine Loading Emissions Specifications

	Maximum Hourly	Annual Average
Crude Loading Rate (bbl/hr)	80,000	80,000
TOC Arrival Emission Factor	0.86	0.86
VOC Arrival Emission Factor	0.731	0.731
Loading Temperature (°R)	550	532
Vapor Molecular Weight (lb/lbmol)	50	50
Liquid Molecular Weight (lb/lbmol)	207	207
True Vapor Pressure [TVP] (psia)[15]	10.99	9.00
Liquid H_2S Partition	25	21
H_2S Concentration (ppmw)[16]	125	5
H_2S Molecular Weight (lb/lbmol)	34.1	34.1

3.2.1.3 Marine Loading Vapors – HAP

Emissions of HAP are based on an identified maximum crude oil vapor HAP speciation, by individual HAP, provided in weight percent (wt%) of the vapor. These maximum individual HAP concentrations were determined from thirteen samples of various crude types at the Nederland Terminal from May and June 2020 and analyzed per Method D7900, *Standard Test Method for Determination of Light Hydrocarbons in Stabilized Crude Oils by Gas Chromatography*.[17] The analytical results provided an extensive speciation of the crude oil, of which >99.9% was identified as VOCs. From these 13 samples, the average total HAP concentration in the liquid was 3.2 wt%. This identifies the expected average HAP concentration to be less than 5%, by weight, in the liquid.

[14] Per the Petroleum Processing Handbook, McGraw-Hill, New York, Figure 12-71, page 12-93.

[15] Maximum short-term and annual average true vapor pressure aligned with the permit limits for the origination of the crude oil for the BMOP Project – the Nederland Terminal. Note that the purpose of the project is to load a variety of both heavy and light crude oils, so using the permit limits is a conservative estimate of potential emissions for the Project.

[16] Hourly H_2S concentration aligned with permit limits for the origination of the crude oil for the BMOP Project – the Nederland Terminal. Annual mass H_2S emissions calculated from a conservative assumption of 5 ppmw. The average of all samples from Nederland (>3000 samples) is 1.31 ppmw.

[17] 49 CFR §171.7(h)(45).

For estimating potential emissions, the concentration in the vapor phase was calculated. Consistent with AP-42, Chapter 7.1.4 (06/2020), Raoult's Law was followed to determine the HAP content in the vapor phase of the crude oil from the HAP content in the liquid phase. Raoult's Law states that the mole fraction in the liquid of a speciated component, when multiplied by the vapor pressure of that component, is equal to the partial pressure of that component, or:

$$P_i = (P)(x_i)$$

Where:

$P_i = partial\ pressure\ of\ component\ i, psia$

$P = vapor\ pressure\ of\ pure\ component\ i\ at\ the\ average\ daily\ liquid\ surface\ temperature, psia$

$x_i = liquid\ mole\ fraction\ of\ component\ i, \frac{lb-mole}{lb-mole}$

The vapor pressure of each HAP species was determined using published Antoine Coefficients at the average daily temperature.

The liquid mole fraction was determined from the liquid weight fraction of the component in the samples per:

$$x_i = \left(\frac{Z_{Li} M_L}{M_i}\right)$$

Where:

$x_i = liquid\ mole\ fraction\ of\ component\ i, \frac{lb-mole}{lb-mole}$

$Z_{Li} = weight\ fraction\ of\ component\ i\ in\ the\ liquid, lb/lb$

$M_L = molecular\ weight\ of\ liquid\ stock, \left(\frac{lb}{lb-mol}\right)$

$M_i = molecular\ weight\ of\ component\ i, \left(\frac{lb}{lb-mol}\right)$

The vapor mole fraction was determined by:

$$y_i = \frac{P_i}{P_{VA}}$$

Where:

$y_i = vapor\ mole\ fraction\ of\ component\ i, \frac{lb-mole}{lb-mole}$

$P_i = partial\ pressure\ of\ component\ i, psia$

$P_{VA} = total\ vapor\ pressure\ of\ liquid\ mixture, psia$

The weight fractions in the vapor phase can then be determined from the mole fractions in the vapor phase.

$$Z_{Vi} = \frac{y_i M_i}{M_V}$$

Where:

$Z_{Vi} = vapor\ weight\ fraction\ of\ component\ i, lb/lb$

$y_i = vapor\ mole\ fraction\ of\ component\ i, \frac{lb-mole}{lb-mole}$

$M_i = molecular\ weight\ of\ component\ i, \left(\frac{lb}{lb-mol}\right)$
$M_V = molecular\ weight\ of\ vapor\ stock, \left(\frac{lb}{lb-mol}\right)$

The resulting total HAP in the vapor averaged 2.4% for all 13 samples.

In order to ensure a conservative representation of potential emissions on a short-term basis, the 99% upper prediction limit (UPL) was calculated for each individual HAP identified in the 13 samples. The UPL is a value derived from widely accepted and commonly used statistical principles and represents the upper end of a prediction interval.[18] EPA notes that the UPL is a statistical methodology used "as the primary tool to account for emissions variability when setting emissions standards." The UPL calculates the average emissions limitation achieved over time by the best performing source. [19]

> *In the context of development of MACT floors, the UPL is a value, calculated from a dataset, that identifies the average emissions level that a source or group of sources is meeting and would be expected to meet a specified percent of the time that the source is operating.*
>
> *In other words, the 99 percent UPL is the level of emissions that we are 99 percent confident is achieved by the average source represented in a dataset over a long-term period based on its previous, measured performance history as reflected in short term stack test data.*
>
> *In sum, the UPL predicts the level of emissions that the sources upon which the floor is based are expected to meet over time, considering both the average emissions level achieved as well as emissions variability and the uncertainty that exists in the determination of emissions variability given the available, short-term data.*

Following EPA's preferred approach to determining the MACT standard that can be met by a unit with emissions at the average level of the best performing source, BMOP has completed the calculation of the 99 percent UPL value for each individual HAP identified from the 13 crude oil samples. The following equation presents the approach to the UPL calculations for a dataset with a lognormal distribution (Equation 2 from *EPA's Response to Remand of the Record for Major Source Boilers, July 14, 2014*).

$$UPL_{100-(\alpha\times100)} = e^{\hat{\mu}+\frac{\hat{\sigma}^2}{2}} + \frac{z_{(1-\alpha)}}{m}\sqrt{me^{2\hat{\mu}+\hat{\sigma}^2}\left(e^{\hat{\sigma}^2}-1\right) + m^2e^{2\hat{\mu}+\hat{\sigma}^2}\left(\frac{\hat{\sigma}^2}{n}+\frac{\hat{\sigma}^4}{2(n-1)}\right)}$$

Where: α = level of significance expressed as a decimal (e.g., 1% significance = 0.01); note that confidence level $= 100 - (\alpha \times 100)$;
e = base of the natural logarithm ≈ 2.718282;
$\hat{\mu}$ = mean of the log transformed sample data $\left(= \frac{1}{n}\sum_{i=1}^{n} \ln(x)_i\right)$;
$\hat{\sigma}^2$ = variance of the log transformed sample data $\left(= \frac{1}{n}\sum_{i=1}^{n} (\ln(x)_i - \hat{\mu})^2\right)$;

[18] National Institute of Standards and Technology, *NIST/SEMATECH e-Handbook of Statistical Methods*, <http://www.itl.nist.gov/div898/software/dataplot/refman1/auxillar/predlimi.htm>.

[19] Memorandum from Stephen D. Page, Director, Office of Air Quality Planning and Standards, U.S. EPA, to Docket ID No. EPA-HQ-OAR-2002-0058, "EPA's Response to Remand of the Record for Major Source Boilers," July 14, 2014.

z = z score, the one-tailed z value of the z distribution for a specific level of significance;
m = number of sample values used to calculate the average;
n = number of samples.

The results of the UPL of the HAP mass percent in the liquid crude are presented in the following table.

Table 3-3. Summary of UPL by HAP, Liquid Mass Percent

HAP	99% UPL (wt. %, liquid)
Hexane	3.09
Benzene	0.46
Toluene	1.10
Ethylbenzene	0.29
1,2,4-Trimethylbenzene	0.76
1,3—Dimethylbenzene	0.79
1,4-Dimethylbenzene	0.57
1,2-Dimethylbenzene	0.37
Cumene	0.08
Total HAP	**7.50**

The liquid mass percent was converted to the mass percent in vapor, based on the calculated vapor speciation using the extended results of the 13 samples and Raoult's Law. The calculation of vapor pressure utilized Antoine's equation, referenced at equation 1-26 of AP-42, Chapter 7.1 (06/2020), and Antoine's constants determined for each species at a temperature of 72.66 °F. The 99% UPL was then determined for the vapor mass percent, as shown in the table below.

Table 3-4. Summary of UPL by HAP, Vapor Mass Percent

HAP	99% UPL (wt. %, vapor)
Hexane	4.09
Benzene	0.34
Toluene	0.29
Ethylbenzene	0.02
1,2,4-Trimethylbenzene	0.01
1,3—Dimethylbenzene	0.05
1,4-Dimethylbenzene	0.03
1,2-Dimethylbenzene	0.02
Cumene	0.003
Total HAP	**4.86**

BMOP used the higher of the 99% UPL vapor weight percent from the 13 samples, or the Nederland Terminal Permit basis for each individual HAP, whichever was greater. The result is a conservative estimate for each individual HAP and the total HAP (which is the sum of the highest values for each individual HAP).

BMOP has used the following crude oil vapor HAP speciation to estimate emissions.

Table 3-5. Crude Oil Vapor HAP Speciation

HAP	Vapor Weight %
Hexane	4.09
Benzene	0.80
Toluene	0.36
Ethylbenzene	0.05
1,2,4-Trimethylbenzene	0.01
1,3-dimethylbenzene	0.05
1,4-dimethylbenzene	0.03
1,2-dimethylbenzene (Xylene)	0.21
i-propylbenzene (Cumene)	0.01
Biphenyl	0.00002
Cresols	0.001
Naphthalene	0.001
Phenol	0.001
Total HAP	5.60

Hourly and annual VOC emissions are multiplied by each HAP speciation, above, to determine the hourly and annual HAP mass emission rates.

3.2.1.4 Marine Loading Vapors– GHG

None of the 13 samples of varying crude types identified methane (CH_4) or carbon dioxide (CO_2) in the crude. Although produced crude may have some amount of methane, methane is highly volatile and will quickly be released in vapor prior to being loaded into a marine vessel in the BMOP DWP, after many steps of production (which is initially extracted at pressure, then stored in atmospheric tanks where the majority of light ends flash off), processing, storage, and hundreds of miles of transmission. Referred to as "weathering," it is typical for the lightest volatile compounds, including methane and carbon dioxide, to be released well before reaching a storage terminal. This is evident in that none of the 13 samples contained even a small fraction of methane or carbon dioxide in the crude at the Nederland Terminal.

Accordingly, GHG emissions from crude oil loading at the BMOP project are not expected.

3.2.2 Marine Loading – Uncaptured Emissions

This submittal reflects the new Project design, including capture and control of vapors from marine loading. BMOP expects the vapor capture system collection efficiency to be 99%. Accordingly, 1% of marine loading results in uncaptured emissions.

In addition, 40 CFR 63 Subpart Y provides a "maintenance allowance," or a period of time that the DWP is allowed to perform maintenance on the loading berth without controlling emissions from marine tank vessel

loading operations.[20] BMOP has estimated an annual maintenance allowance of 629 hours, as presented in more detail in Section 4.2.1.2.4 of this application. During these 629 hours, it is assumed that all loading emissions will be uncaptured at the annual average emissions rate.

Table 3-6. Potential VOC and HAP Mass Emissions from Uncaptured Marine Loading

Pollutant	Max Hourly Loading Vapors (lb/hr)	Uncaptured Annual Emissions (tpy)
VOC	4,989	1,604
HAP speciation:		
Hexane	204.0	65.6
Benzene	39.93	12.8
Toluene	17.73	5.70
Ethylbenzene	2.48	0.80
1,2,4-Trimethylbenzene	0.53	0.17
1,3-dimethylbenzene	2.38	0.76
1,4-dimethylbenzene	1.66	0.53
1,2-dimethylbenzene (Xylene)	10.36	3.33
i-propylbenzene (Cumene)	0.29	0.09
Biphenyl	0.001	0.0003
Cresols	0.04	0.012
Naphthalene	0.03	0.010
Phenol	0.07	0.024
Total HAP	279.5	89.9

3.2.3 Marine Loading – Controlled Emissions by Vapor Combustion Units

The Project will operate three (3) vapor combustion units (VCUs) to control the captured vapor emissions from marine vessel loading operations. BMOP predicts that each VCU will have a destruction and removal efficiency (DRE) of 95% during routine operations.

NO_x and CO emissions are calculated based on the emission factor estimated by the VCU vendor. Filterable and condensable PM emissions are estimated based on emissions factors from AP-42 Chapter 1, Table 1.4-2 (07/98), *Emissions Factors for Natural Gas Combustion*. Filterable PM emissions are assumed to be equivalent to PM_{10} and $PM_{2.5}$ emissions. SO_2 and H_2S emissions are based on an annual average H_2S concentration of 5 ppmw from crude oil compositions provided by BMOP. It is assumed that 95% of the H_2S is combusted, and 100% of the combusted H_2S is oxidized to form SO_2. VOC and HAP emissions are also based on the crude oil compositions, discussed previously for marine loading vapor composition, and the predicted DRE of 95% (of the 99% captured vapors, less the maintenance allowance). GHG emissions of CO_2, CH_4, and N_2O are based on emission factors provided in 40 CFR 98, Subpart C, Tables C-1 and C-2, for

[20] Definition of "maintenance allowance" per 40 CFR 63.561.

"various types of fuel". The CO_2e emission rate was calculated based on the CO_2, CH_4, and N_2O GWP's of 1, 25, and 298, respectively.

To calculate emissions for heat rate based emission factors (lb/MMBtu or kg/MMBtu), a crude oil vapor HHV of 1,456 MMBtu/MMscf and VCU maximum heat input rate of 218 MMBtu/hr were used. These values were derived from crude oil specifications at 100% vessel loading by BMOP, which represents a short-term maximum. The average heat input rate of an entire vessel is expected to be lower.

To conservatively estimate emissions from the VCU stacks, BMOP assumes that each VCU will operate continuously at 100% loading.

3.2.4 Marine Loading – Controlled Emissions by Low Pressure Flare

The Project will operate one (1) low pressure flare to be utilized to control routine pigging of the crude oil carrier vapor lines following marine vessel loading. BMOP predicts that the low pressure flare will receive vapor at a rate of 3.5 MMscf/day.

NO_x and CO emissions estimated for high Btu gas stream combustion in flares that are not steam assisted. VOC and HAP emissions are found using the crude oil vapor composition from 13 crude oil samples, an assumption that all vapors are VOC, and a flare DRE of 98%. SO_2 emissions are also found from the H_2S content in the provided crude oil vapor composition. It is assumed that 100% of the H_2S in the vapor is oxidized to form SO_2. GHG emissions of CO_2, CH_4, and N_2O from vapor combustion are based on emission factors provided in 40 CFR 98, Subpart C, Tables C-1 and C-2, for "various types of fuel". The CO_2e emission rate was calculated based on the CO_2, CH_4, and N_2O GWP's of 1, 25, and 298, respectively.

Based on current project design specifications, the low pressure flare is operated in a 1-hour period following loading of each vessel. Up to 275 VLCCs are loaded at the WC 509 Platform per year. Thus, emissions from the low pressure flare are based on an annual operating time of 275 hours.

3.3 WC 509 Platform Support Equipment Emissions

The following subsections describe the emissions calculation methodology for equipment on the WC509 Platform Complex that supports the proposed DWP.

3.3.1 Natural Gas Generators

The Project will operate two (2) natural gas-fired generators. BMOP design identifies that the make/model of each generator will be similar to a Caterpillar G3516C, each rated at approximately 2,000 hp. To conservatively estimate emissions from the proposed units, a maximum power of 2,328 hp was used, per the manufacturer's specification sheet at 100% load.

Emissions from NO_X, CO, and VOC are based on the vendor expected emissions for a Caterpillar G3516C engine with an oxidation catalyst, in grams per horsepower-hour (g/hp-hr). Emissions from formaldehyde are limited to 14 ppmvd or less at 15% O_2, based on Table 2a of NESHAP Subpart ZZZZ.[21] Emissions from CO_2 and CH_4 are estimated based on the manufacturer's specifications sheet, in grams per kilowatt hour (g/kW-hr). Emissions from filterable PM_{10}, $PM_{2.5}$, condensable PM, SO_2, and the remaining HAPs are estimated based on emission factors from AP-42 Chapter 3, Table 3.2-2 (07/00), *Uncontrolled Emission Factors for 4-Stroke Lean Burn Engines*, in pounds per million British thermal units (lb/MMBtu). Filterable

[21] Table 2a of NESHAP Subpart ZZZZ for four-stroke lean burn (4SLB) stationary RICE.

PM emissions are assumed to be equivalent to filterable PM_{10} and $PM_{2.5}$ emissions. H_2SO_4 emissions are assumed to be 5% of SO_2 emissions. The natural gas specific emission factor from 40 CFR 98 Subpart C, Table C-2, *Default CH_4 and N_2O Emission Factors for Various Types of Fuel,* is used to estimate N_2O emissions, in kilograms per MMBtu (kg/MMBtu). The CO_2e emission rate is calculated based on the CO_2, CH_4, and N_2O emission rates, weighted according to their global warming potentials (GWP) of 1, 25, and 298, respectively.

To calculate emissions for heat rate based emission factors (lb/MMBtu or kg/MMBtu), a natural gas higher heating value (HHV) of 1,020 British thermal units per standard cubic foot (Btu/scf)[22] and average brake-specific fuel consumption rate of 17,820 scf per hour (scf/hr) are used.[23]

Based on the current Project design, only one engine will be operating at any given time to continuously power the sources of the DWP platform. Therefore, potential annual emissions are based on the continuous operation of a single engine at 100% load.

3.3.2 High Pressure Flare

The Project will operate one (1) high pressure flare to be utilized during periodic pigging of the natural gas line to the WC 509 Platform. BMOP predicts that the high pressure flare will receive natural gas at a rate of 32 MMscf/day, and conservatively estimates 1 event per year.

NO_x and CO emissions estimated for high Btu gas stream combustion in flares that are not steam assisted. VOC, HAP, and uncombusted CH_4 emissions are found using the Stingray system natural gas composition and a flare DRE of 98%. SO_2 emissions are also found from the H_2S content in the provided natural gas composition. It is assumed that 100% of the H_2S in the natural gas is oxidized to form SO_2. GHG emissions of CO_2, CH_4, and N_2O from natural gas combustion are based on emission factors provided in 40 CFR 98, Subpart C, Tables C-1 and C-2, for natural gas. The CO_2e emission rate is calculated based on the CO_2, CH_4, and N_2O GWP's of 1, 25, and 298, respectively.

Based on current project design specifications, the high pressure flare is only operated during natural gas line pigging. Each pigging event lasts around 11 hours. Pigging is expected to occur once per 7 years but is conservatively assumed to occur once per year in the emissions calculations.

3.3.3 Emergency Diesel Generator

The Project will operate one (1) emergency, diesel-fired generator. BMOP design identifies that the emergency generator will be rated at approximately 336 kW (~450 hp).

Emissions from filterable PM, NO_X, VOC, and CO are estimated based on the emissions standards provided in 40 CFR §60.4202(a)(2) and Table 3 of Appendix I to 40 CFR 1039, in g/kW-hr.[24] Filterable PM emissions are assumed to be equivalent to PM_{10} and $PM_{2.5}$ emissions. HAP emissions are estimated based on emission factors from AP-42 Chapter 3, Tables 3.3-1 and 2 (10/96), *Emission Factors for Uncontrolled Gasoline and*

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[22] Per footnote b of AP-42, Table 3.2-2.

[23] Per the manufacturer's specification sheet at 100% load.

[24] Per 40 CFR §60.4202(a)(2), for 2007 model year or later emergency stationary compression ignition internal combustion engines with a rated power greater than or equal to 50 hp, less than 3,000 hp, with a displacement less than 10 liters per cylinder, and that are not fire pump engines. It is conservatively assumed that NO_X and VOC emissions are equivalent to the NMHC+NO_X emission limit.

Diesel Industrial Engines, in lb/MMBtu. AP-42 Chapter 3.3 does not provide an emission factor for condensable PM, therefore, the condensable PM emission factor provided in AP-42, Table 3.4-2, *Emission Factors for Large Uncontrolled Stationary Diesel Engines,* is conservatively used. SO_2 and H_2SO_4 emissions are based on a diesel fuel sulfur content of 0.1%. It is estimated that 98% of the sulfur is oxidized to SO_2 and the remaining 2% is hydrolyzed to H_2SO_4. GHG emissions of CO_2, CH_4, and N_2O are based on emission factors provided in 40 CFR §98, Subpart C, Tables C-1 and C-2, for distillate fuel oil No. 2. The CO_2e emission rate is calculated based on the CO_2, CH_4, and N_2O GWP's of 1, 25, and 298, respectively.

To calculate emissions for heat rate based emission factors (lb/MMBtu or kg/MMBtu), a distillate fuel oil HHV of 19,300 British thermal units per pound (Btu/lb) and average brake-specific fuel consumption (BSFC) rate of 7,000 British thermal units per horsepower-hour (Btu/hp-hr) are used. [25]

The emergency diesel-fired generator will only operate during periods where both natural gas generators are unavailable or for maintenance and readiness testing. Therefore, to estimate potential emissions, BMOP conservatively assumes that the emergency generator will not operate more than 100 hours per year, operating at 100% load.

3.3.4 Platform Crane Engines

The Project will operate a number of platform cranes for various types of operation. Based on current design specifications for the Project, the following diesel-fired crane engines will be located at the WC 509 platform complex:

- Two (2) 354 kW (~475 hp) diesel engines.

Emissions from filterable PM, NO_X, CO, and VOC are estimated based on the emissions standards provided in 40 CFR §60.4204(b), in g/kW-hr.[26] To conservatively estimate emissions from the crane engines, emissions of PM, NO_X, and VOC are multiplied by the appropriate Not to Exceed (NTE) multiplier provided in 40 CFR §1039.101(e), which, for engines with a NO_X standard less than 2.5 g/kW-hr and PM standard less than 0.07 g/kW-hr is 1.5. Filterable PM emissions are assumed to be equivalent to PM_{10} and $PM_{2.5}$ emissions.

Emissions from HAPs are estimated based on emission factors from AP-42 Chapter 3, Tables 3.3-1 and 2 (10/96), *Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines*. AP-42 Chapter 3.3 does not provide an emission factor for condensable PM, therefore, the condensable PM emission factor provided in AP-42, Table 3.4-2, *Emission Factors for Large Uncontrolled Stationary Diesel Engines,* is conservatively used. SO_2 and H_2SO_4 emissions are based on a diesel fuel sulfur content of 0.1%. It is estimated that 98% of the sulfur is oxidized to SO_2 and the remaining 2% is hydrolyzed to H_2SO_4. GHG emissions of CO_2, CH_4, and N_2O are based on emission factors provided in 40 CFR §98, Subpart C, Tables C-1 and C-2, for distillate fuel oil No. 2. The CO_2e emission rate is calculated based on the CO_2, CH_4, and N_2O GWP's of 1, 25, and 298, respectively.

To calculate emissions for heat rate based emission factors (lb/MMBtu or kg/MMBtu), a distillate fuel oil HHV of 19,300 Btu/lb and average BSFC rate of 7,000 Btu/hp-hr are used. [27]

[25] Per footnote e of AP-42 Table 3.4-1.

[26] Per 40 CFR §60.4204(b) and 40 CFR §1039.101, for 2014 model year or later combustion ignition internal combustion engines between 130 kW to 560 kW.

[27] Per footnote c of AP-42 Table 3.3-1.

To conservatively estimate emissions from the crane engines, BMOP assumes that each crane engine will operate up to 4,380 hours per year.

3.3.5 Firewater Pump Engines

The Project will operate two (2) firewater pump engines. Current design specifications for the Project identify that the engines will be rated at approximately 485 kW (~650 hp).

Emissions from filterable PM, NO_X, CO, and VOC are estimated based on the emissions standards provided in Table 4 of NSPS Subpart IIII[28] and 40 CFR §60.4204(b), in g/kW-hr.[29] Filterable PM emissions are assumed to be equivalent to PM_{10} and $PM_{2.5}$ emissions.

Emissions from HAPs are estimated based on emission factors from AP-42 Chapter 3, Tables 3.3-1 and 2 (10/96), *Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines*. AP-42 Chapter 3.3 does not provide an emission factor for condensable PM, therefore, the condensable PM emission factor provided in AP-42, Table 3.4-2, *Emission Factors for Large Uncontrolled Stationary Diesel Engines,* is conservatively used. SO_2 and H_2SO_4 emissions are based on a diesel fuel sulfur content of 0.1%. It is estimated that 98% of the sulfur is oxidized to SO_2 and the remaining 2% is hydrolyzed to H_2SO_4. GHG emissions of CO_2, CH_4, and N_2O are based on emission factors provided in 40 CFR §98, Subpart C, Tables C-1 and C-2, for distillate fuel oil No. 2. The CO_2e emission rate is calculated based on the CO_2, CH_4, and N_2O GWP's of 1, 25, and 298, respectively.

To calculate emissions for heat rate based emission factors (lb/MMBtu or kg/MMBtu), a distillate fuel oil HHV of 19,300 Btu/lb and average BSFC rate of 7,000 Btu/hp-hr are used. [30]

The emergency firewater pump engines will only operate during periodic maintenance testing and during emergencies. Therefore, to estimate potential emissions, BMOP conservatively assumes that the firewater pump engines will not operate more than 100 hours per year, operating at 100% load.

3.3.6 Storage Tanks

The Project will operate various fuel and petroleum liquid storage tanks. Current design specifications for the Project predict that the following storage tanks will be located at each platform:

- Platform B
  - Two (2) 4,400 gallon diesel storage tanks associated with each platform crane.
  - One (1) 18,000 gallon primary diesel storage tank.
  - One (1) 42,000 gallon crude oil surge tank.
- Platform C
  - One (1) 3,000 gallon aviation fuel (estimated as jet kerosene) tank.

[28] Per 40 CFR §60.4205(c) for firewater pump engines with a displacement of less than 30 liters/cylinder between 225 kW and 450 kW. Conservatively assume that NO_X and VOC emissions are equivalent to the NMHC+NO_X emissions limit.

[29] Per 40 CFR §60.4204(b) and 40 CFR §1039.101, for 2014 model year or later combustion ignition internal combustion engines between 130 kW to 560 kW.

[30] Per footnote c of AP-42 Table 3.3-1.

TankESP™ software was utilized to estimate potential annual emissions consistent with the methodology of AP-42 Chapter 7.1 using the following dimensions and usage assumptions.

Table 3-7. Storage Tank Representation

Tank	Tank Dimensions				Volume (gal)	Max. Filling Rate (gal/hr)	Annual Throughput (gal/yr)	Orientation
	L (ft)	W (ft)	H (ft)	Dia. (ft)				
Crane Diesel Storage Tank #1	--	--	30	5	4,400	400	114,400	Vertical
Crane Diesel Storage Tank #2	--	--	30	5	4,400	400	114,400	Vertical
Primary Diesel Storage Tank	16	15.48	16	--	18,000	400	468,000	Horizontal
Crude Oil Surge Tank	47.5	12.67	47.5	--	42,000	80,000	42,000	Horizontal
Aviation Fuel Tank	10	--	--	6.67	3,000	200	13,000	Horizontal

The chemical characteristics for jet kerosene and diesel fuel were based on standard TankESP™ defaults, while the chemical characteristics for crude oil were based on the same annual average values as described for loading emissions, provided in Table 2-3 above. It was assumed that all tanks will have fixed roofs and will be operated continuously.

3.3.7 Fugitive Emissions

Fugitive emissions were calculated based on the synthetic organic chemical manufacturing industry (SOCMI) average emission factor (in pounds per hour [lb/hr])[31], using the following equation.

$$E_{VOC} = F_A \times WF_{VOC} \times N$$

Where:

$E_{VOC} = Emission\ rate\ of\ VOC\ from\ all\ equipment\ in\ the\ stream, \frac{lb}{hr}$

$F_A = SOCMI\ average\ emission\ factor, \frac{lb}{hr}$

$WF_{VOC} = Weight\ fraction\ of\ VOC\ in\ the\ stream, \%$

$N = number\ of\ components\ in\ the\ stream$

This factor was chosen to ensure a conservative representation of the collection of piping components in various services (i.e. crude oil, diesel, natural gas, vapor etc) at the WC 509 DWP. It should be noted that no reduction from these average emissions factors has been applied for these estimates, to ensure a conservative representation. Actual emissions will be much lower, as piping components will be monitored and repaired, if found to be leaking, based on the applicable leak detection and monitoring requirements.

The total number of piping components for each applicable stream are based on current design estimates for the Project. The different streams are categorized as gas/vapor or light liquid service based on the contents of the stream. The total number of components are then multiplied by the appropriate SOCMI emission factor. For piping components servicing natural gas streams, it is assumed that the components

[31] As provided in EPA's Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017 https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf

are in gas/vapor service. For piping components servicing diesel fuel, crude oil, or aviation fuel (assumed to be equivalent to jet kerosene), it is assumed that the components are in light liquid service.

To determine the VOC emission rate, the stream is multiplied by the VOC wt% of the stream. For components in natural gas service, the total VOC composition of the stream is based on an April 13, 2020 sample at the DWP platform. For components in diesel fuel or jet kerosene service, the total VOC composition is consistent with the TankESP™ defaults. For components in crude oil service, the total VOC composition is based on the maximum vapor wt% used for crude oil loading emissions calculations.

Similar to VOC emissions, HAP emissions for the fugitive components were calculated using the same approach as above. Fugitive emissions also consider H_2S emissions from components in crude oil service and GHG emissions from components in natural gas service, using the same methodology as above. Annual emissions for all fugitive components are based on continuous operation (i.e. 8,760 hours of operation).

3.3.8 Maintenance, Startup, and Shutdown

BMOP has evaluated potential emissions not already identified above that may occur during maintenance, startup, and shutdown (MSS). In accordance with 40 CFR § 3.562(b)(6) of NESHAP Subpart Y, BMOP is applying for a "maintenance allowance" of 629 hours, annually that the DWP may perform maintenance on the loading berths without controlling emissions from marine tank vessel loading operations. During the maintenance allowance, the displaced vapors from crude oil loading activities would exhaust through the crude oil carrier's vent mast riser. The emissions during the maintenance allowance have been addressed previously and included in the annual potential emissions represented for uncaptured emissions from marine loading.

The existing WC 509 platform complex includes a vent boom for natural gas blowdowns. Following the repurposing of the platform complex from natural gas service to crude oil service, the vent boom will be updated to include a high pressure flare (emissions previously addressed). Similarly, routine pigging of the vessel loading vapor return lines will be routed to a low pressure flare (emissions previously addressed).

The Project includes pig launchers and receivers on WC 509B for the crude oil pipeline. During maintenance activities requiring pigging, BMOP will utilize marine vessels for collection of the liquid pushed by the pigs. BMOP will follow the same Best Management Practices (BMP) as marine vessel loading and identify records as "maintenance." Because potential VOC and HAP emissions have been calculated based on continuous loading, emissions from loading losses as a result of pigging are already included in the potential emissions estimates above.

4. REGULATORY ANALYSIS

The Project is subject to certain federal and state air quality regulations. This section summarizes the air permitting requirements and key air quality regulations that would apply to the operation of the proposed DWP. Specifically, applicability to air permitting programs such as NSR, federal emissions standards such as NSPS and NESHAP, and applicable state air regulations are addressed.

4.1 Federal Permitting Programs

Federal permitting programs comprise requirements for construction of new major stationary sources or modification of existing major stationary sources (NSR) and for operation of major sources of air pollutants (Title V Air Operating Permit Program).

4.1.1 New Source Review

Federal NSR requires that construction of new emission sources or modifications to existing emission sources be evaluated when a significant project emissions increase and a significant net emissions increase result. Two distinct NSR permitting programs apply depending on whether the facility is located in an attainment or nonattainment area for a particular pollutant; nonattainment NSR permitting is required for facilities located in nonattainment areas, while PSD permitting is required for facilities located in attainment areas.

The DWP will be located approximately eighty-two (82) statute miles from the nearest point of the Louisiana coastline. The nearest Parish onshore is Cameron Parish, Louisiana. Cameron Parish is designated by the EPA as "attainment" or "unclassifiable" with NAAQS for all criteria pollutants.[32]

Therefore, the Project is not subject to offshore NNSR permitting requirements for any criteria pollutants. Under PSD permitting rules, the major source threshold is 250 tpy unless the facility is listed specifically in 40 CFR §52.21(b)(1)(i)(a) as having a lower 100 tpy threshold. The Project is not included on the list of operations subject to the more stringent 100 tpy threshold. As such, the Project will be subject to PSD permitting should emissions from the facility exceed the major source threshold of 250 tpy of any regulated NSR pollutant.

The following table presents the Project potential emissions in comparison to the major source thresholds.

[32] 40 CFR §81.319.

Table 4-1. PSD Major Stationary Source Determination

Regulated NSR Pollutant	Potential Emissions (tpy)	PSD Major Source Threshold (tpy)	Major Source?
NO_X	448.8	250	**YES**
CO	817.3	250	**YES**
VOC	2,473	250	**YES**
SO_2	14.66	250	No
PM-filterable	3.88	250	No
PM_{10}	16.00	250	No
$PM_{2.5}$	16.00	250	No
H_2S	1.04	250	No
H_2SO_4	0.05	250	No

Based on the potential operating emissions calculations for stationary sources, the Project is a major stationary source as potential emissions of a regulated NSR pollutant exceeds 250 tpy. As a new major stationary source, BMOP calculated emissions increases in accordance with 40 CFR §52.21(d).

> *A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the potential to emit… from each emissions unit following completion of the project and the baseline actual emissions… of these units before the project equals or exceeds the significant amount for that pollutant…*

The baseline emissions are considered zero for this analysis, and the project emissions increase is equal to the Project potential emissions. The following summarizes the project emissions increase in comparison to the significant emission rates (SER) for relevant regulated NSR pollutants (per 40 CFR §52.21(b)(23)).

Table 4-2. Project Emissions Increase Evaluation

Regulated NSR Pollutant	Potential Emissions (tpy)	Significant Emissions Rate[a] (tpy)	Above SER?
NO_X	448.8	40	**YES**
CO	817.3	100	**YES**
VOC	2,473	40	**YES**
SO_2	14.66	40	No
PM-filterable	3.88	25	No
PM_{10}	16.00	15	**YES**
$PM_{2.5}$	16.00	10	**YES**
H_2S	1.04	10	No
H_2SO_4	0.05	7	No
GHG (CO_2e)	494,797	75,000	**YES**

a. "Significant" for GHG is defined under 40 CFR §52.21(b)(49)(iii).

As identified in the table above, the Project exceeds the SER for NO_X, CO, VOC, PM_{10}, $PM_{2.5}$, and GHG. Accordingly, PSD review is required for NO_X, CO, VOC, PM_{10}, $PM_{2.5}$, and GHG.

Concurrent with this Title V permit application, BMOP is submitting a separate PSD air permit application encompassing the PSD requirements, including a Best Available Control Technology (BACT) analysis, air quality impacts analysis, and consideration of impacts to Class I areas.

4.1.2 Title V Air Operating Permit Program

Title V air operating permits are required for major stationary sources of air pollutants on the OCS, beyond state's seaward boundaries, as defined in 40 CFR §71. Based on potential emission calculations provided in Table 3-1, the Project will be a Title V major source since potential emissions exceed the Title V major source threshold for NO_X, CO, VOC and HAP. Therefore, BMOP is submitting this application for a Title V Air Operating Permit. The following Part 71 forms have been completed and included in Appendix B of this application:

- Initial Compliance Plan and Compliance Certification (Form I-Comp),
- Fee Calculation Worksheet (Form FEE), and
- Certification of Truth, Accuracy, and Completeness (Form CTAC).

4.1.3 State Permitting Program

The DWPA identifies that the law of the nearest adjacent coastal state will apply to a DWP, such as the proposed Project.[33] The nearest adjacent coastal state is Louisiana.

4.1.3.1 Louisiana Permitting Program

Louisiana's State Implementation Plan (SIP) provides the requirements for state permitting of construction or modification of emissions sources and operation of emission sources in Louisiana Administrative Code (LAC) 33.III.Chapter 5 – Permit Procedures, regulated by the LDEQ.

The LDEQ permitting provisions of this Chapter apply to the owner and operator of any source which emits or has the potential to emit any air contaminant.

Such sources include, but are not limited to:

- Any major source as defined LAC 33:III.502.A;
- Any nonmajor (area) source of hazardous air pollutants required to obtain an operating permit pursuant to regulations promulgated under Section 112 of the federal Clean Air Act; and
- Any nonmajor (minor) source that does not meet the exemptions specified in LAC 33:III.501.B and is thus required to obtain an air quality permit.

The Project will be subject to federal major source permitting under the Title V program, as discussed previously. As such, this application is submitted for review and a permitting determination by EPA Region 6, and will be subject to regulations under Louisiana's SIP, as applicable.

[33] 33 USC §1518(b).

4.2 Air Quality Regulations

The Project is potentially subject to federal and state regulations for air quality control. This section describes the applicability, criteria and principal requirements of federal, state, and local regulations that result in permit conditions for the offshore components of the Project.

4.2.1 Federal Regulations

This section outlines the federal applicability analysis. Both NSPS and NESHAP are evaluated.

4.2.1.1 New Source Performance Standards (NSPS)

NSPS require new, modified, or reconstructed sources to control emissions to the level achievable by the best demonstrated technology as specified in the applicable provisions. Moreover, any source subject to an NSPS is also subject to the general provisions of Subpart A, except as noted. Following is a discussion of potentially applicable subparts for the Project.

4.2.1.1.1 NSPS Subpart K – Volatile Organic Liquid Storage Vessels

NSPS Subpart K, *Standards of Performance for Storage Vessels for Petroleum* Liquids for which Construction, Reconstruction, or Modification Commenced After June 11, 1973 and Prior to May 19, 1978, regulates storage vessels for petroleum liquids with a capacity greater than 151,416 liters (40,000 gallons) which construction, reconstruction, or modification commenced after March 8, 1974, and prior to May 19, 1978. Subpart K also applies to storage vessels greater than 246,052 liters (65,000 gallons) that commenced construction or modification after June 11, 1973, and prior to May 19, 1978.

All of the Project's storage vessels will be constructed after May 19, 1978, and thus the Project is not subject to the requirements of Subpart K.

4.2.1.1.2 NSPS Subpart Ka – Volatile Organic Liquid Storage Vessels

NSPS Subpart Ka, *Standards of Performance for Storage Vessels for Petroleum Liquids* for Which Construction Reconstruction, or Modification Commenced After May 18, 1978 and Prior to July 23, 1984, regulates storage vessels for petroleum liquids with a capacity greater than 151,412 liters (40,000 gallons) which construction, reconstruction, or modification commenced after May 18, 1978, and prior to July 23, 1984.

All of the Project's storage vessels will be constructed after July 23, 1984, and thus the Project is not subject to the requirements of Subpart Ka

4.2.1.1.3 NSPS Subpart Kb – Volatile Organic Liquid Storage Vessels

NSPS Subpart Kb, *Standards of Performance for Volatile Organic Liquid Storage Vessels*, regulates storage vessels with a capacity greater than or equal to 75 cubic meters (m^3) (19,813 gallons) that are used to store volatile organic liquids for which construction, reconstruction, or modification commenced after July 23, 1984.

NSPS Subpart Kb has provisions in §60.110b(b) to exempt tanks based on size and the maximum TVP of the material stored. Specifically, NSPS Subpart Kb "does not apply to storage vessels with a capacity greater than or equal to 151 m^3 (39,890 gallons) storing a liquid with a maximum TVP less than 3.5 kilopascals (kPa) or with a capacity greater than or equal to 75 m^3 (19,813 gallons) but less than 151 m^3 (39,890 gallons) storing a liquid with a maximum TVP less than 15.0 kPa." Vessels permanently attached to

mobile vehicles such as trucks, railcars, barges, or ships are not subject to this subpart. In addition, process vessels do not meet the definition of a storage vessel per 40 CFR §60.111b.

The offshore Project includes the following storage vessels with a capacity greater than 19,813 gallons:

- One (1) 42,000 gallon crude oil surge tank located at the DWP platform.

However, the surge tank is considered a process vessel and is therefore not subject to NSPS Subpart Kb. EPA provided additional guidance that process tanks are exempt from Subpart Kb and that vessels used for pipeline surge control (not storage) are considered to be process tanks.[34] As such, the Project is not subject to the requirements of NSPS Subpart Kb.

4.2.1.1.4 NSPS Subpart IIII – Stationary Compression Ignition Internal Combustion Engines

NSPS Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines* applies to owners or operators of compression ignition (CI) internal combustion engines (ICE) that commenced construction, reconstruction or modification after July 11, 2005 and were manufactured after April 1, 2006 if not fire pump engines, and after July 1, 2006 if certified fire pump engines.

BMOP proposes the following CI ICE, located on the DWP platform, that are subject to the requirements of NSPS Subpart IIII:

- One (1) 336 kW (~450 hp) emergency diesel generator (40 CFR §60.4100(a)(2)(i));
- Two (2) 354 kW (~475 hp) non-emergency diesel crane engines (40 CFR §60.4100(a)(2)(i)); and
- Two (2) 485 kW (~650 hp) emergency diesel firewater pump engines (40 CFR §60.4100(a)(2)(ii)).

The one (1) 336 kW (~450 hp) emergency diesel generator will be subject to 40 CFR §60.4205(b), which states that owners or operators of 2007 model year and later emergency stationary CI ICE with a displacement of less than 30 liters per cylinder that are not fire pump engines must comply with emission standards for new CI engines in 40 CFR §60.4202. Per 40 CFR §60.4202(a)(2), 2007 model year or later emergency CI ICE <3,000 hp and displacement <10 L/cylinder that are not fire pump engines, must meet standards in 40 CFR § 1039, Appendix I and 40 CFR § 1039.105 (as applicable). Table 1 to Appendix I of 40 CFR §1039 limits emissions standards to the following for engines between 130kW to 560 kW:

- Non-methane hydrocarbons (NMHC) + NO_X – 4.0 g/kW-hr
- CO - 3.5 g/kW-hr
- PM - 0.2 g/kW-hr

The two (2) 354 kW (~475 hp) non-emergency diesel crane engines at WC 509 will be subject to 40 CFR §60.4204(b), which states that owners or operators of 2007 model year or later non-emergency stationary CI ICE with a displacement of less than 30 liters/cylinder must comply with emission standards for new CI engines in 40 CFR §60.4201. Per 40 CFR §60.4201(a), 2007 model year or later non-emergency CI ICE <3,000 hp and displacement <10 liters/cylinder must meet standards in 40 CFR §1039.101 (as applicable). Per Table 1 of 40 CFR §1039.101, for engines that are model year 2014 or later, between 130 kW and 560 kW, emission standards are as follows. Per 40 CFR §1039.101(e), exhaust emissions from the engines may not exceed the applicable NTE standards, which for the applicable pollutants (NO_X, NMHC, and PM) is 1.5

[34] 68 FR 59329-59330, October 15, 2003.

times the standard. The following emissions standards have included the appropriate NTE multiplier for the engines.

- PM - 0.03 g/kW-hr
- NO_X - 0.6 g/kW-hr
- NMHC (VOC) - 0.29 g/kW-hr
- CO - 3.5 g/kW-hr

The two (2) 485 kW (~650 hp) emergency diesel firewater pumps will be subject to 40 CFR §60.4205(c), which states that owners or operators of fire pump engines with a displacement of <30 liters/cylinder must comply with emission standards in Table 4 of NSPS Subpart IIII. Per Table 4, model year 2009 or later engines with a maximum engine power greater than or equal to 450 kW and less than or equal to 560 kW must meet the following emission standards:

- NMHC + NO_X - 4.0 g/kW-hr (3.0 g/bhp-hr)
- CO - 3.5 g/kW-hr (2.60 g/bhp-hr)
- PM - 0.2 g/kW-hr (0.15 g/bhp-hr)

Per 40 CFR §60.4209(a) and §60.4214(b), owners of emergency stationary CI ICE that do not meet the standards applicable to non-emergency engines must install a non-resettable hour meter prior to startup of the engine and keep records of the operation of the engine in emergency and non-emergency service. For all the CI ICEs, the owner must purchase an engine certified to the emission standards and install and configure the engine according to manufacturer's specifications, per 40 CFR §60.4211(c).

4.2.1.1.5 NSPS Subpart JJJJ – Stationary Spark Ignition Internal Combustion Engines

NSPS Subpart JJJJ, *Standards of Performance for Stationary Spark Ignition Internal Combustion Engines* applies to owners or operators of spark ignition ICE that commenced construction or were modified or reconstructed after June 12, 2006.

The two (2) proposed 1,736 kW (~2,328 hp) natural gas fired generators at the proposed DWP are considered spark ignition ICE and are subject to NSPS Subpart JJJJ per 40 CFR §60.4230(a)(4)(i). Per 40 CFR §60.4233(e), engines greater than 100 hp must comply with the emission standards in Table 1 of Subpart JJJJ.

Non-emergency lean burn engines greater than 1,350 hp manufactured after July 1, 2010, must meet the following emission standards, according to Table 1 of NSPS Subpart JJJJ:

- NO_X - 1.0 g/hp-hr or 1.36 g/kW-hr (82 ppmvd at 15% O_2)
- CO - 2.0 g/hp-hr or 2.72 g/kW-hr (270 ppmvd at 15% O_2)
- VOC - 0.7 g/hp-hr or 0.95 g/kW-hr (60 ppmvd at 15% O_2)

Per 40 CFR §60.4243(b), the owner must either purchase a certified engine, or if purchasing a non-certified engine, complete performance testing per 40 CFR §60.4244 to demonstrate compliance with emission limits. Initial performance testing is required within 180 days of startup (per Subpart A) and subsequent testing every 8,760 hours or 3 years, whichever comes first. Per 40 CFR §60.7(a)(3), initial notification is due within 15 days of startup.

4.2.1.1.6 NSPS Subpart OOOO – Crude Oil and Natural Gas Production, Transmission, and Distribution

NSPS Subpart OOOO, *Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution* establishes emission standards and compliance schedules for the control of VOC and SO_2 emissions from affected facilities that commence construction, modification, or reconstruction after August 23, 2011. Only onshore affected facilities are subject, which exclude all facilities located in the territorial seas or on the OCS.[35] Therefore, NSPS Subpart OOOO does not apply to the Project.

4.2.1.1.7 NSPS Subpart OOOOa – Crude Oil and Natural Gas Facilities

NSPS Subpart OOOOa establishes emission standards and compliance schedules for the control of GHG, VOC, and SO_2 emissions from affected facilities that commence construction, modification, or reconstruction after September 18, 2015. Similar to Subpart OOOO, above, affected facilities include only onshore operations. Therefore, NSPS Subpart OOOOa does not apply to the Project.

4.2.1.2 National Emission Standards for Hazardous Air Pollutants

NESHAP are emission standards for HAP and are applicable to major and area sources of HAP. A HAP major source is defined as having potential total HAP emissions in excess of 25 tpy and/or potential individual HAP emissions in excess of 10 tpy. An area source is a stationary source that is not a major source. Part 61 NESHAPs are chemical based NESHAPs, while Part 63 NESHAP allowable emission limits are established on the basis of a MACT determination for a particular source category. NESHAP apply to sources in specifically regulated industrial source categories (CAA Section 112(d)) or on a case-by-case basis (Section 112(g)) for facilities not regulated as a specific industrial source type. The Project is a major source of HAP, as potential individual and total HAP emissions are greater than 10 and 25 tpy, respectively.

Similar to NSPS, any source subject to a NESHAP is also subject to the general provisions of the respective NESHAP Subpart A, unless specifically excluded.

4.2.1.2.1 40 CFR §61 Subpart V - Equipment Leaks (Fugitive Emission Sources)

NESHAP Subpart V, *NESHAP for Equipment Leaks (Fugitive Emission Sources)* applies to the following sources that are intended to operate in volatile hazardous air pollutant (VHAP) service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by the subpart.

A 'VHAP' and 'in VHAP' service are respectively defined in 40 CFR §61.241 as:

> *VHAP means a substance regulated under this part for which a standard for equipment leaks of the substance has been proposed and promulgated. Benzene is a VHAP. Vinyl chloride is a VHAP.*
>
> *In VHAP service means that a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 10 percent by weight a volatile hazardous air pollutant (VHAP) as determined according to the provisions of §61.245(d). The provisions of §61.245(d) also specify how to determine that a piece of equipment is not in VHAP service.*

[35] Definition of "onshore" at 40 CFR §60.5430.

The crude oil to be handled and loaded at the DWP will contain benzene at less than 10% by weight. As such, the pipeline components regulated by this subpart will not operate "in VHAP service", as defined in 40 CFR §61.241. Therefore, Subpart V does not apply to the Project.

4.2.1.2.2 40 CFR §63 Subpart B – Control Technology Determinations for Major Sources in Accordance with Clean Air Act Sections 112(g) and 112(j)

Per 40 CFR §63.40(b), the use of CALM buoys in exposed waters to load crude oil into VLCCs (and other crude oil carriers) for export to the global market is potentially subject to Subpart B of Part 63.

> *The requirements of §63.40 through §63.44 of this subpart apply to any owner or operator who constructs or reconstructs a major source of hazardous air pollutants after the effective date of section 112(g)(2)(B) (as defined in §63.41) and the effective date of a title V permit program in the State or local jurisdiction in which the major source is (or would be) located unless the major source in question has been specifically regulated or exempted from regulation under a standard issued pursuant to section 112(d), section 112(h), or section 112(j) and incorporated in another subpart of part 63, or the owner or operator of such major source has received all necessary air quality permits for such construction or reconstruction project before the effective date of section 112(g)(2)(B).*

While BMOP previously prepared and submitted a case-by-case MACT application in accordance with Section 112(g) of the CAA to the EPA on September 28, 2020, the EPA stated their belief on September 13, 2022, that *NESHAP for Marine Tank Vessel Loading Operations* (40 CFR Part 63, Subpart Y) applies to the Project. In accordance with EPA's stated belief, the Project is not subject to Subpart B.

4.2.1.2.3 40 CFR §63 Subpart H – Equipment Leaks

NESHAP Subpart H, *NESHAP for Equipment Leaks* applies to pumps, compressors, agitators, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, instrumentation systems, and control devices or closed vent systems required by this subpart that are intended to operate in organic hazardous air pollutant service 300 hours or more during the calendar year within a source subject to the provisions of a specific subpart in 40 CFR §63 that references this subpart. No Part 63 subpart that applies to the Project references this Subpart H. Furthermore, "in organic HAP service" is defined in 40 CFR §63.161 as:

> *... a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 5 percent by weight of total organic HAP's as determined according to the provisions of §63.180(d) of this subpart. The provisions of §63.180(d) of this subpart also specify how to determine that a piece of equipment is not in organic HAP service.*

The Project will not operate pipeline components that are in organic HAP service; therefore, BMOP has determined that NESHAP Subpart H is not applicable to the Project.

4.2.1.2.4 40 CFR §63 Subpart Y – Marine Tank Loading Operations

NESHAP Subpart Y, *NESHAP for Marine Tank Loading Operations*, applies to marine tank loading operations located at major or area sources of HAP emissions. The Project will be a major source of HAP. In accordance with the September 13, 2022, letter, the EPA believes that the Project is subject to Subpart Y requirements for new major offshore loading terminals.

Following this interpretation, the Project would be considered a new major source offshore loading terminal as defined in 40 CFR § 63.561. 40 CFR Part 63, Subpart Y, is unique for NESHAP standards, as it includes

both MACT standards, as well as reasonably available control technology (RACT) standards. The applicable MACT standards are delineated below. The RACT standards of Subpart Y are not applicable to the Project.[36]

MACT Standards

The DWP is subject to the MACT standards in 40 CFR § 63.562(b) including:

- The operation of a vapor collection system to collect HAP vapors displaced from marine tank vessels during loading operations and to prevent HAP vapors collected at one loading berth from passing through another loading berth into the atmosphere [40 CFR § 63.562(b)(1)(i)];
- The limitation of marine tank vessel loading operations to vessels equipped with vapor collection equipment that is compatible with the terminal's vapor collection system [40 CFR § 63.562(b)(1)(ii)];
- The limitation of marine tank vessel loading operations to vessels which are vapor tight and connected to the vapor collection system [40 CFR § 63.562(b)(1)(iii)]; and
- For new major source offshore loading terminals, the reduction of HAP emissions from marine tank vessel loading operations by 95 weight percent [40 CFR § 63.562(b)(4)].
- Option to apply for a maintenance allowance for loading berths based on a percent of annual throughput of annual marine tank vessel loading operation time [40 CFR § 63.562(b)(6)]. Records of all maintenance performed on the air pollution control equipment shall be maintained.
  - BMOP is using this option to apply for a maintenance allowance for the loading berths at the DWP. BMOP's maintenance allowance is based on 629 hours, annually, of marine tank vessel loading operation time. The application for the maintenance allowance is included under separate cover with the PSD Volume I application.

Per 40 CFR §63.562(e), BMOP will be required to operate and maintain the source, including associated air pollution control equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. BMOP shall develop a written operation and maintenance plan that describes in detail a program of corrective action for varying air pollution control equipment and monitoring equipment in accordance with 63.562(e)(2), which will be used to demonstrate compliance with the MACT standard.

Compliance Requirements

BMOP is required to follow the vapor-tightness requirements for the marine vessel to be loaded, in accordance with 40 CFR § 63.563(a)(4):

- Provide a copy of the vapor-tightness pressure documentation described in § 63.567(i) for each marine tank vessel prior to loading [40 CFR § 63.563(a)(4)(i)];
- If no documentation of the vapor-tightness pressure test is available, then provide the leak test documentation described in § 63.567(i) prior to loading [40 CFR § 63.563(a)(4)(ii)];
  - The date of leak test must be within the preceding 12 months, and must have been conducted in accordance with § 63.565(c)(2).
  - If the marine tank vessel has failed its most recent vapor-tightness leak test at that terminal, the owner or operator of the non-vapor-tight marine tank vessel shall provide documentation that the

[36] *Existing* offshore loading terminals are explicitly exempted from both MACT and RACT standards (40 CFR § 63.560(d)(6)). For *new* offshore loading terminals, Subpart Y is explicit with an applicable MACT standard, but silent as to RACT (40 CFR § 63.562(b)(4)). This silence is intentional; it would be illogical for a more stringent RACT standard to be applicable without specific confirmatory language. Further, in the preamble to the Final Rule, EPA (1) "determined that offshore terminals loading 10 million barrels or more per year of gasoline or 200 million barrels or more of crude oil *should not* be required to control VOC or HAP emissions under section 183(f) RACT requirements" and (2) included a table of applicable standards, in which "new major source terminals located more than 0.8 kilometers (0.5 miles) offshore" need only meet Section 112 (i.e. MACT) standards. See 60 Fed. Reg. at 48,389, 48,393.

leaks detected during the previous vapor-tightness test have been repaired and documented with a successful vapor-tightness leak test described in § 63.565(c)(2) conducted during loading.
    - If the owner or operator of the marine tank vessel can document that repair is technically infeasible without cleaning and gas freeing or dry-docking the vessel, the owner or operator of the affected source may load the marine tank vessel.
- If no documentation of vapor tightness is available, the owner or operator of a marine tank vessel shall perform a leak test of the marine tank vessel during marine tank vessel loading operation using the procedures described in § 63.565(c)(2) [40 CFR § 63.563(a)(4)(iii)];
  - If no leak is detected during testing, the owner or operator of the marine vessel must complete the documentation in § 63.567(i).
  - If a leak is detected, the owner or operator of the marine tank vessel shall document the vapor-tightness failure for the marine tank vessel prior to departure of the vessel. The leaking component shall be repaired prior to the next marine tank vessel loading operation at a controlled terminal unless the repair is technically infeasible without cleaning and gas freeing or dry-docking the vessel. If the owner or operator of the vessel provides documentation that repair of such equipment is technically infeasible without cleaning and gas freeing or dry-docking the vessel, the equipment responsible for the leak will be excluded from future Method 21 tests until repairs are effected. A copy of this documentation shall be maintained by the owner or operator of the affected source. Repair of the equipment responsible for the leak shall occur the next time the vessel is cleaned and gas freed or dry-docked. For repairs that are technically feasible without dry-docking the vessel, the owner or operator of the affected source shall not load the vessel again unless the marine tank vessel owner or operator can document that the equipment responsible for the leak has been repaired.
- Ensure that a marine tank vessel is loaded with the product tank below atmospheric pressure (i.e., at negative gauge pressure). The pressure shall be measured between the facility's vapor connection and its manual isolation valve, and the measured pressure must be below atmospheric pressure. Following the date on which the initial performance test is completed, marine tank vessel loading operations for non-vapor-tight vessels must be performed below atmospheric pressure (i.e., at negative gauge pressure) in the product tank [40 CFR § 63.563(a)(4)(iii)];

Testing Requirements

- An initial performance test of the VCU control system is required within 180 days after the compliance date per 40 CFR § 63.563(b)(1). All testing shall be performed during the last 20 percent of loading of a tank or compartment per § 63.565(d)(2). The emissions testing intervals shall consist of each 5 minute period during the performance test in accordance with § 63.565(d). During initial performance testing, BMOP must determine the efficiency of and/or the outlet VOC concentration from the combustion device per § 63.563(b)(4).
  - BMOP shall establish as an operating parameter for the baseline VOC concentration using the procedures described in § 63.565(g). Following the initial performance test, the facility shall operate with a block average outlet VOC concentration no more than 20% above the baseline VOC concentration; or
  - BMOP shall establish an operating parameter for the baseline temperature using the procedures described in § 63.565(f) – either during the performance testing or from the manufacturer recommended minimum operating temperature for combustion devices. Following the initial performance test, the facility shall operate with the block average temperature as determined in § 63.564(e)(2) or (3) no more than 28°C (50°F) below the baseline temperature.
- BMOP shall inspect and monitor all ductwork and piping and connections to vapor collection systems and control devices once each calendar year using Method 21 [40 CFR § 63.563(c)(1)];

- If evidence of a potential leak is found, all ductwork, piping, and connections to the vapor collection system and control devices shall be inspected to the extent necessary to positively identify the potential leak and any potential leaks shall be monitored within 5 days by Method 21. Each detection of a leak shall be recorded, and the leak shall be tagged until repaired [40 CFR § 63.563(c)(2); and
- When a leak is detected, a first effort to repair the vapor collection system and control device shall be made within 15 days or prior to the next marine tank vessel loading operation, whichever is later [40 CFR § 63.563(c)(3)].

Test Methods and Procedures

- When testing a vessel for vapor tightness to comply with the marine vessel vapor-tightness requirements of § 63.563(a)(4)(i), the owner or operator shall use the methods delineated in § 63.565(c)(1) or (c)(2).
- For combustion devices, the average VOC concentration in the vent upstream and downstream shall be determined using Method 25 of appendix A of part 60 of this chapter for combustion devices, except flares. The average VOC concentration shall correspond to the volume measurement by taking into account the sampling system response time [40 CFR § 63.565(d)(4)]. Alternative test procedures may be submitted to EPA for review and approval 60 days prior to testing in accordance with § 63.565(m) and § 63.7(f).

Monitoring Requirements

BMOP will determine continuing compliance of the VCU control system by monitoring either of the following:

- A temperature monitor accurate to within ±10 °F or within 1 percent of the baseline temperature, whichever is less stringent, shall be installed, calibrated, and maintained per § 63.564(e)(4). The monitor shall be installed at the exhaust of each VCU, but not within the combustion zone, and shall measure and record the temperature every 15-minutes. The accuracy of the temperature monitor shall be verified once each calendar year with a reference temperature monitor. Monitored temperature shall be reduced to an average temperature each hour/cycle and a 3-hour/cycle block average every third hour/cycle per § 63.564(e)(2) or (3). Following the date that the initial performance test is completed, the 3-hour block average temperature shall be operated no more than 50 °F below the baseline temperature per § 63.563(b)(4)(ii).
- Alternatively, in accordance with § 63.564(e)(1), the VOC concentrations may be monitored at the exhaust point of the combustion device and recorded . For sources monitoring the outlet VOC concentration established during the performance test, a data acquisition system shall record a concentration every 15 minutes and shall compute and record an average concentration each cycle (same time period or cycle as the performance test) and a 3-cycle block average concentration every third cycle. The owner or operator will install, calibrate, operate, and maintain a CEMS consistent with the requirements of PS 8 to measure the VOC concentration. The daily calibration requirements are required only on days when marine tank vessel loading operations occur.

Recordkeeping and Reporting Requirements

- BMOP shall maintain a documentation file for each marine tank vessel loaded to reflect current test results as determined by the appropriate vapor tightness method per 40 CFR § 63.567(c);
- BMOP shall calculate an annual estimate of HAP emissions from marine tank vessel loading operations in accordance with 40 CFR § 63.565(l). BMOP shall maintain records of all measurements, calculations, and other documentation, and submit annual reports in accordance with 40 CFR § 63.567(j);
- BMOP shall maintain information for 5 years for each leak detected and repaired in accordance with 40 CFR § 63.567(k);

- BMOP is required to submit initial notification in accordance with 40 CFR § 63.9(b)(i);
- BMOP shall notify the Administrator in writing of the intention to conduct a performance test at least 60 calendar days before the performance test is scheduled to begin to allow the Administrator to review and approve the site-specific test plan required under § 63.7(c), if requested by the Administrator, and to have an observer present during the test [40 CFR § 63.9(e)];
- BMOP shall submit summary reports and excess emissions and monitoring system performance reports in accordance with 40 CFR § 63.567(e).

BMOP must comply with the general notification requirements per 40 CFR § 63.9, and recordkeeping and reporting requirements per 40 CFR § 63.10 in accordance with Table 1 to 40 CFR § 63.560.

4.2.1.2.5 40 CFR §63 Subpart HH – Oil and Natural Gas Production Facilities

NESHAP Subpart HH, *NESHAP from Oil and Natural Gas Production Facilities,* applies to owners and operators of affected sources at oil and natural gas production facilities at major or area sources of HAP emissions. The Project is not considered an oil and natural gas production facility per 40 CFR §63.760(a)(3), as it does not process, upgrade or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. Therefore, the Project is not subject to Subpart HH.

4.2.1.2.6 40 CFR §63 Subpart VV – Oil-Water Separators and Organic-Water Separators

NESHAP Subpart VV, *NESHAP for Oil-Water Separators and Organic-Water Separators,* applies to the control of air emissions from oil-water separators and organic-water separators for which another subpart of 40 CFR Parts 60, 61, or 63 references the use of this subpart for such air emission control. No Part 63 subpart that applies to the Project references Subpart VV. Therefore, BMOP has determined that NESHAP Subpart VV is not applicable to the Project.

4.2.1.2.7 40 CFR §63 Subpart HHH – Natural Gas Transmission and Storage Facilities

Per 40 CFR §63.1270(a) and (b), Subpart HHH applies to glycol dehydration units at major sources of HAP. The Project does not involve any glycol dehydration units; therefore, Subpart HHH is not applicable.

4.2.1.2.8 40 CFR §63 Subpart EEEE – Organic Liquids Distribution (Non-Gasoline)

NESHAP Subpart EEEE, *NESHAP for Organic Liquids Distribution (Non-Gasoline),* applies to organic liquids distribution (OLD) operations at, or part of, a major source of HAP emissions. Subpart EEEE includes standards for the following sources (40 CFR §63.2338):

- Storage tanks storing organic liquids
- Transfer racks at which organic liquids are loaded into, or unloaded out of, transport vehicles and/or containers
- All equipment leak components in organic liquid service that are associated with:
  - Storage tanks
  - Transfer racks
  - Pipelines between storage tanks and transfer racks
  - Transport vehicles and containers.

The proposed 1,000 barrel surge vessel is not a storage tank, as it is explicitly excluded from the definition of "storage tank" at 40 CFR §63.2406. The other storage tanks proposed do not store an organic liquid (excludes diesel, and fuels used for refueling). In addition, the project will not include a transfer rack, as

the delivery of crude is to marine vessels, not to a cargo tank or tank car. As such, the Project is not subject to requirements under Subpart EEEE.

4.2.1.2.9 40 CFR §63 Subpart ZZZZ – Stationary Reciprocating Internal Combustion Engines

NESHAP Subpart ZZZZ, *NESHAP for Stationary Reciprocating Internal Combustion Engines*, applies to reciprocating internal combustion engines (RICE) located at major or area sources of HAP emissions. A stationary RICE is any internal combustion engine which uses reciprocating motion to convert heat energy into mechanical work and which is not mobile. For engines located at a major source of HAP emissions, a stationary RICE is 'new' if the unit commenced construction or reconstruction on or after December 19, 2002 and if the engine has a site rating of more than 500 hp or on or after June 12, 2006 and if the engine has a site rating of less than or equal to 500 hp (40 CFR §63.6590(a)(2)(i) and (ii)). All the proposed engines associated with the WC 509 platform complex are considered 'new'.

Per 40 CFR §63.6590(c)(7), new CI stationary RICE with a site rating of less than or equal to 500 brake hp located at a major source of HAP emissions must meet the requirements of NESHAP ZZZZ by demonstrating compliance with NSPS Subpart JJJJ or IIII, respectively. This applies to the following RICE associated with the DWP project:

- Two (2) 354 kW (~475 hp) non-emergency diesel crane engines;
- One (1) 336kW (~450 hp) emergency diesel generator.

These engines have no further requirements under Subpart ZZZZ.

The two (2) proposed 1,736 kW (~2,328 hp) natural gas fired generators are four-stroke, lean burn spark ignition ICE and must comply with the emissions limitations in Table 2a and the operating limitations in Table 2b, per 40 CFR §63.6600(b), as provided below:

- Four-stroke lean burn engines must reduce CO emissions by 93% or more or limit the concentration of formaldehyde in the stationary RICE exhaust to 14 ppmvd or less at 15% O_2 [Table 2a];
- Maintain catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test [Table 2b]; and
  - Demonstrate initial compliance with CO reduction or formaldehyde limit in accordance with Table 5 [§63.6630(a)].
  - During the initial performance test, establish each operating limitation described above [§63.6630(b)].
  - Conduct initial performance testing per Table 4 of this subpart within 180 days of startup and in accordance with §63.7(a)(2) [§63.6610(a) and Table 4].
  - Submit a notification of compliance status containing the results of the initial compliance demonstration according to the requirements of §63.6645 [§63.6630(c)].
  - Conduct semi-annual performance tests for CO to demonstrate that the required CO percent reduction is achieved [§63.6615, §63.6640(a), Table 3 and Table 6].
- Maintain the temperature of your stationary RICE exhaust so that the catalyst inlet temperature is greater than or equal to 450°F and less than or equal to 1350°F [Table 2b].
  - Install, operate, and maintain a temperature continuous parameter monitoring system (CPMS) that meets the requirements of §63.6625(b) [§63.6625(b)].
  - Continuously collect and reduce data to 4-hour averages [§63.6635, §63.6640(a) and Table 6];
- Per 40 CFR §63.6605, at all times you must be in compliance with the emission limitations, operating limitations, and operate and maintain the engine, including associated air pollution control equipment

and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions;

- Per 40 CFR §63.6625(h), any new stationary engine must minimize engine idle time at startup and limit startup period to less than 30 minutes;
- Report each instance in which the engine did not meet the emission or operating limitations as deviations according to the requirements in §63.6650. If you change your catalyst, you must reestablish the values of the operating parameters measured during the initial performance test. When you reestablish the values of your operating parameters, you must also conduct a performance test to demonstrate that you are meeting the required emission limitation applicable to your stationary RICE. Deviations from the emission or operating limitations that occur during the first 200 hours of operation from engine startup (engine burn-in period) are not violations. [§63.6640(b) and (d)];
- Per 40 CFR §63.6650 and Table 7, submit compliance reports semi-annually according to the requirements of §63.6650(b)(1)-(5). These reports are due July 31 and January 31 for the periods of January 1 – June 30 and July 1 – December 31, respectively. These reports must contain the information included in §63.6650(c), (d), and (e), if applicable; and
- Maintain records as specified in §63.6655(a),(b)&(d) for 5 years [§63.6655 and §63.6660].

The two (2) 485 kW (~650 hp) emergency diesel firewater pump engines are subject only to an initial notification requirement of 40 CFR § 63.6645(f), in accordance with 40 CFR § 63.6590(b)(1)(i). No other requirements of Subpart ZZZZ or Subpart A apply.

4.2.1.3 Compliance Assurance Monitoring

Compliance Assurance Monitoring (CAM) applies to a pollutant-specific emissions unit at a major source that is required to obtain a Part 70 or 71 permit, if the unit is not exempt by the limitations or standards specified in 40 CFR §64.2(b), and satisfies the following criteria as detailed in 40 CFR §64.2(a):

(1) The unit is subject to an emission limitation or standard for the applicable regulated air pollutant (or a surrogate thereof);

(2) The unit uses a control device to achieve compliance with any such limitation or standard; and

(3) The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100 percent of the amount, in tons per year, required for a source to be classified as a major source.

CAM Plans are intended to provide an on-going and reasonable assurance of compliance with emission limits. For a subject unit using a control device whose post-controlled emissions exceed the major source threshold (referred to as large pollutant-specific emission units [PSEU] in the rule), a CAM plan is required to be submitted with the initial Title V air operating permit application. Additionally, these units must be subject to an emission limitation or standard and use control devices to achieve compliance with any such emission limit. For a subject unit whose post-control emissions are less than the major source threshold, a CAM plan does not have to be submitted until the first Title V air operating permit renewal application.

Marine loading will utilize the three (3) VCU as control devices for VOC. In accordance with the September 13, 2022, letter, the EPA believes the Project is subject to 40 CFR 63 Subpart Y, *NESHAP for Marine Loading Operations*. Per 40 CFR § 63.562(b)(4), HAP emissions from marine tank vessel loading operations must be reduced by 95 weight percent. Pre-control device potential emissions for marine loading would be above the major source threshold; therefore, the marine loading is potentially subject to CAM.

Per 40 CFR 64.2(b)(1)(i), a CAM Plan is not required if the emission limitation or standard was proposed after November 15, 1990, pursuant to Section 111 or 112 of the CAA. 40 CFR 63 Subpart Y was promulgated on September 19, 1995; therefore, a CAM Plan is not required for marine loading.

The two (2) proposed 1,736 kW (~2,328 hp) natural gas fired generators will utilize a control device to achieve compliance with an emission limit or standard.[37] The generators will be equipped with an oxidation catalyst to achieve compliance with the CO and VOC BACT requirements, as summarized in Section 5 from the analysis detailed in the PSD application (submitted under separate cover), such that CAM potentially applies to these units. However, the unit's potential pre-control device emissions of both CO and VOC are less than 100 tpy, each. Therefore, CAM does not apply to these units or this Project.

4.2.1.4 Risk Management Program

Requirements under 40 CFR §68, Chemical Accident Provisions, require submittal of a Risk Management Plan if the facility stores a regulated material above the applicable concentration and threshold values. Since BMOP will not store a regulated material above the applicable threshold limits, the Project is only subject to the General Duty Clause requirements and must review materials as purchased to verify if additional requirements must be met.

4.2.1.5 Greenhouse Gas Mandatory Reporting Rule

The EPA has promulgated monitoring, reporting, and recordkeeping rules for GHGs at 40 CFR Part 98. A facility is required to report its GHG emissions if its aggregate maximum rated heat input from all combustion sources is greater than 30 million British thermal units per hour (MMBtu/hr) and it emits more than 25,000 metric tpy of carbon dioxide equivalent (CO_2e) (40 CFR § 98.2(a)). The Project will monitor and report its GHG emissions under 40 CFR Part 98.

4.2.2 State Regulations

For Deepwater Port License Applications, EPA administers CAA requirements and reviews air permit applications using adjacent state's regulations. The nearest adjacent state to the DWP project's offshore location is Louisiana. Therefore, the LDEQ rules and regulations will apply to the offshore portion of the Project. Following is a discussion of potentially applicable LAC 33:III chapters for the Project.

4.2.2.1 Louisiana Air Quality Regulations

Following is a discussion of potentially applicable LAC 33:III chapters for the Project.

As discussed above, the Project is subject to Title V permitting under 40 CFR §71. For consistency with the applicable Louisiana SIP requirements, the LDEQ-required Title V Part 70 forms have been completed as part of the application.

The following LDEQ required application forms are provided in Appendix B of this application:

- The Application for Approval of Emissions of Air Pollutants from Part 70 Sources;
- Emissions Inventory Questionnaire (EIQ) Forms; and
- The Environmental Assessment Statement (EAS or "IT" Question Responses).

[37] Per 40 CFR §64.2(b)(i), CAM requirements do not apply to emission limits or standards proposed after November 15, 1990 pursuant to section 111 or 112 of the CAA.

4.2.2.1.1 LAC 33:III Chapter 11 – Control of Emissions of Smoke

This regulation prohibits impairment of visibility due to emissions of smoke and provides an opacity limit of 20 percent from combustion smoke except during periods of maintenance. Also provided are restrictions for outdoor burning. The opacity standards set forth in LAC 33:III.1101 do not apply to combustion units when combusting only natural gas and combustion units subject to a federal standard promulgated pursuant to section 111 or 112 of the Clean Air Act that limits average opacity to less than or equal to 20 percent, except for one six-minute period or less per hour.

The diesel combustion sources located at the DWP platform will be subject to this Chapter. However, all of the combustion sources combusting only natural gas will be exempt from this rule as they meet the criteria of LAC 33:III.1107.B.1.

4.2.2.1.2 LAC 33:III Chapter 13 – Emission Standards for Particulate Matter

This regulation prohibits impairment of visibility due to emissions of PM. According to LAC 33:III.1311.C, this regulation provides an opacity limit of 20 percent from emissions of PM. This regulation applies to all combustion sources of the offshore project.

4.2.2.1.3 LAC 33:III Chapter 15 – Emission Standards for Sulfur Dioxide

This regulation applies to new or existing sulfuric acid production units, sulfur recovery plants, and all other single point sources that emit or have the potential to emit 5 tpy or more of SO_2 into the atmosphere. Since no single point source for the Project emits or has the potential to emit 5 tpy or more of SO_2, this regulation does not apply.

4.2.2.1.4 LAC 33:III Chapter 21, Section 2103 – Storage of Volatile Organic Compounds

This regulation applies to storage tanks greater than 40,000 gallons which store VOC products with a maximum TVP of 1.5 psia or greater at storage conditions. The diesel storage tanks proposed as part of the Project are not subject to this regulation since the vapor pressure of diesel is less than 1.5 psia. The 42,000 gallon crude oil surge vessel located at the WC 509B platform is exempt from this regulation per LAC 33:III 2103.G.1, since the tank has a nominal storage capacity of less than 420,000 gallons and is not subject to NSPS.

4.2.2.1.5 LAC 33:III Chapter 21, Section 2108 – Marine Vapor Recovery

This regulation applies to any marine loading operation serving ships and/or barges loading crude oil, gasoline, or VOC with uncontrolled emissions of 25 tpy or more of VOC in the parishes of Ascension, East Baton Rouge, Iberville, Livingston, and West Baton Rouge, or 100 TPY or greater of VOC in any other parish of the State of Louisiana.

Since this is an offshore project and is not located onshore in any of the Louisiana parishes, BMOP has determined that this regulation is not applicable to the Project.

4.2.2.1.6 LAC 33:III Chapter 21, Section 2111 – Pumps and Compressors

Rotary pumps and compressors that handle VOCs having a TVP greater than or equal to 1.5 psia at handling conditions must be equipped with mechanical seals or other equivalent equipment or means as approved by the administrative authority. The WC 509 platform complex does not include crude oil pumps, nor natural gas compressors. The diesel equipment does not handle VOCs having a TVP greater than or equal to 1.5

psia. Only the condensate system for the existing natural gas lines, the surge vessel, and the sump system may have pumps that will be subject to this requirement.

4.2.2.1.7 LAC 33:III Chapter 21, Section 2113 – Housekeeping

This regulation defines the practices required to maintain the "best practical housekeeping and maintenance" for area VOC control. These practices include activities such as cleaning up spills, keeping containers closed, and properly storing waste. The Project is subject to this regulation.

4.2.2.1.8 LAC 33:III Chapter 21, Section 2121 – Fugitive Emission Control

This Section is applicable to each process unit at petroleum refineries, natural gas processing plants, synthetic organic chemical manufacturing industry facilities, methyl tertiary butyl ether manufacturing facilities, and polymer manufacturing facilities. The Project is not one of the listed facility types and is not subject to this regulation.

4.2.2.1.9 LAC 33:III Chapter 51 - Comprehensive Toxic Air Pollutant Emission Control Program

The provisions of the Comprehensive Toxic Air Pollutant (TAP) Program (LAC 33:III.Chapter 51) apply to owners and operators of any major source that emits, or has the potential to emit, 10 tpy or more of any individual TAP, or 25 tpy or more of any combination of TAPs, listed in Table 51.1 of LAC 33:III.5112. The Project will be subject to this chapter. An evaluation of the TAP program is included as part of the air quality impacts analysis in Volume 2 of the PSD application.

4.2.2.1.10 LAC 33:III Chapter 56 - Prevention of Air Pollution Emergency Episodes

This regulation is designed to prevent the buildup of excess concentrations of air contaminants during periods of high air pollution potential. The Project is subject to this regulation.

4.2.2.1.11 LAC 33:III Chapter 59 - Chemical Accident Prevention and Minimization of Consequences

This regulation does not apply to the Project since it does not produce, process, handle, or store any substance listed in LAC 33:III.5907 in greater than the threshold amounts.

5. PROPOSED CASE-BY-CASE REQUIREMENTS

BMOP is subject to the following requirements, with standards and compliance determined on a case-by-case basis:

- BACT, as detailed in the PSD application, submitted under separate cover.

This section presents a summary of the proposed applicable requirements to BMOP for BACT.

5.1 BACT Summary

For the PSD permit application, a BACT analysis was performed for NO_x, CO, VOC, $PM_{10}/PM_{2.5}$, and GHG, as the only pollutants with both a significant emissions increase and a significant net emissions increase from the proposed project. The BACT analysis follows the "top-down" approach suggested by EPA, as described in more detail in the PSD application submitted under separate cover.

The following emission units were considered in the BACT analysis, with a summary of proposed compliance requirements for each unit included in the following subsections.

- Marine Loading
- Combustion Sources
  - Large Natural Gas-Fired Engine-Driven Generators
  - Large Emergency Diesel-Fired Fire Pumps
  - Small Emergency Diesel-Fired Generators
  - Small Non-Emergency Diesel-Fired Crane Engines
- Fugitive Emissions
- Storage Vessels

5.2 VOC BACT

Table 5-1 below delineates a summary of the VOC BACT determination following a "top-down" approach, as suggested by EPA:

Table 5-1. Proposed VOC BACT Summary

Emission Source	Pollutant	Selected BACT	Emission / Operating Limit	Compliance Method
Marine Loading	VOC	VCU; Submerged fill;	99% Capture Efficiency; 95% Control Efficiency	MACT Subpart Y
Natural Gas-Fired Engine-Driven Generator	VOC	Oxidation catalysts	0.3 g/hp-hr	Performance Testing Per Table 2 of Subpart JJJJ
Emergency Diesel-Fired Engine-Driven Generator	VOC	Good combustion practices	4.0 g/kW-hr of NMHC + NO_X	Certified engine; Maintenance records
Diesel-Fired Crane Engines	VOC	Good combustion practices	0.29 g/kW-hr	Certified engine; Maintenance records
Emergency Diesel-Fired Engine-Driven Firewater Pumps	VOC	Good combustion practices	3.0 g/hp-hr of NMHC + NO_X	Certified engine; Maintenance records
Fugitive Emissions	VOC	Component design; Good operating practices	Leak monitoring program	Leak monitoring records
Storage Vessels	VOC	Submerged fill	Installation of conforming tanks	Fixed roof tanks with submerged fill pipes

5.2.1 Marine Loading Proposed Compliance Requirements

BMOP proposes the utilization of three (3) VCUs to achieve 95% VOC control efficiency in accordance with 40 CFR 63 Subpart Y. The BACT floor is equivalent to Subpart Y, and BMOP will be utilizing the maintenance allowance detailed in Subpart Y as part of the BACT.

BMOP shall be required to load using submerged fill only. BMOP shall be limited to loading only crude oil with a maximum TVP of 10.99 psia, at a maximum throughput of 80,000 bbl/hr.

Compliance assurance will be provided with the following monitoring and recordkeeping:

5.2.1.1 Monitoring

- Monitoring consistent with MACT Subpart Y.
- In addition, BMOP will monitor adherence to the terminal VOC BMP, which includes the use of submerged fill loading of crude carrying vessels and communication with the vessel being loaded.
  - BMOP will sample and analyze crude oil at the onshore Nederland Pump Station, at least once per year.
    - The sampling method will follow American Society for Testing and Methods (ASTM) D4057
    - The samples will be analyzed per D6377 to provide the true vapor pressure
  - BMOP will monitor the crude oil loading operations
    - Monitoring the crude oil loading rate with a flow meter.

- Compliance is demonstrated when:
  - The loading rate, averaged over each vessel's loading duration, is 80,000 bbl/hr or less.
  - The rolling 12-month total crude oil loaded is 605,000,000 bbls or less.
- Start and end loading time, duration per vessel monitored.
- Limited to 605,000,000 Bbl/yr, on a 12-month rolling total basis.

5.2.1.2 Recordkeeping

- Recordkeeping consistent with MACT Subpart Y.
- In addition, BMOP will maintain analytical results of each crude oil sample.
  - The TVP of each sample, in psia.
  - Comparison of TVP to the maximum allowed: 10.99 psia.
  - For each vessel loaded, BMOP will maintain the following records.
    - The vessel IMO registry number.
    - Confirmation that loading utilized submerged fill.
    - Confirmation of adherence to the VOC BMP.
    - The date and time loading of each vessel commences.
    - The date and time loading of each vessel completes.
    - The total crude oil loaded into each vessel (bbls).
    - The average hourly loading rate of crude oil (bbl/hr).

5.2.2 Non-Emergency Natural Gas-Fired Engine-Driven Generators Proposed Compliance Requirements

BMOP proposes a VOC BACT emission limit using the oxidation catalysts and GCP consistent with the NSPS Subpart JJJJ VOC emission limit of 0.3 g/hp-hr for the natural-gas fired generators. BMOP will demonstrate compliance with the VOC BACT consistent with the testing requirements of 40 CFR §60.4244 and Table 2 to Subpart JJJJ of Part 60.

At all times, BMOP will maintain the generators and oxidation catalysts in a manner consistent with safety and good air pollution control practices for minimizing emissions per 40 CFR §63.6605. BMOP will ensure proper maintenance of the catalyst such that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test. In addition, BMOP will maintain the temperature of the engine's exhaust so that the catalyst inlet temperature is greater than or equal to 450°F and less than or equal to 1,350°F, consistent with 40 CFR §63.6600(b) and Table 2b Subpart ZZZZ of Part 63. BMOP will install, operate, and maintain a temperature CPMS that meets the requirements of §63.6625(b) to continuously collect temperature data. In instances where the catalyst is changed, BMOP will reestablish the values of the operating parameters measured during the initial performance test and conduct a performance test to demonstrate that the engines are meeting the required emission limitations.

Because the oxidation catalyst is effective only at hot exhaust temperatures (>700°F), the use of Good Combustion Practices (GCP) and clean fuels will be the BACT work practice standards during startup to control VOC emissions.

5.2.3 Emergency Diesel-Fired Firewater Pumps Proposed Compliance Requirements

BMOP will operate the engine only when needed for intermittent purposes. Good combustion practices will allow the engine to meet the VOC emission limit in NSPS Subpart IIII of 3.0 g/bhp-hr for NMHC + NO_X.

Maintenance checks and readiness testing will be limited to 100 hours per year in accordance with 40 CFR §63.6640(f), not including operation during emergencies. BMOP will demonstrate compliance with the BACT standard by installing an engine that is certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of the engine and keep records of the operation of the engine in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.2.4 Emergency Diesel-Fired Engine-Driven Generators Proposed Compliance Requirements

BMOP will operate the engines only when needed for intermittent purposes. Good combustion practices will allow the engines to meet the VOC emission limit in NSPS Subpart IIII of 4.0 g/kW-hr (3.0 g/bhp-hr) for NMHC + NO_X. Maintenance checks and readiness testing will be limited to 100 hours per year in accordance with 40 CFR §63.6640(f), not including operation during emergencies. BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of each engine in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.2.5 Diesel-Fired Crane Engines Proposed Compliance Requirements

BMOP will operate the engines only when needed for intermittent purposes, at less than 4,380 hours per year, per engine. Good combustion practices will allow the engines to meet the VOC emission limit in NSPS Subpart IIII of 0.29 g/kW-hr. BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of the engines to confirm compliance with the operating restriction.

5.2.6 Fugitive Emissions Proposed Compliance Requirements

BMOP proposes the use of AVO monitoring as VOC BACT for fugitive emissions. BMOP will comply with the AVO monitoring as follows:

- During loading, BMOP will conduct AVO checks for leaks once per day during loading operations for the accessible crude oil components on the offshore platform.
  - As an alternative, BMOP may use an optical gas imaging instrument to identify leaks. If used as an alternative to AVO checks, the optical gas instrument must meet the requirements of 40 CFR §60.18(i)(1) and (2).
  - The date and time of each inspection shall be recorded.
- A repair will be attempted for identified leaks as soon as practicable. An initial repair attempt is required within five in-service days (for example, attempt to tighten a bolt or packing gland). If the initial repair attempt is not successful, additional repair attempts should be completed within fifteen in-service days.
  - The date(s) and time(s) of repairs conducted in response to an identified leak shall be recorded.
- Delay of repair of a leaking component is allowed for the following reasons: repair is technically infeasible without a DWP shutdown, a repair within fifteen days would result in emissions or impacts greater than fugitive emissions resulting from the delay of repair, or the unavailability of parts, resources, or repair conditions (i.e., weather) prevent repair within fifteen days. The component should be placed on a "Delay of Repair" list.

- The component identification and explanation of why the component cannot be repaired immediately shall be recorded. An estimated date for repairing the component must be included in the facility records.

► BMOP will develop a list of difficult-to-monitor and unsafe-to-monitor components.
  - A difficult-to-monitor component is one that cannot be inspected without elevating personnel more than two meters above a permanent support structure or requires a permit for confined space entry as defined in 29 CFR §1910.146, December 1, 1998.
  - An unsafe-to-monitor component is one that BMOP determines is unsafe to monitor because personnel would be exposed to immediate danger as a consequence of conducting the monitoring.

Leak protection is inherent to some of the equipment design at the proposed DWP. For example, the floating hoses used for loading crude oil are designed with elastomeric linings to prevent leaks. The double carcass design of the floating hoses themselves provide a second barrier for possible leaks.

5.2.7 Storage Vessels Proposed Compliance Requirements

BMOP proposes the use of storage vessels designed with submerged fill loading as VOC BACT. Compliance will be based on the installation of tanks equipped with submerged fill pipes.

5.3 CO BACT

Table 5-2 below delineates a summary of the CO BACT determination following a "top-down" approach, as suggested by EPA:

Table 5-2. Proposed CO BACT Summary

Emission Source	Pollutant	Selected BACT	Emission / Operating Limit	Compliance Method
Natural Gas-Fired Engine-Driven Generator	CO	Oxidation catalysts	0.23 g/hp-hr	Performance Testing Per Table 2 of Subpart JJJJ
Emergency Diesel-Fired Engine-Driven Generator	CO	Good combustion practices	3.5 g/kW-hr	Certified engine; Maintenance records
Diesel-Fired Crane Engines	CO	Good combustion practices	3.5 g/kW-hr	Certified engine; Maintenance records
Emergency Diesel-Fired Engine-Driven Firewater Pumps	CO	Good combustion practices	3.5 g/kW-hr	Certified engine; Maintenance records

5.3.1 Non-Emergency Natural Gas-Fired Engine-Driven Generators Proposed Compliance Requirements

Similar to the VOC BACT, BMOP proposes a CO BACT emission limit based on vendor specifications for the natural gas engines fitted with oxidation catalysts of 0.23 g/hp-hr. BMOP will demonstrate compliance with the CO BACT limit consistent with the testing requirements of 40 CFR §60.4244 and Table 2 to Subpart JJJJ of Part 60.

At all times, BMOP will maintain the generators and oxidation catalysts in a manner consistent with safety and good air pollution control practices for minimizing emissions per 40 CFR §63.6605. BMOP will ensure proper maintenance of the catalyst such that the pressure drop across the catalyst does not change by more than 2 inches of water at 100 percent load plus or minus 10 percent from the pressure drop across the catalyst that was measured during the initial performance test. In addition, BMOP will maintain the temperature of the engine's exhaust so that the catalyst inlet temperature is greater than or equal to 450°F and less than or equal to 1,350°F, consistent with 40 CFR §63.6600(b) and Table 2b Subpart ZZZZ of Part 63. BMOP will install, operate, and maintain a temperature CPMS that meets the requirements of §63.6625(b) to continuously collect temperature data. In instances where the catalyst is changed, BMOP will reestablish the values of the operating parameters measured during the initial performance test and conduct a performance test to demonstrate that the engines are meeting the required emission limitations.

Because the oxidation catalyst is effective only at hot exhaust temperatures (>700°F), the use of Good Combustion Practices (GCP) and clean fuels will be the BACT work practice standards during startup to control CO emissions.

5.3.2 Emergency Diesel-Fired Firewater Pumps Proposed Compliance Requirements

BMOP will operate the engines only when needed for intermittent purposes. Good combustion practices will allow the engine to meet the CO emission limit in NSPS Subpart IIII of 3.5 g/kW-hr (2.6 g/bhp-hr). BMOP will demonstrate compliance with the BACT standard by installing an engine that is certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of the engine and keep records of the operation of the engine in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.3.3 Emergency Diesel-Fired Engine-Driven Generators Proposed Compliance Requirements

BMOP will operate the engine only when needed for intermittent purposes. Good combustion practices will allow the engines to meet the CO emission limit in NSPS Subpart IIII of 3.5 g/kW-hr (2.6 g/bhp-hr). BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of each engine in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.3.4 Diesel-Fired Crane Engines Proposed Compliance Requirements

BMOP will operate the engines only when needed for intermittent purposes, at less than 4,380 hours per year, per engine. Good combustion practices will allow the engines to meet the CO emission limit in NSPS Subpart IIII of 3.5 g/kW-hr. BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of the engines to confirm compliance with the operating restriction.

5.4 NO_X BACT

Table 5-3 below delineates a summary of the NO_x BACT determination following a "top-down" approach, as suggested by EPA:

Table 5-3. Proposed NO_x BACT Summary

Emission Source	Pollutant	Selected BACT	Emission / Operating Limit	Compliance Method
Natural Gas-Fired Engine-Driven Generator	NO_x	Good combustion practices	0.5 g/hp-hr	Performance Testing Per Table 2 of Subpart JJJJ
Emergency Diesel-Fired Engine-Driven Generator	NO_x	Good combustion practices	4.0 g/kW-hr of NMHC + NO_X	Certified engine; Maintenance records
Diesel-Fired Crane Engines	NO_x	Good combustion practices	0.6 g/kW-hr	Certified engine; Maintenance records
Emergency Diesel-Fired Engine-Driven Firewater Pumps	NO_x	Good combustion practices	4.0 g/kW-hr (3.0 g/bhp-hr) of NMHC + NO_X	Certified engine; Maintenance records

5.4.1 Non-Emergency Natural Gas-Fired Engine-Driven Generators Proposed Compliance Requirements

BMOP proposes a NO_x BACT emission limit of 0.5 g/hp-hr for the natural-gas fired generators.[38] BMOP will operate the non-emergency generators with good combustion practices to meet this limit. BMOP will demonstrate compliance with the NO_x BACT limit consistent with the testing requirements of 40 CFR §60.4244 and Table 2 to Subpart JJJJ of Part 60.

5.4.2 Emergency Diesel-Fired Firewater Pumps Proposed Compliance Requirements

BMOP will operate the pumps only when needed for emergency purposes and intermittent maintenance and testing. Good combustion practices will allow the engine to meet the NO_x emission limit in NSPS Subpart IIII of 4.0 g/kW-hr (3.0 g/bhp-hr).[39] BMOP will demonstrate compliance with the BACT standard by installing an engine that is certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of the engine and keep records of the operation of the engine in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.4.3 Emergency Diesel-Fired Engine-Driven Generator Proposed Compliance Requirements

BMOP will operate the generator only when needed for emergency purposes and intermittent maintenance and testing. BMOP proposes the use of good combustion practices and selection of an engine that is certified to meet the NO_x emission limit in NSPS Subpart IIII of 4.0 g/kW-hr as BACT.[40] BMOP will demonstrate compliance with the BACT standard by installing an engine that is certified to meet the

[38] Lower than the standards of 40 CFR 60.4233(e) and Table 1 of 40 CFR 60 Subpart JJJJ.

[39] 40 CFR 60.4205(b) and Table 4 of 40 CFR 60 Subpart IIII. Conservatively, the emission limit for NMHC + NO_x is assumed as the NO_x BACT emission limit.

[40] 40 CFR 60.4202(a)(2) and Table 3 of Appendix I to 40 CFR 1039. Conservatively, the emission limit for NMHC + NO_x is assumed as the NO_x BACT emission limit.

emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of the engine and keep records of the operation of the engine in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.4.4 Diesel-Fired Crane Engines Proposed Compliance Requirements

BMOP will operate the engines only when needed for intermittent purposes, at less than 4,380 hours per year, per engine. Good combustion practices will allow the engines to meet the NO_x emission limit in NSPS Subpart IIII of 0.6 g/kW-hr.[41] BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of the engines to confirm compliance with the operating restriction.

5.5 $PM_{10}/PM_{2.5}$ BACT

Table 5-4 below delineates a summary of the $PM_{10}/PM_{2.5}$ BACT determination following a "top-down" approach, as suggested by EPA. The $PM_{10}/PM_{2.5}$ BACT emission/operating limits were conservatively assumed to be equal to PM emission/operating limits from the applicable subparts in 40 CFR Part 60.

Table 5-4. Proposed $PM_{10}/PM_{2.5}$ BACT Summary

Emission Source	Pollutant	Selected BACT	Emission / Operating Limit	Compliance Method
Natural Gas-Fired Engine-Driven Generator	$PM_{10}/PM_{2.5}$	Use of pipeline-quality natural gas, good combustion practices	Work Practice	Maintenance records
Emergency Diesel-Fired Engine-Driven Generator	$PM_{10}/PM_{2.5}$	Use of ultra-low sulfur diesel, good combustion practices	0.2 g/kW-hr	Certified engine; Maintenance records
Diesel-Fired Crane Engines	$PM_{10}/PM_{2.5}$	Use of ultra-low sulfur diesel, good combustion practices	0.03 g/kW-hr	Certified engine; Maintenance records
Emergency Diesel-Fired Engine-Driven Firewater Pumps	$PM_{10}/PM_{2.5}$	Use of ultra-low sulfur diesel, good combustion practices	0.2 g/kW-hr (0.15 g/bhp-hr)	Certified engine; Maintenance records

5.5.1 Non-Emergency Natural Gas-Fired Engine-Driven Generators Proposed Compliance Requirements

BMOP will operate the non-emergency generators using good combustion practices and combusting only natural gas as fuel to minimize $PM_{10}/PM_{2.5}$ emissions. BMOP will demonstrate compliance with the work practice standard by keeping records of maintenance performed on the engines.

[41] 40 CFR 60.4204(b) and Table 1 of 40 CFR 1039.101. Per 40 CFR 1039.101(e), NO_x emissions are multiplied by the appropriate NTE multiplier.

5.5.2 Emergency Diesel-Fired Firewater Pumps Proposed Compliance Requirements

BMOP will operate the pumps only when needed for emergency purposes and intermittent maintenance and testing. Good combustion practices and combustion of ultra-low sulfur diesel will allow the engine to meet the PM emission limit in NSPS Subpart IIII of 0.2 g/kW-hr (0.15 g/bhp-hr).[42] BMOP will demonstrate compliance with the BACT standard by installing an engine that is certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of the engine and keep records of the operation of the engine in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.5.3 Emergency Diesel-Fired Engine-Driven Generator Proposed Compliance Requirements

BMOP will operate the generator only when needed for emergency purposes and intermittent maintenance and testing. Good combustion practices and combustion of ultra-low sulfur diesel will allow the engine to meet the PM emission limit in NSPS Subpart IIII of 0.2 g/kW-hr.[43] BMOP will demonstrate compliance with the BACT standard by installing an engine that is certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of the engine and keep records of the operation of the engine in emergency and non-emergency service, in accordance with 40 CFR §60.4209(a) and 40 CFR §60.4214(b).

5.5.4 Diesel-Fired Crane Engines Proposed Compliance Requirements

Good combustion practices and combustion of ultra-low sulfur diesel will allow the engines to meet the PM emission limit in NSPS Subpart IIII of 0.03 g/kW-hr.[44] BMOP will demonstrate compliance with the BACT standard by installing engines that are certified to meet the emission limit, in accordance with 40 CFR §60.4211(c). BMOP will also install a non-resettable hour meter prior to startup of each engine and keep records of the operation of the engines to confirm compliance with the operating restriction.

5.6 GHG BACT

Table 5-5 below delineates a summary of the $PM_{10}/PM_{2.5}$ BACT determination following a "top-down" approach, as suggested by EPA:

[42] 40 CFR 60.4205(b) and Table 4 of 40 CFR 60 Subpart IIII.

[43] 40 CFR 60.4202(a)(2) and Table 3 of Appendix I to 40 CFR 1039. Conservatively, the emission limit for NMHC + NO_x is assumed as the NO_x BACT emission limit.

[44] 40 CFR 60.4204(b) and Table 1 of 40 CFR 1039.101. Per 40 CFR 1039.101(e), PM emissions are multiplied by the appropriate NTE multiplier.

Table 5-5. Proposed GHG BACT Summary

Emission Source	Pollutant	Selected BACT	Emission / Operating Limit	Compliance Method
Natural Gas-Fired Engine-Driven Generator	GHG	Use of natural gas, good combustion practices	12,871 tons CO_2e/yr, combined	Fuel consumption records
Emergency Diesel-Fired Engine-Driven Generator	GHG	Good combustion practices	Work Practice	Maintenance records
Diesel-Fired Crane Engines	GHG	Good combustion practices	Work Practice	Maintenance records
Emergency Diesel-Fired Engine-Driven Firewater Pumps	GHG	Good combustion practices	Work Practice	Maintenance records

Currently, only 40 CFR Part 60 Subparts TTTT and UUUUa establish emissions standards and standards of performance for the control of GHG from affected electric generating units (EGUs). Per 40 CFR 60.5508, an EGU includes an affected steam generating unit, integrated gasification combined cycle facility (IGCC), or stationary combustion turbines. The engines at the WC 509 Platform Complex are not considered EGUs and thus are not subject to any emissions standards of standards of performance for GHG.[45]

5.6.1 Non-Emergency Natural Gas-Fired Engine-Driven Generators Proposed Compliance Requirements

BMOP will operate the non-emergency generators using good combustion practices and combusting only natural gas as fuel to minimize GHG emissions. BMOP will demonstrate compliance with the annual BACT limit by monitoring fuel consumption and utilizing the emission factors of 40 CFR Part 98, Subpart C, Tables C-1 and C-2 and the current global warming potential from Subpart A to 40 CFR Part 98 (1 for CO_2, 25 for CH_4, and 298 for N_2O). These calculations will be performed on a monthly basis to ensure that the 12-month rolling total tons per year emission limit is not exceeded.

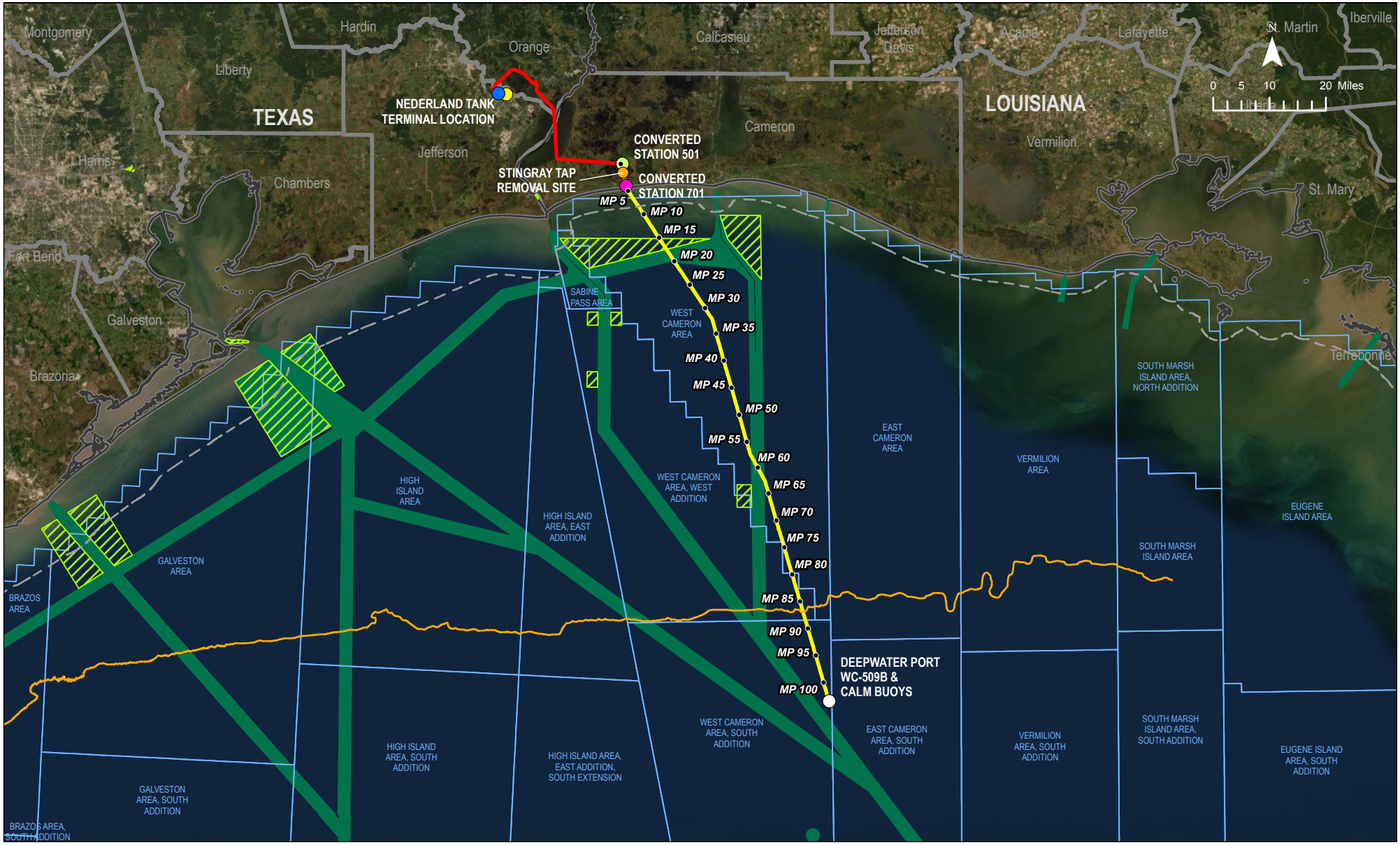
5.6.2 Diesel-Fired Engines Proposed Compliance Requirements

BMOP will operate all other diesel-fired engines at the WC 509 Platform Complex with good combustion practices to minimize GHG emissions. BMOP will demonstrate compliance with the work practice standard by keeping records of maintenance performed on the engines.

[45] 40 CFR 60.5580

APPENDIX A. SITE MAPS AND PLOT PLANS

BMOP PROJECT - APPENDIX A FIGURE 1 - PROJECT OVERVIEW MAP



LEGEND

- EXISTING OFFSHORE PIPELINE MILEPOSTS
- STINGRAY TAP REMOVAL SITE
- NEDERLAND TANK TERMINAL LOCATION
- NEDERLAND PUMP STATION
- CONVERTED STATION 701
- CONVERTED STATION 501
- DEEPWATER PORT WC-509B AND CALM BUOYS
- PIPELINE PORTION CONVERTED TO OIL SERVICE
- PROPOSED ONSHORE PIPELINE (NEW BUILD)
- DEPTH CONTOUR -108'
- STATE WATERS BOUNDARY
- SAFETY ANCHORAGES
- PROTRACTION AREA
- SHIPPING FAIRWAY
- COUNTY / PARISH
- STATE BOUNDARY

BLUE MARLIN OFFSHORE PORT PROJECT
PROJECT OVERVIEW MAP

COUNTY/PARISH:	VARIOUS	DRAWN BY:	JRA
STATE:	TX/LA	CHECKED BY:	CW

REV. NO.:	REVISION	DATE
A	ISSUE FOR REVIEW	2020/07/28

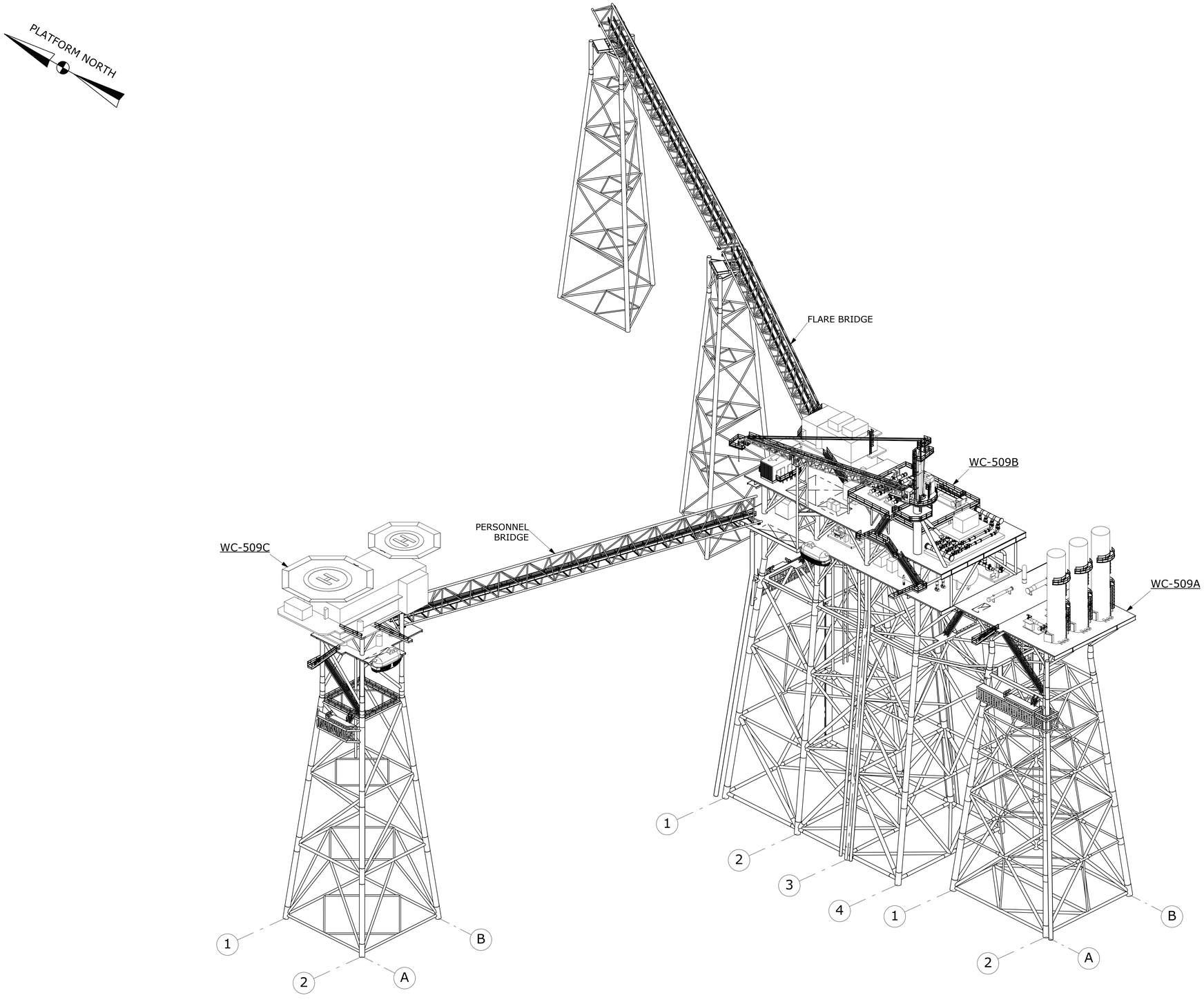
DATE:	2020/07/28	PROJECTION:	NAD 1983 UTM Zone 15N

PREPARED BY

EXP Energy Services Inc.
T: +1.850.385.5441
F: +1.850.385.5523
1800 WEST LOOP SOUTH, SUITE 850
HOUSTON, TX 77027, USA

BLUE MARLIN OFFSHORE PORT PROJECT
APPENDIX A FIGURE 1

DWG:	0802-01-005	SHEET:	1 OF 1



WOOD GROUP USA, INC.
TEXAS REGISTERED ENGINEERING FIRM F-2999
PROJECT NO: 245040

REFERENCE DRAWINGS

REV	DESCRIPTION	BY	DATE	CHK'D	APP'D
0A	ISSUED FOR REVIEW	BB	15DEC22	ET	HM
0	ISSUED FOR PERMIT	CRS	11AUG20	DD	HM
B	ISSUED FOR REVIEW	CRS	31JUL20	DD	HM
A	ISSUED FOR INTERDISCIPLINARY CHECK	CRS	17JUL20	DD	HM

FACILITY CODE OR ACCOUNT NO:
CONSTRUCTION YEAR:

	BY	DATE
DRAWN	BB	15DEC22
CHECK	ET	15DEC22
APPROVED	CN/HM	15DEC22

SCALE: N.T.S.

BLUE MARLIN OFFSHORE PORT LLC
GENERAL ARRANGEMENT
OVERALL PERSPECTIVE
WC-509 COMPLEX

AFE NO.

OLD DRAWING NO.

DRAWING NO. 245040-PIP-DWG-1000-010

REV. NO. 0A

APPENDIX B. LDEQ AND PART 71 FORMS

Application Forms

- Part 71 Forms
  - Certification of Truth, Accuracy, and Completeness (CTAC)
  - Fee Calculation Worksheet (FEE)
  - Initial Compliance Plan and Compliance Certification (I-COMP)
- LDEQ Forms
  - Application for Approval of Emissions of Air Pollutants from Part 70 Sources (AAE)

Part 71 Form

Certification of Truth, Accuracy, and Completeness (CTAC)

United States Environmental P Agency

OMB No. 2060-0336, Expires 11/30/2022

Federal Operating Permit Program (40 CFR Part 71)
CERTIFICATION OF TRUTH, ACCURACY, AND COMPLETENESS (CTAC)

This form must be completed, signed by the "Responsible Official" designated for the facility or emission unit, and sent with each submission of documents (i.e., application forms, updates to applications, reports, or any information required by a part 71 permit).

A. Responsible Official

Name: (Last) **Mcilwain** (First) **Gregory** (MI) ____

Title: **SVP – Operations**.

Street or P.O. Box **1300 Main Street**.

City **Houston** State **TX** ZIP **77002** - ____

Telephone **(713) 989-7120** Ext. ____ Facsimile (____) ____ - ____

B. Certification of Truth, Accuracy and Completeness (to be signed by the responsible official)

I certify under penalty of law, based on information and belief formed after reasonable inquiry, the statements and information contained in these documents are true, accurate and complete.

Name (signed) Greg McIlwain

Name (typed) **Gregory Mcilwain** Date: 4 / 14 / 23

INSTRUCTIONS FOR CTAC
CERTIFICATION OF TRUTH, ACURACY, and COMPLETENESS

Information Collection Burden Estimates

The public reporting and recordkeeping burden for this collection of information is estimated to average 247 hours per respondent per year. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed form to this address.

DETAILED INSTRUCTIONS

This form is for the responsible official to certify that submitted documents (i.e., permit applications, updates to application, reports, and any other information required to be submitted as a condition of a permit) are true, accurate, and complete.

This form should be completed and submitted with each set of documents sent to the permitting authority. It may be used at time of initial application, at each step of a phased application submittal, for application updates, as well as to accompany routine submittals required as a term or condition of a permit.

Section A - Title V permit applications must be signed by a responsible official. The definition of responsible official can be found at 40 CFR 70.2.

Section B - The responsible official must sign and date the certification of truth, accuracy and completeness. This should be done after all application forms are complete and the responsible official has reviewed the information. Normally this would be the last form completed before the package of forms is mailed to the permitting authority.

Part 71 Form

Fee Calculation Worksheet (FEE)

United States Environmental Protection Agency

OMB No. 2060-0336, Expires 11/30/2022

Federal Operating Permit Program (40 CFR Part 71)
FEE CALCULATION WORKSHEET (FEE)

Use this form initially, or thereafter on an annual basis, to calculate part 71 fees.

A. General Information

Type of fee (Check one): _X__Initial ___Annual

Deadline for submitting fee calculation worksheet ____/____/_____

For initial fees, emissions are based on (Check one):

_X_ Actual emissions for the preceding calendar year. (Required in most circumstances.)

___ Estimates of actual emissions for the current calendar year. (Required when operations commenced during the preceding calendar year.)

Date commenced operations ____/____/_____

___ Estimates of actual emissions for the preceding calendar year. (Optional after a part 71 permit was issued to replace a part 70 permit, but only if initial fee payment is due between January 1 and March 31; otherwise use actual emissions for the preceding calendar year.)

For annual fee payment, you are required to use actual emissions for the preceding calendar year.

B. Source Information: Complete this section only if you are paying fees but not applying for a permit.

Source or facility name _____

Mailing address: Street or P.O. Box _____

City_____ State_____ ZIP_____ - _____

Contact person_____ Title_____

Telephone (_____) _____ - _____ Ext_____ Part 71 permit no. _____

C. Certification of Truth, Accuracy and Completeness: Only needed if not submitting a separate form CTAC.

I certify under penalty of law, based on information and belief formed after reasonable inquiry, the statements and information contained in this submittal (form and attachments) are true, accurate and complete.

Name (signed) _____

Name (typed) _____ Date:____ /____ /_____

D. Annual Emissions Report for Fee Calculation Purposes -- Non-HAP

You may use this to report actual emissions (tons per year) of regulated pollutants (for fee calculation) on a calendar-year basis for both initial and annual fee calculation purposes. Section E is designed to report HAP emissions. Quantify all actual emissions, including fugitives, but do not include insignificant emissions and certain regulated air pollutants that are not counted for fee purposes, such as CO and GHGs (see instructions). Sum the emissions in each column to calculate subtotals. Subtotals should be reported to the nearest tenth (0.1) of a ton at the bottom of the page. If any subtotal exceeds 4,000 tons, enter 4,000 for that column.

This data is for **See Note 1 below** (year)

Emission Unit ID	NOx	VOC	SO2	PM10	Lead	Other
NGGEN1 (Natural Gas Generator #1)						
NGGEN2 (Natural Gas Generator #2)						
NGGEN CAP (Natural Gas Generators CAP)						
BCRANE1 (Platform B Crane #1 - Diesel)						
BCRANE2 (Platform B Crane #2 - Diesel)						
DGEN (Emergency Generator - Diesel)						
BFWP (Platform B Firewater Pump - Diesel)						
CFWP (Platform C Firewater Pump - Diesel)						
PDST (Primary Diesel Storage Tank)						
SRGT (Surge Tank)						
FUG (Facility Wide Fugitives)						
UNLD1 (Uncaptured Loading at Buoy #1)						
UNLD2 (Uncaptured Loading at Buoy #2)						
UNLD CAP (Uncaptured Loading CAP)						
VCU1 (VCU Stack 1)						
VCU2 (VCU Stack 2)						
VCU3 (VCU Stack 3)						
LPFL (Low Pressure Flare – Vapor Capture)						
HPFL (High Pressure Flare – Natural Gas)						
SUBTOTALS:						

Note 1- The project has not begun operations; therefore, there were no actual emissions.

E. Annual Emissions Report for Fee Calculation Purposes -- HAP

HAP Identification. Identify individual HAP emitted at the facility, identify the CAS number, and assign a unique identifier for use in the second table in this section. Whenever assigning identifier codes, use "HAP1" for the first, "HAP2" for the second, and so on.

Name of HAP	CAS No	Identifier
Acetaldehyde	75-07-0	HAP1
Acrolein	107-02-8	HAP2
Benzene	71-43-2	HAP3
Biphenyl	92-52-4	HAP4
Butadiene (1,3-)	106-99-0	HAP5
Carbon Tetrachloride	56-23-5	HAP6
Chlorobenzene	108-90-7	HAP7
Chloroform	67-66-3	HAP8
Cumene	98-82-8	HAP9
Cresols	1319-77-3	HAP10
Dichloropropene (1,3-)	542-75-6	HAP11
Ethylbenzene	100-41-4	HAP12
Ethylene Dibromide	106-93-4	HAP13
Formaldehyde	50-00-0	HAP14
Methanol	67-56-1	HAP15
Methylene Chloride	75-09-2	HAP16
n-Hexane	110-54-3	HAP17
Naphthalene	91-20-3	HAP18
PAH	-	HAP19
Phenol	108-95-2	HAP20
Styrene	100-42-5	HAP21
Toluene	108-88-3	HAP22
Tetrachloroethane (1,1,2,2-)	79-34-5	HAP23
Trichloroethane (1,1,2-)	79-00-5	HAP24
Trimethylpentane (2,2,4-)	540-84-1	HAP25
Vinyl Chloride	75-01-4	HAP26
Xylenes (mixed isomers)	1330-20-7	HAP27
Xylene (o-)	95-47-6	HAP28
Xylene (m-)	108-38-3	HAP29
Xylene (p-)	106-42-3	HAP30

HAP Emissions. Report the actual emissions of individual HAP identified above. Use the identifiers assigned in the table above. Include all emissions, including fugitives, and do not include insignificant emissions. Sum the emissions in each column to calculate subtotals. Report subtotals to the nearest tenth (0.1) of a ton at the bottom of the page. If any subtotal exceeds 4,000 tons, enter 4,000.

This data is for **See Note 1 below** (year)

Emissions Unit ID	Actual Emissions (Tons/Year)							
	HAP___	HAP___	HAP___	HAP___	HAP___	HAP___	HAP___	HAP___
SUBTOTALS:								

Note 1- The project has not begun operations; therefore, there were no actual emissions.

F. Fee Calculation Worksheet

This worksheet is used to calculate the total fee owed (including the emissions-based fee and the GHG fee adjustment) for both initial and annual fee payment purposes. Reconciliation is only for cases where you are paying the annual fee and you used any type of estimate of actual emissions when you calculated the initial fee. If you do not need to reconcile fees, complete line 1-5 (emissions summary) and then skip down to line 21 (emission calculation). See instructions for more detailed explanation.

EMISSIONS SUMMARY

1. Sum the subtotals from section D of this form (non-HAP) and enter the total, rounded to the nearest tenth (0.1) of a ton.	**0**
2. Sum the subtotals from section E of this form (HAP) and enter the total, rounded to the nearest tenth (0.1) of a ton.	**0**
3. Sum lines 1 and 2.	**0**
4. Enter the emissions that were counted twice. If none, enter "0."	**0**
5. Subtract line 4 from line 3, round to the nearest ton, and enter the result here. This is the **total emissions** that count for fees purposes.	**0**

RECONCILIATION
(WHEN INITIAL FEES WERE BASED ON ESTIMATES FOR THE "CURRENT" CALENDAR YEAR)

Only complete lines 6-10 if you are paying the first annual fee and initial fees were based on estimated actual emissions for the calendar year in which you paid initial fees; otherwise skip to line 11 or to line 21.

6. Enter the total estimated actual emissions for the year the initial fee was paid (previously reported on line 5 of the initial fee form).	**NA**
7. If line 5 is greater than line 6, subtract line 6 from line 5, and enter the result. Otherwise enter "0."	
8. If line 6 is greater than line 5, subtract line 5 from line 6, and enter the result. Otherwise enter "0."	
9. If line 7 is greater than 0, multiply line 7 by last year's fee rate ($/ton) and enter the result here. This is the underpayment. Go to line 21.	
10. If line 8 is greater than 0, multiply line 8 by last year's fee rate ($/ton) and enter the result here. This is the overpayment. Go to line 21.	

RECONCILIATION
(WHEN INITIAL FEES WERE BASED ON ESTIMATES FOR THE "PRECEDING" CALENDAR YEAR)

Only complete lines 11-20 if you are paying the first annual fee and initial fees were based on estimated actual emissions for the calendar year preceding initial fee payment; otherwise skip to line 21. If completing this section, you will also need to complete sections D and E to report actual emissions for the calendar year preceding initial fee payment.

11. Sum the actual emissions from section D (non-HAP) for the calendar year preceding initial fee payment and enter the result here.	**NA**
12. Sum the actual emissions from section E (HAP) for the calendar year preceding initial fee payment and enter the result here.	
13. Add lines 11 and 12 and enter the total here. These are total actual emissions for the calendar year preceding initial fee payment.	
14. Enter double counted emission from line 13 here. If none, enter "0."	
15. Subtract line 14 from line 13, round to the nearest ton, and enter the result here.	
16. Enter the total estimated actual emissions previously reported on line 5 of the initial fee form. These are estimated actual emissions for the calendar year preceding initial fee payment.	
17. If line 15 is greater than line 16, subtract line 16 from line 15, and enter the result here. Otherwise enter "0."	
18. If line 16 is greater than line 15, subtract line 15 from line 16, and enter the result here. Otherwise enter "0."	
19. If line 17 is greater than 0, multiply line 17 by last year's fee rate ($/ton) and enter the result here. This is the underpayment.	
20. If line 18 is greater than 0, multiply line 18 by last year's fee rate ($/ton) and enter the result on this line. This is the overpayment.	
EMISSION FEE CALCULATION	
21. Multiply line 5 (tons) by the current fee rate ($/ton) and enter the result here. This is the unadjusted emissions fee. Continue on to line 23.	**0**
GHG FEE ADJUSTMENT	
22. If you are submitting an initial permit application and this is the first time you are paying fees, enter $2,236, otherwise enter "0". [Note that any updates to the initial application are covered under this one-time charge.]	**0**
23. Enter the number of permit modifications (or related permit actions) you have submitted to the permitting authority since you last paid fees. If none, skip to line 25.	**0**
24. Multiply the number in line 23 by $365 and enter the result.	**0**

25. If you have submitted a permit renewal application since the last time you paid fees enter $520, otherwise enter “0”	**0**
26. Sum line 22, 24, and 25 and enter the result. This is the GHG fee adjustment	**0**
OTHER ADJUSTMENTS	
27. Add the total on line 21 and the total on line 26 and enter the result.	**0**
28. Enter any underpayment from line 9 or 19 here. Otherwise enter "0."	**0**
29. Enter any overpayment from line 10 or 20 here. Otherwise enter "0."	**0**
30. If line 28 is greater than "0," add it to line 27 and enter the result here. If line 29 is greater than "0," subtract this from line 27 and enter the result here. Otherwise enter the amount on line 27 here. This is the fee adjusted for over/underpayment**.**	**0**
31. Enter any credit for fee assessment error here. Otherwise, enter "0."	**0**
32. Subtract line 31 from line 30 and enter the result here. Stop here. This is the **TOTAL FEE (AFTER ADJUSTMENTS)** that you must remit to EPA.	**0**

INSTRUCTIONS FOR FEE
FEE CALCULATION WORKSHEET

Information Collection Burden Estimates

The public reporting and recordkeeping burden for this collection of information is estimated to average 247 hours per respondent per year. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed form to this address.

DETAILED INSTRUCTIONS

Use this form to initially or annually calculate fees. This form is for paying fees to EPA or a delegate agency (such as a State or tribe) under a part 71 operating permit program. The requirements for paying fees under part 71 programs, as well as the forms and instructions contained herein, are based on the requirements of 40 CFR 71.9

There may be cases, under a part 71 program, when you are not required to complete this form or pay the EPA fee rate (where the part 71 program has been delegated and EPA's fee has been suspended because EPA incurs no administrative costs). In such cases, the delegate agency will instruct you on how to calculate fees and how to pay them. If in doubt, contact your permitting authority.

General Rules for Fee Calculation under Part 71:

- Use the fee rate in effect at the time you pay the fee regardless of the time period that the emissions data represents. For example, if the annual fee for the current year is due July 1, you would use the fee rate in effect for the current year and the actual emissions for the previous calendar year.
- Do not prorate initial or annual fees. Pay full fees for the entire calendar year regardless of how many days you operated or were subject to the program during the previous or current year.
- Do not hesitate to contact the permitting authority if you have any doubt about how to calculate fees, especially if you have an unusual set of circumstances not addressed specifically by these forms or whenever the permit requirements appear to conflict with these forms (however, always assume the permit requirements take precedence in such cases).

Section A. General Information

The deadline for submitting the fee form and paying the fee for initial fee payment purposes for most sources is the same deadline as for submitting all other forms required for the initial permit application. Other deadlines apply for initial fee payment in certain limited circumstances:

- When a source is subject to part 71 because of an unresolved EPA objection to a part 70 permit, fees are not due with the part 71 application, but are due 3 months following the date of the issuance of the part 71 permit.
- When EPA withdraws approval of a part 70 program and implements a part 71 programs, fees are submitted according to a schedule based on the source's SIC code (within 6 to 9 months of the effective date of the part 71 program).

The deadline for submitting the fee form and paying the fee for annual fee payment purposes is the anniversary date of initial fee payment. This is required whether or not a permit has been issued. If you were required to pay initial fees between January 1 and March 31, the regulations allow for submittal of annual fees no later than April 1.

Whether you are paying initial or annual fees see the instructions for sections D and E for more information on which calendar-year emission data to use (preceding or current year) and how to quantify such emissions (actual emissions or estimates of actual emissions).

Section B. Source Information

Complete this section only if you are preparing this form for submittal at a different time than for the other portions of an initial application or for annual fee purposes.

Section C. Certification of Truth, Accuracy and Completeness

This form and any other document required by a permit must be signed by a responsible official certifying truth, accuracy and completeness of the information. If you are submitting a separate **CTAC** form, there is no need to complete this section of the form. If you complete this section, there is no need to submit form **CTAC** separately.

Section D. Annual Emissions Report for Fee Calculation Purposes – Non-HAP

Calculate actual emissions of regulated pollutants (for fee calculation), except for HAP, on a calendar-year basis for the facility in this section. Section E is provided to report actual emissions of HAP. Note the phrase “regulated pollutant (for fee calculation)” is any “regulated air pollutant” except carbon monoxide (CO), and pollutants regulated solely because they are: 1) subject to regulation under section 112(r) of the Act, or 2) a class I or II substance under title VI of the Act. **Note that GHG emissions are not counted for fee purposes.**

If more than one year of data is being submitted with the fee calculation worksheet, copy this page and complete a separate table for each year. If you are submitting an initial application, you may use emissions data already reported on form **EMISS**, provided this is the same data you would otherwise report in sections D and E of this form. If using **EMISS** in this manner, please note this on the fee calculation form. Also, sources must submit attachments to this form to show (at a minimum) examples of the calculations used to determine these values.

Show actual emissions for each listed air pollutant for each emission unit. Values should be reported to the nearest tenth (0.1) of a ton.

The column for "other" is for other regulated pollutants (for fee calculation) not already listed on the form. Write in the name of the pollutant in the proximity of the "other" column. If more than one such pollutant, show the pollutants, and the totals on an attachment.

Actual emissions must be calculated using actual operating hours, production rates, in-place control equipment, and types of materials processed, stored, or combusted over the preceding calendar year. Sources that have been issued title V permits are required to compute actual emissions using compliance methods required by the permits, such as monitoring or source testing data. If this is not possible, actual emissions should be determined using other federally recognized procedures.

For initial fee calculation purposes, most sources are required to use actual emissions for the preceding calendar year. However, there are certain exceptions where estimates of actual emissions are either required or allowed in place of actual emissions for the preceding calendar year (see table below):

Exception	Emission Data
When the source commenced operation during the preceding calendar year.	Estimates of actual emissions for the "current" calendar year are required
When EPA withdraws approval of a part 70 program and implements a part 71 program, and the source pays initial part 71 fees between January 1 and March	Either estimates of actual emissions for the "preceding" calendar year or actual emissions for the preceding calendar year may be used.
When a part 71 permit was issued following an unresolved objection to a part 70 permit, and the source is required to pay initial part 71 fees between January 1 and March 31.	Either estimates of actual emissions for the "preceding" calendar year or actual emissions for the preceding calendar year may be used.

For annual fee purposes, fee calculation should be based on actual emissions for the preceding calendar year in all cases.

In most cases you will only need to report one set of emission data using sections D and E of this form (the data that is the basis of the initial or annual fee being paid as explained above). This data is subsequently carried over to lines 1 and 2 of section F (Fee Calculation Worksheet) of the form.

However, there is one exception where you would be required to report two different sets of emissions data using sections D and E – when paying the first annual fee and reconciliation is required because the initial fee was based on estimated actual emissions for the "preceding" calendar year (the year preceding initial fee payment). In this case, the two data sets would be:

- actual emissions for the year initial fees paid (for annual fee purposes in lines 1-5 of section F of the form), and
- actual emissions for the year preceding initial fee payment (for reconciliation in lines 11-20 of the form)

Whenever reconciliation is required as part of annual fee payment, you will also need a copy of the fee forms you previously submitted with initial fee payment in order to obtain the value of estimated actual emissions.

Include all fugitive emissions in the calculation of actual emissions, including those that do not count for applicability. Do not include any insignificant emissions identified on form **IE**.

The subtotal line in section D of the form is provided at the bottom of each column to enter total emissions for each pollutant reported above. Each subtotal should be reported to the nearest tenth (0.1) of a ton. If any subtotal exceeds 4,000 tons, enter 4,000 tons for that column.

Any necessary adjustments for double counting of emissions will be performed later in section F.

Section E. Annual Emissions Report for Fee Calculation Purposes -- HAP

List the actual emissions of individual HAP from each emission unit. If you are initially applying for a permit, you may use the emissions of HAP reported on form **EMISS,** instead of completing this section of this form, provided these emissions are the same as you would otherwise report using this section of the form. If you are doing this, please note it on the form.

This section is composed of two tables. The first table is to identify individual HAP emitted at each emission unit. Assign a unique identifier for use in the second table. Please use "HAP1" for the first

one, "HAP2" for the second one, and so on. The second table is to calculate the actual emission of individual HAP at each emission unit. Use the identifiers assigned in the first table to label the column headers for the second table. You may round and report these emissions to the nearest tenth (0.1) of a ton. Sum the values in each column and enter the subtotals at the bottom of the table. If any subtotal exceeds 4,000 tons, enter 4,000 for that column.

See instructions for section D for more information on reporting emissions data.

Section F. Fee Calculation Worksheet

This worksheet is used to sum the total tons of actual emissions subject to fees, adjust for double counting of emissions, perform certain reconciliations for underpayment and overpayment of fees and adjust for fee assessment errors, if needed, and ultimately to determine the total fee to be paid.

A detailed explanation of Section F follows (separated into six parts):

Emissions Summary

The subtotals for each pollutant listed in Sections D and E (or from form **EMISS**) are added together to calculate the total emissions (in tons per year) for the facility.

The emissions that are reported here will vary for initial fee payment purposes, depending on the specific circumstances, but will always be actual emissions for the preceding calendar year for annual fee purposes. See the instructions for section D for more on the emissions data you should use in the part of the form.

The total emissions are adjusted for double counting and are rounded to the nearest ton. For example, double counting may occur where a pollutant is defined as HAP and VOC. If you adjust for double counting, attach an explanation for this.

Reconciliation (When Initial Emission Fees Were Based on Estimates for the Current Calendar Year)

This section is only used by sources paying their first annual fee when their initial fee was based on estimates of calendar-year emissions for the “current” year (the same year that initial fees were paid). This reconciliation is done by comparing the actual emissions for the “current” year provided in sections D and E of this submittal with the estimate of those emissions previously provided with initial fee payment. There may have been overpayment or underpayment of the initial fee. The fee you are paying now will be adjusted for this difference later.

Reconciliation (When Initial Emission Fees Were Based on Estimates for the Preceding Calendar Year)

This section is only used by sources paying their first annual fee when their initial fee was based on estimates of calendar-year emissions for the year preceding initial fee payment, provided the source was required to pay its initial fee between January 1 and March 31, and EPA issued the Part 71permit to replace a Part 70 permit. This reconciliation is done by comparing the actual emissions for the “preceding” year provided in sections D and E of this submittal with the estimate of those emissions provided with initial fee payment. There may have been overpayment or underpayment of the initial fee. The fee you are paying now will be adjusted for this difference later.

Emission Fee Calculation

Calculate the emission-based fee using the emissions from line 5 (tons) multiplied by the fee rate ($/ton) in effect at the time the fee is paid.

GHG Fee Adjustment

The part 71 rule was amended in 2015 to require the fees to be increased by a GHG fee adjustment. The GHG adjustment must be calculated by each source that is required to pay fees. The adjustment is based on the burden for the permitting authority to conduct certain GHG evaluations or reviews related to the source, rather than on emissions. Set fees are charged for certain activities that have occurred at the source since the last time fees were paid. For an initial application, the set fee is a one-time charge that includes the costs of processing application updates. The term “permit modification” refers to any significant and minor modifications, but not to administrative amendments. The number of permit modifications must be multiplied by the set fee for modifications to determine the total GHG adjustment for modifications. The set fee for a permit renewal also includes any permit modifications that may be processed at the same time as the renewal. Note that you may need to check with the permitting authority to determine if they are holding any permit modification requests you have submitted for processing with an upcoming permit renewal.

Other Adjustments

The purpose of this section is to adjust the emissions-based to determine the total fee (after adjustments) that is due to the EPA. The emissions fee determined on line 21 is adjusted by the GHG fee adjustment, any amounts of overpayment or underpayment related to a previous fee submittal, and to correct for any fee assessment errors.

Fee assessment errors occur when the permitting authority determines that the source has calculated the fee incorrectly. If this occurs, you will be notified of the error. Any overpayment will be credited against the next fee owed. In the case of underpayment, you will be billed for the corrected fee and you will have 30 days to remit the amount. If you think the assessed fee is in error, you may submit a written explanation of the alleged error, but you must pay the fee. The permitting authority will provide a determination in 90 days. If the assessment of underpayment is in error, your account will be credited.

Fee Payment

See form **FF** (the Fee Filing form) for instructions on how to make fee payment to the EPA.

Penalties and Interest

The permitting authority will bill sources for appropriate penalties and interest for late payment or excessive underpayment of fees. Interest will be assessed on payments received later than the due date. Penalties shall be assessed if payment is not paid within 30 days of the due date. For sources issued with issued permits, penalties and interest shall be assessed for excessive underpayment of the annual fee amount.

END

Part 71 Form

Initial Compliance Plan and Compliance Certification (I-COMP)

United States Environmental Protection Agency

OMB No. 2060-0336, Expires 11/30/2022

Federal Operating Permit Program (40 CFR Part 71)
INITIAL COMPLIANCE PLAN AND COMPLIANCE CERTIFICATION (I-COMP)

SECTION A - COMPLIANCE STATUS AND COMPLIANCE PLAN

Complete this section for each unique combination of applicable requirements and emissions units at the facility. List all compliance methods (monitoring, recordkeeping and reporting) you used to determine compliance with the applicable requirement described above. Indicate your compliance status at this time for this requirement and compliance methods and check "YES" or "NO" to the follow-up question.

Emission Unit ID(s): **NGGEN1 and NGGEN2**

Applicable Requirement (Describe and Cite):

(Excluding Formaldehyde) VOC Total <= 0.7 g/hp-hr (60 ppmdv at 15% O_2).	**40 CFR 60.4233(e)**
Carbon monoxide (CO) <= 2.0 g/hp-hr (270 ppmdv at 15% O_2).	**40 CFR 60.4233(e)**
Nitrogen oxides (NO_X) <= 1.0 g/hp-hr (82 ppmdv at 15% O_2).	**40 CFR 60.4233(e)**
Operate and maintain stationary SI ICE to achieve the emission standards as required in 40 CFR 60.4233 over the entire life of the engine.	**40 CFR 60.4234**
Purchase an engine certified according to procedures specified in this subpart, for the same model year and demonstrating compliance according to one of the methods specified in paragraph (a) of this section.	**40 CFR 60.4243(b)(1)**
Operate using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations. Keep records of such use. If propane is used for more than 100 hours per year and the engine is not certified to the emission standards when using propane, conduct a performance test to demonstrate compliance with the emission standards of 40 CFR 60.4233.	**40 CFR 60.4243(e)**

Compliance Methods for the Above (Description and Citation):

Keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions.	**40 CFR 60.4243(b)(2)(ii)**
Equipment/operational data recordkeeping by electronic or hard copy continuously. Keep records of the information in 40 CFR 60.4245(a)(1) through (a)(4).	**40 CFR 60.4245(a)**

Note: Final Requirements and Compliance Methods will be determined by PSD Permit.

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? __**X**__Yes ____No

Emission Unit ID(s): **BCRANE1 and BCRANE2**

Applicable Requirement (Description and Citation):

Shall comply with the emission standards for new CI engines in 40 CFR 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.	**40 CFR 60.4204(b)**
Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.	**40 CFR 60.4201(a)**
Shall operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4204 over the entire life of this engine.	**40 CFR 60.4206**
Beginning October 1, 2010, shall use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.	**40 CFR 60.4207(b)**
May not import or install stationary CI ICE that do not meet the applicable requirements in 40 CFR 60.4208.	**40 CFR 60.4208**
In addition to the requirements specified in 40 CFR 60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.	**40 CFR 60.4208(h)**
Owner or operator that must comply with the emission standards in this subpart shall do the following: - Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; - Change only those emission-related settings that are permitted by the manufacturer; and - Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply.	**40 CFR 60.4211(a)(1) through (a)(3)**
As stated in 40 CFR 60.4218, comply with the applicable general provisions listed in Table 8.	**40 CFR 60.4218; Table 8**
Shall comply by purchasing an engine certified to the emission standards in 40 CFR 60.4204(b) for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph 60.4211(g).	**40 CFR 60.4211(c)**
If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions.	**40 CFR 60.4211(g)**

Compliance Methods for the Above (Description and Citation):

If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in 40 CFR 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.	**40 CFR 60.4209(b)**
If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.	**40 CFR 60.4214(c)**
If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must keep a maintenance plan and records of conducted maintenance.	**40 CFR 60.4211(g)**
If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the manufacturer.	**40 CFR 60.4211(g)(2)**

Note: Final Requirements and Compliance Methods will be determined by PSD Permit.

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? __**X**__Yes _____No

Emission Unit ID(s): **DGEN, BFWP, and CFWP**

Applicable Requirement (Describe and Cite):

For the emergency generators: comply with the NMHC + NO_X, CO, and PM emission limitations set forth in Table 1 for the highest tier of the appropriate sized engine. All emergency generators are subject to the following standards: • CO limit of 3.5 g/kW-hr • PM limit of 0.20 g/kW-hr Engines greater than 560 kilowatts (kW) are subject to the following standard: • NMHC + NO_X limit of 6.4 g/kW-hr Engines with a rated power between 225-560 kW are subject to the following standard: • NMHC + NO_X limit of 4.0 g/kW-hr	**40 C.F.R. § 60.4202(a)(2),40 C.F.R. § 60.4202(b)(2), 40 C.F.R. § 89.112(a) Table 1**
For the emergency generators: exhaust opacity from CI nonroad engines (excluding single-cylinder engines, propulsion marine diesel engines, and constant speed engines) may not exceed: • 20% during the acceleration mode; • 15% during the lugging mode; and • 50% during the peaks in either the acceleration or lugging modes.	**40 C.F.R. § 60.4202(b)(2), 40 C.F.R. § 89.113**
For the fire pumps: comply with the NMHC + NO_X and PM emission limitations set forth in 40 C.F.R. Part 60 Subpart IIII Table 4 for 600-750 hp engines, 2009 model year and later.	**40 C.F.R. § 60.4205(c), 40 C.F.R. Part 60 Subpart IIII Table 4**

Compliance Methods for the Above (Description and Citation):

Operate and maintain stationary CI ICE that achieve the emission standards as required in 40 C.F.R. 60.4204 and 40 C.F.R. 60.4205 over the entire life of the engine.	**40 C.F.R. § 60.4206**
Use diesel fuel with a maximum sulfur content of 15 ppm. Use diesel fuel with a minimum cetane index of 40 or a maximum aromatic content of 35 volume %.	**40 C.F.R. § 60.4207(b), 40 C.F.R. § 80.510(b)**
If the emergency stationary CI internal combustion engine does not meet the standards applicable to non-emergency engines, install a non-resettable hour meter prior to startup of the engine.	**40 C.F.R. § 60.4209(a)**
Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions, change only those emission related settings that are permitted by the manufacturer, and meet the requirements of 40 C.F.R. Part 89, 94, and/or 1068, as they apply.	**40 C.F.R. § 60.4211(a)**
Purchase an engine certified to the emission standards in 40 C.F.R. § 60.4204(b), § 60.4205(b), or § 60.4205(c), as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 C.F.R. § 60.4211(g).	**40 C.F.R. § 60.4211(c)**

Operate according to the requirements in 40 C.F.R. 60.4211(f)(1), (f)(2)(i), and (f)(3). In order for the engine to be considered an emergency stationary ICE under 40 C.F.R. 60 Subpart IIII, any operation other than as described in 40 C.F.R. 60.4211(f)(1), (f)(2)(i), and (f)(3) is prohibited. If the engine is not operated according to these requirements, the engine will not be considered an emergency engine under 40 C.F.R. 60 Subpart IIII and must meet all requirements for non-emergency engines.	**40 C.F.R. § 60.4211(f)**
There is no time limit on the use of emergency stationary ICE in emergency situations.	**40 C.F.R. § 60.4211(f)(1)**
Operate for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, provided that the tests are recommended by the federal, state or local government; the manufacturer; the vendor; the regional transmission organization or equivalent balancing authority and transmission operator; or the insurance company associated with the engine. The administrator may be petitioned for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if records are maintained indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.	**40 C.F.R. § 60.4211(f)(2)(i)**
Operate for up to 50 hours per calendar year in non-emergency situations. Count the 50 hours of operation in non-emergency situations as part of the 100 hours per calendar year for maintenance and testing provided in 40 C.F.R. 60.4211(f)(2)(i). Do not use the 50 hours per calendar year for non-emergency situations for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity, except as provided in 40 C.F.R. 60.4211(f)(3)(i).	**40 C.F.R. § 60.4211(f)(3)**
Operating time recordkeeping by electronic or hard copy upon occurrence of event. If the emergency engine meets the standards applicable to emergency engines in the applicable model year, keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. Record the time of operation of the engine and the reason the engine was in operation during that time.	**40 C.F.R. § 60.4214(b)**

Note: Final Requirements and Compliance Methods will be determined by PSD Permit.

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? __**X**__Yes ____No

Emission Unit ID(s): **FUG**

Applicable Requirement (Describe and Cite)

Compliance Methods for the Above (Description and Citation):

Note: Final Requirements and Compliance Methods will be determined by PSD Permit.

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? __**X**__Yes ____No

Emission Unit ID(s): **UNLD1 and UNLD2**

Applicable Requirement (Describe and Cite)

Compliance Status:

Note: Final Requirements and Compliance Methods will be determined by PSD Permit.

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? __**X**__Yes ____No

Emission Unit ID(s): **VCU1, 2, and 3**

Applicable Requirement (Describe and Cite)

Operate a vapor collection system to collect HAP vapors displaced from marine tank vessels during loading operations and to prevent HAP vapors collected at one loading berth from passing through another loading berth into the atmosphere.	**40 CFR 63.562(b)(1)(i)**
Limit marine tank vessel loading operations to vessels equipped with vapor collection equipment that is compatible with the terminal's vapor collection system.	**40 CFR 63.562(b)(1)(ii)**
Limit marine tank vessel loading operations to vessels which are vapor tight and connected to the vapor collection system.	**40 CFR 63.562(b)(1)(iii)**
Reduce HAP emissions from marine tank vessel loading operations by 95 weight percent.	**40 CFR 63.562(b)(4)**
Follow vapor-tightness requirements for the marine vessels to be loaded.	**40 CFR 63.563(a)(4)**

Compliance Methods for the Above (Description and Citation):

Option to apply for a maintenance allowance for loading berths based on a percent of annual throughput of annual marine tank vessel loading operation time.	**40 CFR 63.562(b)(6)**
Operate and maintain the source, including associated air pollution control equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.	**40 CFR 63.562(e)**
Develop a written operation and maintenance plan that describes in detail a program of corrective action for varying air pollution control equipment and monitoring equipment used to comply with the MACT standard.	**40 CFR 63.562(e)**
Determine continuing compliance of the VCU control system by monitoring for outlet VOC concentration or temperature in accordance with 40 CFR § 63.564.	**40 CFR 63.564**
Records of all maintenance performed on the air pollution control equipment shall be maintained.	**40 CFR 63.562(b)(6)**
Perform an initial performance test of the VCU control system according to 40 CFR § 63.563(b)(1).	**40 CFR 63.563(b)(1)**

Note: Final Requirements and Compliance Methods will be determined by PSD Permit.

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? __**X**__Yes ____No

Emission Unit ID(s): **LPFL and HPFL**

Applicable Requirement (Describe and Cite)

Compliance Methods for the Above (Description and Citation):

Note: Final Requirements and Compliance Methods will be determined by PSD Permit.

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? __**X**__Yes ____No

B. SCHEDULE OF COMPLIANCE

Complete this section if you answered "NO" to any of the questions in section A. Also, complete this section if required to submit a schedule of compliance by an applicable requirement. Please attach copies of any judicial consent decrees or administrative orders for this requirement.

Unit(s)_____ Requirement_____

Reason for Noncompliance. Briefly explain reason for noncompliance at time of permit issuance or that future-effective requirement will not be met on a timely basis:

Narrative Description of how Source Compliance Will be Achieved. Briefly explain your plan for achieving compliance:

Schedule of Compliance. Provide a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance, including a date for final compliance.

Remedial Measure or Action	Date to be Achieved

C. SCHEDULE FOR SUBMISSION OF PROGRESS REPORTS

Only complete this section if you are required to submit one or more schedules of compliance in section B or if an applicable requirement requires submittal of a progress report. If a schedule of compliance is required, your progress report should start within 6 months of application submittal and subsequently, no less than every six months. One progress report may include information on multiple schedules of compliance.

Contents of Progress Report (describe):

First Report____/____/___ Frequency of Submittal_____

Contents of Progress Report (describe):

First Report____/____/___ Frequency of Submittal_____

D. SCHEDULE FOR SUBMISSION OF COMPLIANCE CERTIFICATIONS

This section must be completed once by every source. Indicate when you would prefer to submit compliance certifications during the term of your permit (at least once per year).

Frequency of submittal_____ Beginning____/____/____

E. COMPLIANCE WITH ENHANCED MONITORING & COMPLIANCE CERTIFICATION REQUIREMENTS

This section must be completed once by every source. To certify compliance with these, you must be able to certify compliance for every applicable requirement related to monitoring and compliance certification at every unit.

Enhanced Monitoring Requirements: ____ In Compliance ____ Not In Compliance

Compliance Certification Requirements: ____ In Compliance ____ Not In Compliance

INSTRUCTIONS FOR I-COMP

INITIAL COMPLIANCE PLAN AND COMPLIANCE CERTIFICATION

Section A (Compliance Status and Compliance Plan)

Description of Applicable Requirement: Complete Section A for each unique combination of applicable requirements (emission limitations, standards or other similar requirements of federal rules, SIP, TIP, FIP, or federally-enforceable permits) that apply to particular emissions units. You will likely have to complete this section numerous times to include all requirements at all emission units.

The emissions unit ID(s) should be the ones defined in section I of form GIS. If the requirement, including compliance method, applies in the same way to multiple emission units, you may list multiple units for a particular requirement.

The descriptions here should be detailed to the individual requirement level, rather than the standard level (if a MACT applies to you, describe each requirement of the MACT, rather than just a citation to the MACT as a whole). If the requirement imposes a particular numerical limit or range, include that in your description.

Citations to the requirements should unambiguously identify the requirement to the lowest level necessary.

Compliance Methods: List all compliance methods (monitoring, recordkeeping and reporting) you used to determine compliance with the applicable requirement described above. Such methods may be required by the applicable requirements or performed for other reasons. List all compliance methods required by applicable requirements, whether you used them to determine compliance or not.

To describe monitoring, indicate the monitoring device, the equipment, process, or pollutant monitored, averaging time, frequency, and a citation or cross-reference to the requirement. To describe recordkeeping, describe the records kept, the frequency of collection, and include a citation or cross-reference to the requirement. Please indicate whether monitoring data, results, or other records kept for compliance purposes may be kept on-site rather than reported. To describe reporting requirements, describe what is reported, when it is reported, and cite or cross-reference the requirement.

The citation or cross-reference here must unambiguously identify the requirement to the lowest level necessary.

Note that Compliance Assurance Monitoring (CAM) under part 64 is also an applicable requirement that may impose compliance methods for title V sources and require the submittal of a CAM plan with this application. Also note that periodic monitoring (which may be monitoring or recordkeeping designed to serve as monitoring) under part 71 may be required in certain limited circumstances: when there is no monitoring required, monitoring is required but there is no frequency specified, or only a one-time test is required. You may propose periodic monitoring in your application, but the permitting authority will make the final decision. If you wish to propose periodic monitoring, please do so in an attachment that clearly identifies the requirements, the units they apply to, and what you propose for periodic monitoring.

Compliance Status: For each requirement and associated compliance methods described above, indicate whether you are in compliance, not in compliance, or it is a future-effective requirement (only check one). This is with respect to your compliance status at the time of application submittal. You should consider all available information or knowledge that you have when evaluating your compliance status, including reference test methods and other compliance requirements that are required directly by a statute, regulation, or permit and “credible evidence” (e.g., non-reference test methods and other information “readily available” to you and already being utilized by you). For each compliance status indication, you must answer “YES” or “NO” as to your expectations for continuing (or future) compliance. If you answer “NO” to any of these questions, you will have to complete the schedule of compliance section (section B).

Section B (Schedule of Compliance)

Complete this section if you answered "NO" to any of the questions in section A. Regardless of how you answered the questions in section A, complete this section if required to have a schedule of compliance by an applicable requirement, or if a judicial consent decree or administrative order includes a schedule of compliance.

Identify the applicable requirement using the same information you used in section A. Provide a brief explanation of the reason for noncompliance (either now or in the future). [e.g., "do not have control device required as BACT."] Next, provide a brief description of what the schedule of compliance is trying to achieve. Then in the table provided, include a detailed schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance with the applicable requirement. This schedule shall resemble and be at least as stringent as that contained in any judicial consent decree or administrative order to which the source is subject. Any such schedule of compliance must be supplemental to, and not sanction noncompliance with, the applicable requirements on which it is based. For each remedial measure, provide the date by which the action will be completed. This schedule or one approved by the permitting authority will be included in the permit.

Lastly, attach a copy of any judicial consent decrees or administrative orders for which you are providing a schedule of compliance.

Section C (Schedule for Submission of Progress Reports)

If you must submit one or more schedules of compliance (specified in section B), or if an applicable requirement requires submittal of a progress report, complete this section. Progress reports describe your progress in meeting the milestone dates for the remedial measures required by the schedule of compliance. Progress reports must be submitted at least every 6 months, but specific applicable requirements may require them more frequently. One progress report may include information on one or more schedules of compliance. Describe the contents of the progress report, including the date that your facility will begin submitting them and the frequency they will be submitted.

Section D (Schedule for Submission of Compliance Certifications)

All applicants must complete this section. Compliance certifications must be submitted at least every year unless the applicable requirement or EPA requires them more frequently. Provide the date when the first compliance certification will be sent.

Section E (Compliance Status for Enhanced Monitoring and Compliance Certification)

All applicants must complete this section. The completion of this section does not satisfy the requirement for the responsible official to submit a certification of truth, accuracy, and completeness (instead, this is met by completing form CTAC and submitting it with the other forms you send to EPA).

To certify compliance with "Enhanced Monitoring," you must be in compliance at all emission units with CAM and "Periodic Monitoring" [required by 40 CFR 71.6(a)(3)(i)(B)], if they apply. "Compliance Certification Requirements" include requirements for compliance certification in title V applications and permits, and possibly through applicable requirements (e.g., certain MACT standards). If you have fully completed sections A - E of this form, you will be in compliance with the compliance certification requirement for applications. If you do not have a title V permit at this time, you can assume you are in compliance with the compliance certification requirements for permits and with periodic monitoring requirements. If you indicate you are "not in compliance" with either of these requirements, attach an explanation.

END

LDEQ Form

Application for Approval of Emissions of Air Pollutants from Part 70 Sources (AAE)

Department of Environmental Quality Office of Environmental Services Air Permits Division P.O. Box 4313 Baton Rouge, LA 70821-4313 (225) 219-3417	**LOUISIANA** **Application for Approval of Emissions of Air Pollutants from Part 70 Sources**	

PLEASE TYPE OR PRINT

1. Facility Information [LAC 33:III.517.D.1]

Facility Name or Process Unit Name (if any) Blue Marlin Offshore Port LLC – Deepwater Port (BMOP DWP)	☒ All Process Units ☐ Process Unit-specific Permit
Agency Interest Number (A.I. Number) 225545	**Currently Effective Permit Number(s)** N/A – New Facility
Company - Name of Owner Blue Marlin Offshore Port LLC	
Company - Name of Operator (if different from Owner) N/A	
Parent Company (if Company – Name of Owner given above is a division) Energy Transfer	
Federal Tax-ID	

☒ corporation, partnership, or sole proprietorship ☐ regulated utility ☐ municipal government

☐ state government ☐ federal government ☐ other, specify _____

2. Physical Location and Process Description [LAC 33:III.517.D.18, unless otherwise stated]

What does this facility produce? Add more rows as necessary.

The BMOP DWP will receive crude oil from existing facilities on the US mainland and load the crude oil into very large crude carriers (VLCCs) and other crude carriers for export to the global market.
Refer to section 1 of this application for detailed description.

What modifications/changes are proposed in this application? Add more rows as necessary.

Refer to section 1 of this application.

Nearest town (in the same parish as the facility): Cameron

Parish(es) where facility is located: Offshore Facility – West Cameron area, lease block 509

Distance To (mi):	115 Texas	315 Arkansas	240 Mississippi	300 Alabama
Latitude of Facility Front Gate:	28 Deg	26 Min	0.01 Sec	_____ Hundredths
Longitude of Facility Front Gate:	93 Deg	0 Min	15.23 Sec	_____ Hundredths
Distance from nearest Class I Area:	385	kilometers		

Add physical address and description of location of the facility below. If the facility has no address, provide driving directions. Add more rows as necessary.

The BMOP DWP will be located in federal waters within and adjacent to the Outer Continental Shelf (OCS) in West Cameron Lease Block (WC) 509 and 508 and East Cameron Block 263. The BMOP DWP will be approximately eighty-two (82) nautical miles off the coast of Cameron Parish, Louisiana, with an approximate water depth of 162 feet.

☒ Map attached (required per LAC 33:III.517.D.1)
☒ Description of processes and products attached (required per LAC 33:III.517.D.2)
☒ Introduction/Description of the proposed project attached (required per LAC 33:III.517.D.5)

3. Confidentiality [LAC 33.I.Chapter 5]

Are you requesting confidentiality for any information except air pollutant emission rates? ☒ Yes ☐ No

If "yes," list the sections for which confidentiality is requested below. Add rows as necessary. Confidentiality requests require a submittal that is separate from this application. Information for which confidentiality is requested should not be submitted with this application. Consult instructions.

Appendix D (BACT Supporting Documentation) of the Prevention of Significant Deterioration Air Construction Permit Application Volume 1

4. Type of Application [LAC 33:III.517.D]

Check all that apply.

☐ Renewal
Select one, if applicable: ☒ Entirely new facility ☐ Significant modification of existing facility (may also include reconciliations) [LAC 33:III.527] ☐ Minor modification of existing facility (may also include reconciliations) [LAC 33:III.525] ☐ Reconciliation only
NSR Analysis: ☒ Prevention of Significant Deterioration (PSD) ☐ Nonattainment New Source Review (NNSR)

Does this submittal update or replace an application currently under review? ☒ Yes ☐ No

If yes, provide date that the prior application was submitted: September 2020

Select one if this application is for an existing facility that does not have an air quality permit:

☐ Previously Grandfathered (LAC 33:III.501.B.6)
☐ Previously Exempted (e.g., Small Source Exemption; LAC 33:III.501.B.2.d)
☐ Previously Unpermitted

5. Fee Information [LAC 33:III.517.D.17]

Fee Parameter: If the fee code is based on an operational parameter (such as number of employees or capital cost), enter that parameter here. _____

Industrial Category: Enter the Standard Industrial Classification (SIC) and North American Industry Classification (NAICS) Codes that apply to the facility.

Primary SICC: 4612 **NAICS Code:** 486110

Secondary SICC(s): _____

Project Fee Calculation: Enter fee code, permit type, production capacity/throughput, and fee amount pursuant to LAC 33:III.Chapter 2. Add rows to this table as needed. Include with the application the amount in the Grand Total blank as the permit application fee.

FEE CODE	TYPE	EXISTING CAPACITY	INCREMENTAL CAPACITY INCREASE	*SURCHARGES*				
				MULTIPLIER	NSPS	PSD	AIR TOXICS	TOTAL AMOUNT
					☐	☐	☐	$
					☐	☐	☐	$
					GRAND TOTAL			$

Optional **Fee Explanation:** Use the space provided to give an explanation of the fee determination displayed above. Using this area will help to avoid confusion.

_____

_____

Electronic Fund Transfer (EFT): If paying the permit application fee using an Electronic Fund Transfer (EFT), please include the EFT Transaction Number, the Date that the EFT was made, and the total dollar amount submitted in the EFT. If not paying the permit application fee using EFT, leave blank.

EFT Transaction Number	Date of Submittal	Total Dollar Amount
_____	_____	$_____

6. Key Dates

Estimated date construction will commence: March 2024 *Estimated date operation will commence:* Oct. 2026

7. Pending Permit Applications – For Process Unit-Specific Permits Only [LAC 33:III.517.D.18]

List all other process units at this facility for which Part 70 permit applications have been submitted, but have not been acted upon by LDEQ as of the date of submittal of this application. If none, state "none" in the table. *****It is not necessary to update this table during the permit review process, unless requested by LDEQ.*****

Process Unit Name	Permit Number	Date Submitted
N/A		

8. LAC 33:I.1701 Requirements – Answer all below for new sources and permit renewals - ☒ Yes ☐ No

Does the company or owner have federal or state environmental permits identical to, or of a similar nature to, the permit for which you are applying in Louisiana or other states? (This requirement applies to all individuals, partnerships, corporations, or other entities who own a controlling interest of 50% or more in your company, or who participate in the environmental management of the facility for an entity applying for the permit or an ownership interest in the permit.)
☐ **Yes** ☒ **No**

If yes, list States: _____

Do you owe any outstanding fees or final penalties to the Department? ☐ **Yes** ☒ **No**
If yes, explain below. Add rows if necessary.

_____

_____

_____

Is your company a corporation or limited liability company? ☒ **Yes** ☐ **No**
If yes, attach a copy of your company's Certificate of Registration and/or Certificate of Good Standing from the Secretary of State. The appropriate certificate(s) should be attached to the end of this application as an appendix.

9. Permit Shield Request [LAC 33:III.517.E.7] - ☒ Yes ☐ No

See Section 1 of the Title V Air Operating Permit Application for the Permit Shield Request

If yes, check the appropriate boxes to indicate the type of permit shield being sought. Include the specific regulatory citation(s) for which the shield is being requested. Give an explanation of the circumstances that will justify the permit shield request. Attach additional pages if necessary. If additional pages are used, attach them directly behind this page and enter "See Attached Pages" into the Explanation field.

Type of Permit Shield request (check all that apply):

Non-applicability determination for:	Specific Citation(s)	Explanation
☐ 40 CFR 60		
☐ 40 CFR 61		
☐ 40 CFR 63		
☐ Prevention of Significant Deterioration		
☐ Nonattainment New Source Review		

Interpretation of monitoring, recordkeeping, and/or reporting requirements, and/or means of compliance for:	Specific Citation(s)	Explanation
☐ 40 CFR 60		
☐ 40 CFR 61		
☐ 40 CFR 63		
☐ Prevention of Significant Deterioration		
☐ Nonattainment New Source Review		
☐ State Implementation Plan (SIP) Regulation(s) referenced in 40 CFR 52 Subpart T		

10. Certification of Compliance With Applicable Requirements

Statement for Applicable Requirements for Which the Company and Facility Referenced In This Application Is In Compliance

Based on information and belief, formed after reasonable inquiry, the company and facility referenced in this application is in compliance with and will continue to comply with all applicable requirements pertaining to the sources covered by the permit application, as outlined in Tables 1 and 2 in the permit application. For requirements promulgated as of the date of this certification with compliance dates effective during the permit term, I further certify that the company and facility referenced in this application will comply with such requirements on a timely basis and will continue to comply with such requirements.

For corporations only: By signing this form, I certify that, in accordance with the definition of Responsible Official found in LAC 33:III.502, **(1)** I am a president, secretary, treasurer, or vice-president in charge of a principal business function, or other person who performs similar policy or decision-making functions; or **(2)** I am a duly authorized representative of such person; am responsible for the overall operation of one or more manufacturing, production, or operating facilities addressed in this permit application; and either the facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or the delegation of authority has been approved by LDEQ prior to this certification.*

CERTIFICATION: I certify, under provisions in Louisiana and United States law which provide criminal penalties for false statements, that based on information and belief formed after reasonable inquiry, the statements and information contained in this Application for Approval of Emissions of Air Pollutants from Part 70 Sources, including all attachments thereto and the compliance statement above, are true, accurate, and complete.

a. Responsible Official		
Name Gregory Mcilwain		
Title SVP - Operations		
Company Energy Transfer		
Suite, mail drop, or division		
Street or P.O. Box 1300 Main Street		
City Houston	State TX	Zip 77002
Business phone (713) 989-7120		
Email Address Gregory.mcilwain@energytransfer.com		

Signature of responsible official (See 40 CFR 70.2):
Date: 4/14/23

*Approval of a delegation of authority can be requested by completing a Duly Authorized Representative Designation Form (Form_7218) available on LDEQ's website at http://deq.louisiana.gov/page/air-permit-applications

CERTIFICATION: I certify that the engineering calculations, drawings, and design are true and accurate to the best of my knowledge.

b. Professional Engineer		
Name Mallorie A. Lefante, P.E.		
Title Senior Consultant		
Company Trinity Consultants Inc.		
Suite, mail drop, or division Suite 1030		
Street or P.O. Box One Galleria Blvd.		
City Metairie	State LA	Zip 70001
Business phone (504) 559-7704		
Email Address mlefante@trinityconsultants.com		

Signature of Professional Engineer:
Date: 4/14/2023
Louisiana Registration No.

STATE OF LOUISIANA
MALLORIE A. LEFANTE
License No. 40331
PROFESSIONAL ENGINEER IN ENVIRONMENTAL ENGINEERING

11. Personnel [LAC 33:III.517.D.1]

a. Manager of Facility who is located at plant site*		
Name	☐Primary contact	
Title		
Company		
Suite, mail drop, or division		
Street or P.O. Box		
City	**State**	**Zip**
Business phone		
Email address		

*No "on-site" person will be present on the offshore platform.

b. On-site contact regarding air pollution control*		
Name	☐Primary contact	
Title		
Company		
Suite, mail drop, or division		
Street or P.O. Box		
City	**State**	**Zip**
Business phone		
Email address		

*No "on-site" person will be present on the offshore platform.

c. Person to contact with written correspondence		
Name Lisa M. Garcia, P.E.	☒Primary contact	
Title Sr. Manager - Engineering		
Company Energy Transfer		
Suite, mail drop, or division		
Street or P.O. Box 1300 Main Street		
City Houston	**State** TX	**Zip** 77002
Business phone (713) 989-7762		
Email address Lisa.Garcia@energytransfer.com		

d. Person who prepared this report		
Name Michael Ballenger, P.E.	☐Primary contact	
Title Manager of Consulting Services		
Company Trinity Consultants Inc.		
Suite, mail drop, or division B		
Street or P.O. Box 919 Lake Baldwin Ln		
City Orlando	**State** FL	**Zip** 32814
Business phone (407) 982-2891 Ext.1901		
Email address mballenger@trinityconsultants.com		

e. Person to contact about Annual Maintenance Fees	☐ a ☐ b ☒ c ☐ d ☐ other (specify below)		
Name	☐Primary contact	**Suite, mail drop, or division**	
Title		**Street or P.O. Box**	
Company		**City**	**State** / **Zip**
Business Phone		**Email Address**	

12. Proposed Project Emissions [LAC 33:III.517.D.3]

List the total emissions following the proposed project for this facility or process unit (for process unit-specific permits). Speciate all criteria pollutants, TAP, and HAP for the proposed project.

Pollutant	Proposed Emission Rate (tons/yr)
Particulate matter (PM_{10})	16.00
Particulate matter ($PM_{2.5}$)	16.00
Nitrogen oxides	448.79
Carbon monoxide	817.25
Sulfur dioxide	14.66
Total VOC	2,473
CO_2e	494,797
Sulfuric Acid	0.05
Hydrogen sulfide	1.04
Total HAPs*	143.90

* Please see Appendix B for detailed list of HAPs and TAPs.

13. History of Permitted Emissions [LAC 33:III.517.D.18]

List each of the following in chronological order:

- The Permit Number and Date Action Issued for each air quality permit that has been issued to this facility or process unit (for process unit-specific permits) within the last ten (10) years.
- All small source exemptions, authorizations to construct, administrative amendments, case-by-case insignificant activities, and changes of tank service that have been approved since the currently effective Title V Operating Permit or State Operating Permit was issued to this facility or process unit (for process unit-specific permits). It is not necessary to list any such activities issued prior to the issuance of the currently effective Title V Operating Permit or State Operating Permit, if one exists.

Permit Number	Date Action Issued
N/A – New Facility	

14.a. Enforcement Actions [LAC 33:III.517.D.18] - ☐ Yes ☒ No

If yes, list all federal and state air quality enforcement actions, settlement agreements, and consent decrees received for this facility and/or process unit (for process unit-specific permits) since the issuance of the currently effective Title V Operating Permit or State Operating Permit. For each action, list the type of action (or its tracking number), the regulatory authority or authorities that issued the action, and the date that the action was issued. Summarize the conditions imposed by the enforcement action, settlement agreement, and consent decree in Section 22, Table 2. It is not necessary to submit a copy of the referenced action. Add rows to table as necessary.

Type of Action or Tracking Number	Issuing Authority	Date Action Issued	Summary of Conditions Included?
			☐ Yes ☐ No
			☐ Yes ☐ No

14.b. Schedule for Compliance [LAC 33:III.517.E.4] ☐ Yes ☒ No

If the facility or process unit for which application is being made is not in full compliance with all applicable regulations, give a description of how compliance will be achieved, including a schedule for compliance below. Add rows as necessary. See instructions.

15. Letters of Approval for Alternate Methods of Compliance - ☐ Yes ☒ No

If yes, list all correspondence with LDEQ, EPA, or other regulatory bodies that provides for or supports a request for alternate methods of compliance with any applicable regulations for this facility or process unit (for process unit-specific permits). List the date of issuance of the letter and the regulation referenced by the letter. **Attach as an appendix a copy of all documents referenced in this table.** Letters that are not included may not be incorporated into a final permit. Add rows to table as necessary.

Date Letter Issued	Issuing Authority	Referenced Regulation(s)	Copy of Letter Attached?
			☐ Yes ☐ No
			☐ Yes ☐ No
			☐ Yes ☐ No
			☐ Yes ☐ No

16. Initial Notifications and Performance Tests [LAC 33:III.517.D.18] - ☐ Yes ☒ No

If yes, list any initial notifications that have been submitted or one-time performance tests that have been performed for this facility or process unit (for process unit-specific permits) since the issuance of the currently effective Title V Operating Permit or State Operating Permit in order to satisfy regulatory requirements. Any initial notification or one-time performance test requirements that have not been satisfied should be listed in Section 22, Table 2 of this application. Any notifications or performance tests that recur periodically should also be properly noted in Section 22, Table 2 of this application. Add rows to table as necessary.

Initial Notification or One-time Performance Test?	Regulatory Citation Satisfied	Applicable Source(s)	Date Completed/Approved

17. Existing Prevention of Significant Deterioration or Nonattainment New Source Review Limitations [LAC 33:III.517.D.18]

Do one or more emissions sources represented in this permit application currently operate under one or more NSR permits?
☐ **Yes** ☒ **No**

If "yes," summarize the limitations from such permit(s) in the following table. Add rows to table as necessary. Be sure to note any annual emissions limitations from such permit(s) in Section 13 of this application.

Permit Number	Date Issued	Emission Point ID No.	Pollutant	BACT/LAER Limit[1]	Averaging Period	Description of Control Technology/Work Practice Standards

[1]For example, lb/MM Btu, ppmvd @ 15% O_2, lb/ton, lb/hr

18. Air Quality Dispersion Modeling [LAC 33:III.517.D.15]

Was Air Quality Dispersion Modeling as required by LAC 33:III performed in support of this permit application? (Air Quality Dispersion Modeling is only required when applying for PSD permits and as requested by LDEQ.)
☒ **Yes** ☐ **No**

*Has Air Quality Dispersion Modeling completed in accordance with LAC 33:III ever been performed for this facility in support of an air permit application previously submitted for this facility or process unit (for process unit-specific permits) or as required by other regulations **AND** approved by LDEQ?*
☐ **Yes** ☒ **No**

If yes, enter the date the most recent Air Quality Dispersion Modeling results as required by LAC 33:III were submitted:

_____

If the answer to either question above is "yes," enter a summary of the most recent results in the following table. If the answer to both questions is "no," enter "none" in the table. Add rows to table as necessary.

Pollutant	Time Period	Calculated Maximum Ground Level Concentration	Louisiana Toxic Air Pollutant Ambient Air Standard or (National Ambient Air Quality Standard {NAAQS})
Refer to the PSD Air Construction Permit Application Volume 2			

19. General Condition XVII Activities- ☐ Yes ☒ No

Enter all activities that qualify as Louisiana Air Emissions Permit General Condition XVII Activities.

- Expand this table as necessary to include all such activities.
- See instructions to determine what qualifies as a General Condition XVII Activity.
- Do not include emissions from General Condition XVII Activities in the proposed emissions totals for the permit application.

		Emission Rates – TPY					
Work Activity	**Schedule**	**PM_{10}**	**SO_2**	**NO_x**	**CO**	**VOC**	**Other**

20. Insignificant Activities [LAC 33:III.501.B.5] - ☒ Yes ☐ No

Enter all activities that qualify as Insignificant Activities.

- Expand this table as necessary to include all such activities.
- For sources claimed to be insignificant based on size or emission rate (LAC 33:III.501.B.5.A), information must be supplied to verify each claim. This may include but is not limited to operating hours, volumes, and heat input ratings.
- If aggregate emissions from all similar pieces of equipment claimed to be insignificant are greater than 5 tons per year for any pollutant, then the activities can not be claimed as insignificant and must be represented as permitted emission sources. Aggregate emissions shall mean the total emissions from a particular insignificant activity or group of similar insignificant activities (e.g., A.1, A.2, etc.) within a permit per year.

Emission Point ID No.	Description	Physical/Operating Data	Citation
AFST	Aviation Fuel Storage Tank	3,000 Gallons	LAC 33:III.501.B.5.A.3
CDT1	Crane Diesel Tank No. 1	3,000 Gallons	LAC 33:III.501.B.5.A.3
CDT2	Crane Diesel Tank No. 2	3,000 Gallons	LAC 33:III.501.B.5.A.3

21. Regulatory Applicability for Commonly Applicable Regulations – Answer all below [LAC 33:III.517.D.10]

Does this facility contain asbestos or asbestos containing materials? ☐ **Yes** ☒ **No**
If "yes," the facility or any portion thereof may be subject to 40 CFR 61, Subpart M, LAC 33:III.Chapter 27, and/or LAC 33:III.5151, and this application must address compliance as stated in Section 22 of this application

Is the facility or process unit represented in this permit subject to 40 CFR 68, or is any other process unit located at the same facility as the process unit represented in this application subject to 40 CFR 68? ☐ **Yes** ☒ **No**
If "yes," the entire facility is subject to 40 CFR 68 and LAC 33:III.Chapter 59, and this application must address compliance as stated in Section 22 of this application.

Is the facility listed in LAC 33:III.5611?

Table 5 ☐ **Yes** ☒ **No**

Table 6 ☐ **Yes** ☒ **No**

Table 7 ☐ **Yes** ☒ **No**

Does the applicant own or operate commercial refrigeration equipment normally containing more than 50 pounds of refrigerant at this facility or process unit? ☐ **Yes** ☒ **No**
If "yes," the entire facility is subject to 40 CFR 82, Subpart F, and this application must address compliance as stated in Section 22 of this application.

22. Applicable Regulations, Air Pollution Control Measures, Monitoring, and Recordkeeping

Important points for Table 1 [LAC 33:III.517.D.10]:

- List in Table 1, by Emission Point ID Number and Descriptive Name of the Equipment, state and federal pollution abatement programs and note the applicability or non-applicability of the regulations to each source.
- Adjust the headings for the columns in Table 1 as necessary to reflect all applicable regulations, in addition to any regulations that do not apply but require an explanation to substantiate this fact.
- For each piece of equipment, enter "1" for each regulation that applies. Enter "2" for each regulation that applies to this type of source, but from which this source of emissions is exempt. Enter "3" for equipment that is subject to a regulation, but does not have any applicable requirements. Also, enter "3" for each regulation that has applicable requirements that apply to the particular emission source, but the regulations currently do not apply due to meeting a specific criterion, such as it has not been constructed, modified, or reconstructed since the regulations have been in place.
- Leave the spaces blank when the regulations clearly would not apply under any circumstances to the source. For example, LAC 33:III.2103 – Storage of Volatile Organic Compounds would never apply to a steam generating boiler, no matter the circumstances.
- Consult instructions.

Important points for Table 2 [LAC 33:III.517.D.4; LAC 33:III.517.D.7; LAC 33:III.517.D.10]:

- For each piece of equipment listed in Table 2, include all applicable limitations, recordkeeping, reporting, monitoring, and testing requirements. Also, include any one-time notification or one-time performance test requirements that have not been fulfilled.
- Each of these regulatory aspects (limitations, recordkeeping, reporting, etc.) should be addressed for each regulation that is applicable to each emissions source or emissions point.
- For each regulation that provides a choice regarding the method of compliance, indicate the method of compliance that will be employed. It is not sufficient to state that all compliance options will be employed, though multiple compliance options may be approved as alternative operating scenarios.
- Consult instructions.

Important points for Table 3 [LAC 33:III.517.D.16]:

- Each time a 2 or a 3 is used to describe applicability of a source in Table 1, an entry should be made in Table 3 that explains the exemption or non-applicability status of the regulation to that source.
- Fill in all requested information in the table.
- The exact regulatory citation that provides for the specific exemption or non-applicability determination should be entered into the "Citation Providing for Exemption or Non-applicability" column.
- Consult Instructions.

Important points for Table 4 [LAC 33:III.517.D.18]

- List any single emission source that routes its emissions to another point where these emissions are commingled with the emissions of other sources before being released to the atmosphere. Do not list any single emission source in this table that does not route its emissions in this manner.
- List any and all emission sources that are routed as described above. This includes emission sources that do not otherwise appear in this permit application.
- Consult instructions.

TABLE 1: APPLICABLE LOUISIANA AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point	Description	LAC 33.III							LAC 33.III.Chapter									
		509	2103	2108	2111	2113	2115	2121	2	5	9	11	13	15	22	51	56	59
BMOP DWP Facility	BMOP DWP Facility	1		3		1		3	1	1	1	1	1	3		1	1	3
LPFL	Low Pressure Flare - Vapor Capture											1	1	3				
HPFL	High Pressure Flare - Natural Gas											1	1	3				
NGGEN1	Natural Gas Generator #1											2	1	3				
NGGEN2	Natural Gas Generator #2											2	1	3				
NGGEN CAP	Natural Gas Generators CAP																	
BCRANE1	Platform B Crane #1 (Diesel)											1	1	3		3		
BCRANE2	Platform B Crane #2 (Diesel)											1	1	3		3		
DGEN	Emergency Diesel Generator											1	1	3		3		
BFWP	Platform B Firewater Pump (Diesel)											1	1	3		3		
CFWP	Platform C Firewater Pump (Diesel)											1	1	3		3		
PDST	Primary Diesel Storage Tank		3															
SRGT	Surge Tank		2															
FUG	Facility Wide Fugitives				1			3								1		
UNLD1	Uncaptured Loading at Buoy #1																	
UNLD2	Uncaptured Loading at Buoy #2																	
UNLD CAP	Uncaptured Loading CAP																	
VCU1	VCU Stack 1											1	1	3				
VCU2	VCU Stack 2											1	1	3				
VCU3	VCU Stack 3											1	1	3				

KEY TO MATRIX

1 (Applicable) The regulations have applicable requirements that apply to this particular emissions source. This includes any monitoring, recordkeeping, or reporting requirements.
2 (Exempt) The regulations apply to this general type of emission source (i.e. vents, furnaces, towers, and fugitives) but do not apply to this particular emission source.
3 (Does Not Apply) The regulations do not apply to this emissions source. The regulations may have applicable requirements that could apply to this emissions source but the requirements do not currently apply to the source due to meeting a specific criterion, such as it has not been constructed, modified or reconstructed since the regulations have been in place.

TABLE 1: APPLICABLE LOUISIANA AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point	Description	40 C.F.R. Part 60 NSPS							40 C.F.R. Part 61 NESHAP	40 C.F.R. Part 63 NESHAP							40 C.F.R. Part			
		A	K	Ka	Kb	IIII	JJJJ	OOOOa	V	A	H	Y	HH	VV	EEEE	ZZZZ	64	68	72	82
BMOP DWP Facility	BMOP DWP Facility	1						3	3	1	3		3	3	3			3	3	1
LPFL	Low Pressure Flare - Vapor Capture																			
HPFL	High Pressure Flare - Natural Gas																			
NGGEN1	Natural Gas Generator #1	1					1			1						1				
NGGEN2	Natural Gas Generator #2	1					1			1						1				
NGGEN CAP	Natural Gas Generators CAP																			
BCRANE1	Platform B Crane #1 (Diesel)	1				1				1						1				
BCRANE2	Platform B Crane #2 (Diesel)	1				1				1						1				
DGEN	Emergency Diesel Generator	1				1				1						1				
BFWP	Platform B Firewater Pump (Diesel)	1				1				1						1				
CFWP	Platform C Firewater Pump (Diesel)	1				1				1						1				
PDST	Primary Diesel Storage Tank		3	3	3															
SRGT	Surge Tank		3	3	3															
FUG	Facility Wide Fugitives																			
UNLD1	Uncaptured Loading at Buoy #1																			
UNLD2	Uncaptured Loading at Buoy #2																			
UNLD CAP	Uncaptured Loading CAP																			
VCU1	VCU Stack 1									1		1					3			
VCU2	VCU Stack 2									1		1					3			
VCU3	VCU Stack 3									1		1					3			

KEY TO MATRIX

1 (Applicable) The regulations have applicable requirements that apply to this particular emissions source. This includes any monitoring, recordkeeping, or reporting requirements.
2 (Exempt) The regulations apply to this general type of emission source (i.e. vents, furnaces, towers, and fugitives) but do not apply to this particular emission source.
3 (Does Not Apply) The regulations do not apply to this emissions source. The regulations may have applicable requirements that could apply to this emissions source but the requirements do not currently apply to the source due to meeting a specific criterion, such as it has not been constructed, modified or reconstructed since the regulations have been in place.

Blank – The regulations clearly do not apply to this type of emission source.

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
BMOP DWP Facility	40 C.F.R. Part 60 Subpart A - General Provisions	**Requirements that limit emissions or operations-**			
		Comply with all applicable requirements to limit emissions or operations specified in 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.11 and § 60.18	N/A	No
		Requirements that specify monitoring-			
		Comply with all applicable monitoring requirements of 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.13	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Maintain all applicable records as required by 40 C.F.R Part 60 Subpart A.	40 C.F.R. § 60.7	N/A	No
		Requirements that specify reports to be submitted-			
		Submit all applicable reports as required by 40 C.F.R. Part 60 Subpart A.	40 C.F.R § 60.7 and § 60.19	N/A	No
		Requirements that specify performance testing-			
		Conduct applicable tests according to 40 C.F.R. § 60.8.	40 C.F.R. § 60.8	N/A	No
	40 C.F.R. Part 63 Subpart A - General Provisions	**Requirements that limit emissions or operations-**			
		Comply with all applicable requirements to limit emissions or operations specified in 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.6 and § 63.11	N/A	No
		Requirements that specify monitoring-			
		Comply with all applicable monitoring requirements of 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.8	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Maintain all applicable records as required by 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.10	N/A	No
		Requirements that specify reports to be submitted-			
		Submit all applicable reports as required by 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.9 and § 63.10	N/A	No
		Requirements that specify performance testing-			
		Conduct applicable tests according to 40 C.F.R. § 63.7.	40 C.F.R. § 63.7	N/A	No
	40 C.F.R. Part 82 - Stratospheric Ozone Provisions	**Requirements that limit emissions or operations-**			
		Comply with the standards for recycling and emissions reduction pursuant to 40 C.F.R. Part 82, Subpart F, except as provided for Motor Vehicle Air Conditioners (MVACs) in Subpart B.	40 C.F.R. 82 Subpart B, E, and F	N/A	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
BMOP DWP Facility (continued)	LAC 33:III Chapter 2 - Rules and Regulations for the Fee System of the Air Quality Control Programs	**Requirements that limit emissions or operations-**			
		Shall pay the prescribed application fee or annual fee, as determined by LAC 33:III.223, within 90 days after the due date.	LAC 33:III.219	90 Days After Application Due Date	No
	LAC 33:III Chapter 9 - General Regulations on Control of Emissions and Emission Standards	**Requirements that limit emissions or operations-**			
		No person or group of persons shall allow particulate matter or gases to become airborne in amounts which cause the ambient air quality standards to be exceeded. The limits stated include normal background levels of particulates and gases.	LAC 33:III.929.A	N/A	No
		Requirements that specify reports to be submitted-			
		Submit Emission Inventory (EI)/Annual Emissions Statement: Due annually, by the 30th of April to the Office of Environmental Services, for the reporting period of the previous calendar year that coincides with period of ownership or operatorship, until released from reporting, in writing, by DEQ. Submit both an emissions inventory and the certification statement required by LAC 33:III.919.F.1.c, separately for each AI, in a format specified by DEQ. To request a release from reporting, submit a completed Request for Release from Emissions Inventory Reporting form (form# 7365) to the Office of Environmental Services.	LAC 33:III.919	Annually	No
		Shall report the unauthorized discharge of any air pollutant into the atmosphere in accordance with LAC 33:I.Chapter 39. Submit written reports to the department pursuant to LAC 33:I.3925. Submit timely and appropriate follow-up reports detailing methods to be used to prevent similar atmospheric releases.	LAC 33:III.927	Upon Occurrence of an Unauthorized Discharge	No
		Requirements that specify performance testing-			
		New sources shall provide necessary sampling ports in stacks or ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices as may be necessary for proper determination of the emission of air contaminants.	LAC 33:III.913	N/A	No
	LAC 33:III Chapter 11 - Control of Emissions of Smoke	**Requirements that limit emissions or operations-**			
		Emissions of smoke which pass onto or across a public road and create a traffic hazard by impairing visibility as defined in LAC 33:III.111 or intensifying an existing traffic hazard condition are prohibited.	LAC 33:III.1103	N/A	No
	LAC 33:III Chapter 13 - Emission Standards for Particulate Matter	**Requirements that limit emissions or operations-**			
		Emissions of particulate matter which pass onto or across a public road and create a traffic hazard by impairment of visibility or intensify an existing traffic hazard condition are prohibited.	LAC 33:III.1303.B	N/A	No
	LAC 33:III Chapter 21 - Control of Emission of Organic Compounds	**Requirements that limit emissions or operations-**			
		Maintain best practical housekeeping and maintenance practices at the highest possible standards to reduce the quantity of organic compounds emissions. Good housekeeping shall include, but not be limited to, the practices listed in LAC 33:III.2113.A.1-5.	LAC 33:III.2113.A	N/A	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
BMOP DWP Facility (continued)	LAC 33:III Chapter 56 - Prevention of Air Pollution Emergency Episodes	**Requirements that limit emissions or operations-**			
		During an Air Pollution Alert, Air Pollution Warning or Air Pollution Emergency, make the standby plan available on the premises to any person authorized by DEQ to enforce these regulations.	LAC 33:III.5611.B.1	N/A	No
LPFL - Low Pressure Flare - Vapor Capture HPFL - High Pressure Flare - Natural Gas	LAC 33:III Chapter 11 - Control of Emissions of Smoke	**Requirements that limit emissions or operations-**			
		Opacity <= 20 percent; except for a combined total of six hours in any 10 consecutive day period, for burning in connection with pressure valve releases for control over process upsets.	LAC 33:III.1105	N/A	No
		Requirements that specify reports to be submitted-			
		Submit notification: Due to SPOC as soon as possible after the start of burning of pressure valve releases for control over process upsets. Notify in accordance with LAC 33:I.3923. Notification is required only if the upset cannot be controlled in six hours.	LAC 33:III.1105	N/A	No
	LAC 33:III.Chapter 13 - Emission Standards for Particulate Matter	**Requirements that limit emissions or operations-**			
		Opacity <= 20 percent; except emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.	LAC 33:III.1311.C	Six-minute	No
NGGEN1 - Natural Gas Generator #1 (2,328 hp) NGGEN2 - Natural Gas Generator #2 (2,328 hp)	40 CFR 60 Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines	**Requirements that limit emissions or operations-**			
		(Excluding Formaldehyde) VOC Total <= 0.7 g/hp-hr (60 ppmdv at 15%	40 CFR 60.4233(e)	N/A	No
		Carbon monoxide (CO) <= 2.0 g/hp-hr (270 ppmdv at 15% O_2).	40 CFR 60.4233(e)	N/A	No
		Nitrogen oxides (NO_X) <= 1.0 g/hp-hr (82 ppmdv at 15% O_2).	40 CFR 60.4233(e)	N/A	No
		Operate and maintain stationary SI ICE to achieve the emission standards as required in 40 CFR 60.4233 over the entire life of the engine.	40 CFR 60.4234	N/A	No
		Purchase a non-certified engine and demonstrate compliance with the emission standards specified in § 60.4233 (e) and according to the requirements specified in § 60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section.	40 CFR 60.4243(b)(2)	N/A	No
		Operate using propane for a maximum of 100 hours per year as an alternative fuel solely during emergency operations. Keep records of such use. If propane is used for more than 100 hours per year and the engine is not certified to the emission standards when using propane, conduct a performance test to demonstrate compliance with the emission standards of 40 CFR 60.4233.	40 CFR 60.4243(e)	N/A	No
		Requirements that specify monitoring -			
		It is expected that air-to-fuel ratio controllers will be used with the operation of three-way catalysts/non-selective catalytic reduction. The AFR controller must be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times.	40 CFR 60.4243(g)	Continuously	No
		Requirements that specify records to be kept and requirements that specify record retention time -			
		Keep a maintenance plan and records of conducted maintenance and must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions.	40 CF 60.4243(b)(2)(ii)	N/A	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
NGGEN1 - Natural Gas Generator #1 (2,328 hp) NGGEN2 - Natural Gas Generator #2 (2,328 hp) (continued)	40 CFR 60 Subpart JJJJ - Standards of Performance for Stationary Spark Ignition Internal Combustion Engines	Equipment/operational data recordkeeping by electronic or hard copy continuously. Keep records of the information in 40 CFR 60.4245(a)(1) through (a)(4).	40 CFR 60.4245(a)	N/A	No
		Requirements that specify reports to be submitted			
		Owners and operators of stationary SI ICE greater than or equal to 500 HP that have not been certified by an engine manufacturer to meet the emission standards in 40 CFR 60.4231 must submit an initial notification as required in 40 CFR 60.7(a)(1). The notification must include the information in 40 CFR 60.4245(c)(1)-(5).	40 CFR 60.4245(c)	N/A	No
		Owners and operators of stationary SI ICE that are subject to performance testing must submit a copy of each performance test as conducted in 40 CFR 60.4244 within 60 days after the test has been completed.	40 CFR 60.4245(d)	N/A	No
		Requirements that specify performance testing -			
		If the certified stationary SI internal combustion engine and control device is operated and maintained according to the manufacturer's emission-related written instructions, keep records of conducted maintenance to demonstrate compliance, but no performance testing is required. Meet the requirements as specified in 40 CFR part 1068, subparts A through D, as they apply.	40 CFR 60.4243(a)(1)	N/A	No
		If the certified stationary SI internal combustion engine and control device are not maintained according to the manufacturer's emission-related written instructions, the engine will be considered a non-certified engine, and you must demonstrate compliance according to (a)(2)(i) through (iii) of this section, as appropriate.	40 CFR 60.4243(a)(2)	N/A	No
		Purchasing a non-certified engine and demonstrating compliance with the emission standards specified in §60.4233(d) or (e) and according to the requirements specified in §60.4244, as applicable, and according to paragraphs (b)(2)(i) and (ii) of this section.	41 CFR 60.4243(b)(2)	N/A	No
		If purchasing a non-certified engine, conduct an initial performance test and conduct subsequent performance testing every 8,760 hours or 3 years, whichever comes first, thereafter to demonstrate compliance. Conduct performance tests by following the procedures in 40 CFR 60.4244(a) through (g).	40 CFR 60.4243(b)(2)(ii); 40 CFR 60.4244	Every 8,760 hours or 3 years	No
	40 CFR 63 Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	**Requirements that limit emissions or operations-**			
		A new stationary RICE located at an area source meets the requirements of this part (i.e., 40 CFR Part 63 Subpart ZZZZ) by meeting the requirements of 40 CFR Part 60, Subpart JJJJ. No further requirements apply under 40 CFR Part 63 Subpart ZZZZ.	40 CFR 63.6590(c)(1)	N/A	No
	LAC 33:III.Chapter 13 - Emission Standards for Particulate Matter	**Requirements that limit emissions or operations-**			
		Opacity <= 20 percent; except emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes. (Complies by using sweet natural gas as fuel)	LAC 33:III.1311.C	Six-minute	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
BCRANE1 - Platform B Crane #1 (475 hp, diesel) BCRANE2 - Platform B Crane #2 (475 hp, diesel)	40 C.F.R. Part 60 Subpart A - General Provisions	**Requirements that limit emissions or operations-**			
		Comply with all applicable requirements to limit emissions or operations specified in 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.11 and § 60.18	N/A	No
		Requirements that specify monitoring-			
		Comply with all applicable monitoring requirements of 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.13	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Maintain all applicable records as required by 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.7	N/A	No
		Requirements that specify reports to be submitted-			
		Submit all applicable reports as required by 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.7 and § 60.19	N/A	No
		Requirements that specify performance testing-			
		Conduct applicable tests according to 40 C.F.R. § 60.8.	40 C.F.R. § 60.8	N/A	No
	40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	**Requirements that limit emissions or operations-**			
		Shall comply with the emission standards for new CI engines in 40 CFR 60.4201 for their 2007 model year and later stationary CI ICE, as applicable.	40 CFR 60.4204(b)	N/A	No
		Stationary CI internal combustion engine manufacturers must certify their 2007 model year and later non-emergency stationary CI ICE with a maximum engine power less than or equal to 2,237 kilowatt (KW) (3,000 horsepower (HP)) and a displacement of less than 10 liters per cylinder to the certification emission standards for new nonroad CI engines in 40 CFR 89.112, 40 CFR 89.113, 40 CFR 1039.101, 40 CFR 1039.102, 40 CFR 1039.104, 40 CFR 1039.105, 40 CFR 1039.107, and 40 CFR 1039.115, as applicable, for all pollutants, for the same model year and maximum engine power.	40 CFR 60.4201(a)	N/A	No
		Shall operate and maintain stationary CI ICE that achieve the emission standards as required in 40 CFR 60.4204 over the entire life of this engine.	40 CFR 60.4206	Entire life of the engine	No
		Beginning October 1, 2010, shall use diesel fuel that meets the requirements of 40 CFR 80.510(b) for nonroad diesel fuel, except that any existing diesel fuel purchased (or otherwise obtained) prior to October 1, 2010, may be used until depleted.	40 CFR 60.4207(b)	N/A	No
		May not import or install stationary CI ICE that do not meet the applicable requirements in 40 CFR 60.4208.	40 CFR 60.4208	N/A	No
		In addition to the requirements specified in 40 CFR 60.4201, 60.4202, 60.4204, and 60.4205, it is prohibited to import stationary CI ICE with a displacement of less than 30 liters per cylinder that do not meet the applicable requirements specified in paragraphs (a) through (g) of this section after the dates specified in paragraphs (a) through (g) of this section.	40 CFR 60.4208(h)	N/A	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
BCRANE1 - Platform B Crane #1 (475 hp, diesel) BCRANE2 - Platform B Crane #2 (475 hp, diesel) (continued)	40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (continued)	Owner or operator that must comply with the emission standards in this subpart shall do the following: - Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions; - Change only those emission-related settings that are permitted by the manufacturer; and - Meet the requirements of 40 CFR parts 89, 94 and/or 1068, as they apply.	40 CFR 60.4211(a)(1) through (a)(3)	N/A	No
		As stated in 40 CFR 60.4218, comply with the applicable general provisions listed in Table 8.	40 CFR 60.4218; Table 8	N/A	No
		Shall comply by purchasing an engine certified to the emission standards in 40 CFR 60.4204(b) for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph 60.4211(g).	40 CFR 60.4211(c)	N/A	No
		If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must, to the extent practicable, maintain and operate the engine in a manner consistent with good air pollution control practice for minimizing emissions.	40 CFR 60.4211(g)	N/A	No
		Requirements that specify monitoring-			
		If you are an owner or operator of a stationary CI internal combustion engine equipped with a diesel particulate filter to comply with the emission standards in 40 CFR 60.4204, the diesel particulate filter must be installed with a backpressure monitor that notifies the owner or operator when the high backpressure limit of the engine is approached.	40 CFR 60.4209(b)	N/A	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
BCRANE1 - Platform B Crane #1 (475 hp, diesel) BCRANE2 - Platform B Crane #2 (475 hp, diesel) (continued)	40 CFR 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (continued)	**Requirements that specify records to be kept and requirements that specify record retention time-**			
		If the stationary CI internal combustion engine is equipped with a diesel particulate filter, the owner or operator must keep records of any corrective action taken after the backpressure monitor has notified the owner or operator that the high backpressure limit of the engine is approached.	40 CFR 60.4214(c)	N/A	No
		If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must keep a maintenance plan and records of conducted maintenance.	40 CFR 60.4211(g)	N/A	No
		Requirements that specify performance testing-			
		If you do not install, configure, operate, and maintain your engine and control device according to the manufacturer's emission-related written instructions, or you change emission-related settings in a way that is not permitted by the manufacturer, you must conduct an initial performance test to demonstrate compliance with the applicable emission standards within 1 year of startup, or within 1 year after an engine and control device is no longer installed, configured, operated, and maintained in accordance with the manufacturer's emission-related written instructions, or within 1 year after you change emission-related settings in a way that is not permitted by the	40 CFR 60.4211(g)(2)	N/A	No
		If performance test is required: conduct performance tests by following the procedures in 40 CFR 60.4212(a) through (e).	40 CFR 60.4212	N/A	No
	40 CFR 63 Subpart ZZZZ - National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal	**Requirements that limit emissions or operations -**			
		Meet the requirements of 40 CFR 63 by meeting the requirements of 40 CFR 60 Subpart IIII. No further requirements apply to such engines under 40 CFR 63.	40 CFR 63.6590(c)(7)	N/A	No
	LAC 33:III.Chapter 11 - Control of Emissions of Smoke	**Requirements that limit emissions or operations -**			
		Shall control the emission of smoke generated by the burning of fuel or combustion of waste material in a combustion unit, including the incineration of industrial, commercial, institutional and municipal wastes so that the shade or appearance of the emission is not darker than 20 percent average opacity, except that such emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.	LAC 33:III.1101.B	One six-minute period in any 60 consecutive minutes.	No
	LAC 33:III.Chapter 13 - Emission Standards for Particulate Matter	**Requirements that limit emissions or operations -**			
		Emissions of particulate matter shall be controlled so that the shade or appearance of the emission is not denser than 20 percent average opacity, except the emissions may have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.	LAC 33:III.1311.C	6 minutes in any 60 consecutive minutes	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
DGEN - Emergency Generator (450 hp, diesel) BFWP - Platform B Firewater Pump (650 hp, diesel) CFWP - Platform C Firewater Pump (650 hp, diesel)	40 C.F.R. Part 60 Subpart A - General Provisions	**Requirements that limit emissions or operations-**			
		Comply with all applicable requirements to limit emissions or operations specified in 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.11 and § 60.18	N/A	No
		Requirements that specify monitoring-			
		Comply with all applicable monitoring requirements of 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.13	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Maintain all applicable records as required by 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.7	N/A	No
		Requirements that specify reports to be submitted-			
		Submit all applicable reports as required by 40 C.F.R. Part 60 Subpart A.	40 C.F.R. § 60.7 and § 60.19	N/A	No
		Requirements that specify performance testing-			
		Conduct applicable tests according to 40 C.F.R. § 60.8.	40 C.F.R. § 60.8	N/A	No
	40 C.F.R. Part 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines	**Requirements that limit emissions or operations-**			
		For the emergency generators: comply with the NMHC + NO_X, CO, and PM emission limitations set forth in Table 1 for the highest tier of the appropriate sized engine. All emergency generators are subject to the following standards: • CO limit of 3.5 g/kW-hr • PM limit of 0.20 g/kW-hr Engines greater than 560 kilowatts (kW) are subject to the following standard: • NMHC + NO_X limit of 6.4 g/kW-hr Engines with a rated power between 225-560 kW are subject to the following standard: • NMHC + NO_X limit of 4.0 g/kW-hr	40 C.F.R. § 60.4202(a)(2),40 C.F.R. § 60.4202(b)(2), 40 C.F.R. § 89.112(a) Table 1	Per underlying Test Method	No
		For the emergency generators: exhaust opacity from CI nonroad engines (excluding single-cylinder engines, propulsion marine diesel engines, and constant speed engines) may not exceed: • 20% during the acceleration mode; • 15% during the lugging mode; and • 50% during the peaks in either the acceleration or lugging modes.	40 C.F.R. § 60.4202(b)(2), 40 C.F.R. § 89.113	Per 40 C.F.R.§ 89.113	No
		For the fire pumps: comply with the NMHC + NO_X and PM emission limitations set forth in 40 C.F.R. Part 60 Subpart IIII Table 4 for 600-750 hp engines, 2009 model year and later.	40 C.F.R. § 60.4205(c), 40 C.F.R. Part 60 Subpart IIII Table 4	Per underlying Test Method	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
DGEN - Emergency Generator (450 hp, diesel) BFWP - Platform B Firewater Pump (650 hp, diesel) CFWP - Platform C Firewater Pump (650 hp, diesel) (continued)	40 C.F.R. Part 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (continued)	Operate and maintain stationary CI ICE that achieve the emission standards as required in 40 C.F.R. 60.4204 and 40 C.F.R. 60.4205 over the entire life of the engine.	40 C.F.R. § 60.4206	N/A	No
		Use diesel fuel with a maximum sulfur content of 15 ppm. Use diesel fuel with a minimum cetane index of 40 or a maximum aromatic content of 35 volume %.	40 C.F.R. § 60.4207(b), 40 C.F.R. § 80.510(b)	Continuously	No
		If the emergency stationary CI internal combustion engine does not meet the standards applicable to non-emergency engines, install a non-resettable hour meter prior to startup of the engine.	40 C.F.R. § 60.4209(a)	N/A	No
		Operate and maintain the stationary CI internal combustion engine and control device according to the manufacturer's emission-related written instructions, change only those emission related settings that are permitted by the manufacturer, and meet the requirements of 40 C.F.R. Part 89, 94, and/or 1068, as they apply.	40 C.F.R. § 60.4211(a)	N/A	No
		Purchase an engine certified to the emission standards in 40 C.F.R. § 60.4204(b), § 60.4205(b), or § 60.4205(c), as applicable, for the same model year and maximum engine power. The engine must be installed and configured according to the manufacturer's emission-related specifications, except as permitted in 40 C.F.R. § 60.4211(g).	40 C.F.R. § 60.4211(c)	N/A	No
		Operate according to the requirements in 40 C.F.R. 60.4211(f)(1), (f)(2)(i), and (f)(3). In order for the engine to be considered an emergency stationary ICE under 40 C.F.R. 60 Subpart IIII, any operation other than as described in 40 C.F.R. 60.4211(f)(1), (f)(2)(i), and (f)(3) is prohibited. If the engine is not operated according to these requirements, the engine will not be considered an emergency engine under 40 C.F.R. 60 Subpart IIII and must meet all requirements for non-emergency engines.	40 C.F.R. § 60.4211(f)	N/A	No
		There is no time limit on the use of emergency stationary ICE in emergency situations.	40 C.F.R. § 60.4211(f)(1)	N/A	No
		Operate for maintenance checks and readiness testing for a maximum of 100 hours per calendar year, provided that the tests are recommended by the federal, state or local government; the manufacturer; the vendor; the regional transmission organization or equivalent balancing authority and transmission operator; or the insurance company associated with the engine. LDEQ may be petitioned for approval of additional hours to be used for maintenance checks and readiness testing, but a petition is not required if records are maintained indicating that federal, state, or local standards require maintenance and testing of emergency ICE beyond 100 hours per calendar year.	40 C.F.R. § 60.4211(f)(2)(i)	N/A	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
DGEN - Emergency Generator (450 hp, diesel) BFWP - Platform B Firewater Pump (650 hp, diesel) CFWP - Platform C Firewater Pump (650 hp, diesel) (continued)	40 C.F.R. Part 60 Subpart IIII - Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (continued)	Operate for up to 50 hours per calendar year in non-emergency situations. Count the 50 hours of operation in non-emergency situations as part of the 100 hours per calendar year for maintenance and testing provided in 40 C.F.R. 60.4211(f)(2)(i). Do not use the 50 hours per calendar year for non-emergency situations for peak shaving or non-emergency demand response, or to generate income for a facility to an electric grid or otherwise supply power as part of a financial arrangement with another entity, except as provided in 40 C.F.R. 60.4211(f)(3)(i).	40 C.F.R. § 60.4211(f)(3)	N/A	No
		Comply with applicable requirements in Table 8 to Subpart IIII of Part 60.	40 C.F.R. § 60.4218, Table 8 to Subpart IIII of Part 60	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Operating time recordkeeping by electronic or hard copy upon occurrence of event. If the emergency engine meets the standards applicable to emergency engines in the applicable model year, keep records of the operation of the engine in emergency and non-emergency service that are recorded through the non-resettable hour meter. Record the time of operation of the engine and the reason the engine was in operation during that time.	40 C.F.R. § 60.4214(b)	N/A	N/A

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
DGEN - Emergency Generator (450 hp, diesel) BFWP - Platform B Firewater Pump (650 hp, diesel) CFWP - Platform C Firewater Pump (650 hp, diesel) (continued)	40 C.F.R. Part 63 Subpart A - General Provisions	**Requirements that limit emissions or operations-**			
		Comply with all applicable requirements to limit emissions or operations specified in 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.6 and § 63.11 as per 63.6665	N/A	No
		Requirements that specify monitoring-			
		Comply with all applicable monitoring requirements of 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.8 as per 63.6665	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Maintain all applicable records as required by 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.10 as per 63.6665	N/A	No
		Requirements that specify reports to be submitted-			
		Submit all applicable reports as required by 40 C.F.R. Part 63 Subpart A.	40 C.F.R. § 63.9 and § 63.10 as per 63.6665	N/A	No
		Requirements that specify performance testing-			
		Conduct applicable tests according to 40 C.F.R. § 63.7.	40 C.F.R. § 63.7 as per 63.6665	N/A	No
	40 C.F.R. Part 63 Subpart ZZZZ - National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	**Requirements that specify reports to be submitted-**			
		RICE with Capacities Greater Than 500 Horsepower: Per 40 C.F.R. § 63.6590(b)(1)(i), new emergency stationary RICE with a site rating of more than 500 brake horsepower located at a major HAP source that do not operate or are not contractually obligated to be available for more than 15 hours per calendar year for the purposes specified in 40 C.F.R. § 63.6640(f)(2)(ii) and (iii) do not have to meet the requirements of Subpart ZZZZ and Subpart A except for the initial notification requirements of 40 C.F.R. § 63.6645(f).	40 C.F.R. § 63.6590(b)(1)(i), 40 C.F.R. § 63.6645(f)	N/A	No
	LAC 33:III Chapter 11 - Control of Emissions of Smoke	**Requirements that limit emissions or operations-**			
		Opacity <= 20 percent, except for emissions that have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes. Determine opacity by using Method 9 of 40 C.F.R. Part 60, Appendix A or by using a continuous opacity monitoring system (COMS) meeting the requirements outlined in 40 C.F.R. 60.13(c) and (d).	LAC 33:III.1101.B	6 Minutes in any 60 Minute Consecutive Period	No
	LAC 33:III Chapter 13 - Emission Standards for Particulate Matter	**Requirements that limit emissions or operations-**			
		Opacity <= 20 percent, except for emissions that have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.	LAC 33:III.1311.C	6 Minutes in any 60 Minute Consecutive Period	No

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
FUG - Facility Wide Fugitives	LAC 33:III Chapter 2111 - Pumps And Compressors	**Requirements that limit emissions or operations-**			
		Equip all rotary pumps and compressors handling volatile organic compounds having a true vapor pressure of 1.5 psia or greater at handling conditions with mechanical seals or other equivalent equipment.	LAC 33:III.2111	N/A	No
	LAC 33:III Chapter 51 - Comprehensive Toxic Air Pollutant Emission Control Program	**Requirements that specify reports to be submitted -**			
		Emissions to be reported in facility-wide report.	LAC 33:III.5107.A	N/A	Yes
VCU1, 2, & 3 - VCU Stacks 1, 2, & 3	40 CFR 63 Subpart Y - National Emission Standards for Hazardous Air Pollutants from Marine Tank Loading Operations	**Requirements that limit emissions or operations-**			
		Operate a vapor collection system to collect HAP vapors displaced from marine tank vessels during loading operations and to prevent HAP vapors collected at one loading berth from passing through another loading berth into the atmosphere.	40 CFR 63.562(b)(1)(i)	N/A	No
		Limit marine tank vessel loading operations to vessels equipped with vapor collection equipment that is compatible with the terminal's vapor collection system.	40 CFR 63.562(b)(1)(ii)	N/A	No
		Limit marine tank vessel loading operations to vessels which are vapor tight and connected to the vapor collection system.	40 CFR 63.562(b)(1)(iii)	N/A	No
		Reduce HAP emissions from marine tank vessel loading operations by 95 weight percent.	40 CFR 63.562(b)(4)	N/A	No
		Option to apply for a maintenance allowance for loading berths based on a percent of annual throughput of annual marine tank vessel loading operation time.	40 CFR 63.562(b)(6)	N/A	No
		Operate and maintain the source, including associated air pollution control equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions.	40 CFR 63.562(e)	N/A	No
		Develop a written operation and maintenance plan that describes in detail a program of corrective action for varying air pollution control equipment and monitoring equipment used to comply with the MACT standard.	40 CFR 63.562(e)	N/A	No
		Follow vapor-tightness requirements for the marine vessels to be loaded.	40 CFR 63.563(a)(4)	N/A	No
		Requirements that specify monitoring-			
		Determine continuing compliance of the VCU control system by monitoring for outlet VOC concentration or temperature in accordance with 40 CFR § 63.564.	40 CFR 63.564	N/A	No
		Requirements that specify records to be kept and requirements that specify record retention time-			
		Records of all maintenance performed on the air pollution control equipment shall be maintained.	40 CFR 63.562(b)(6)	N/A	No
		Requirements that specify performance testing-			
		Perform an initial performance test of the VCU control system according to 40 CFR § 63.563(b)(1).	40 CFR 63.563(b)(1)	N/A	N/A

TABLE 2. STATE AND FEDERAL AIR QUALITY REQUIREMENTS

Emission Point ID No.:	Applicable Requirement	Compliance Method/Provision	Compliance Citation	Averaging Period/Frequency	State Only Requirement
VCU1, 2, & 3 - VCU Stacks 1, 2, & 3 (Continued)	LAC 33.III.Chapter 11	**Requirements that limit emissions or operations-**			
		Opacity <= 20 percent, except for emissions that have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.	LAC 33:III.1101.B	6 Minutes in any 60 Minute Consecutive Period	No
	LAC 33.III.Chapter 13	**Requirements that limit emissions or operations-**			
		Opacity <= 20 percent, except for emissions that have an average opacity in excess of 20 percent for not more than one six-minute period in any 60 consecutive minutes.	LAC 33:III.1311.C	6 Minutes in any 60 Minute Consecutive Period	No

TABLE 3. EXPLANATION FOR EXEMPTION STATUS OR NON-APPLICABILITY OF A SOURCE

Emission Point ID No:	Requirement	Exempt or Does Not Apply	Explanation	Citation Providing for Exemption or Non-applicability
BMOP DWP Facility	NSPS Subpart OOOOa - Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution [40 C.F.R. Part 60 Subpart OOOOa]	Does Not Apply	The facility is an offshore platform.	40 C.F.R. § 60.5365a
	NESHAP Subpart V - National Emission Standards for Hazardous Air Pollutants for Equipment Leaks (Fugitive Emission Sources) [40 C.F.R. Part 61 Subpart V]	Does Not Apply	Project components will not operate in volatile hazardous air pollutant (VHAP) service.	40 C.F.R. § 61.240(a)
	NESHAP Subpart H - National Emission Standards for Hazardous Air Pollutants for Equipment Leaks [40 C.F.R. Part 63 Subpart H]	Does Not Apply	No Part 63 subpart that applies to the Project references Subpart H.	40 C.F.R. § 63.160(a)
	NESHAP Subpart HH - National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities [40 C.F.R. Part 63 Subpart HH]	Does Not Apply	The facility is not a production facility of oil and natural gas.	40 C.F.R. § 63.760
	NESHAP Subpart VV - National Emission Standards for Hazardous Air Pollutants for Oil-Water Separators and Organic-Water Separators [40 C.F.R. Part 63 Subpart VV]	Does Not Apply	No Part 63 subpart that applies to the Project references Subpart VV.	40 C.F.R. § 63.1040
	NESHAP Subpart EEEE - National Emission Standards for Hazardous Air Pollutants: Organic Liquids Distribution (Non-Gasoline) [40 C.F.R. Part 63 Subpart EEEE]	Does Not Apply	The definition storage vessel specifically excludes surge control vessels. The other storage tanks proposed do not store an organic liquid as defined in the rule (excludes diesel, and fuels used for refueling). The project will not include a transfer rack, as the delivery of crude is to marine vessel, not to a cargo tank or tank car. Thus this subpart does not apply.	40 C.F.R. 63.2406
	Chemical Accident Prevention Provisions [40 C.F.R. Part 68]	Does Not Apply	Facility does not produce, process, handle, or store any substance listed greater than the threshold amounts.	40 C.F.R. § 68
	Acid Rain Program General Provisions [40 C.F.R. Part 72]	Does Not Apply	The units at the facility are non-utility units, and non-utility units are not subject to the Acid Rain Program.	40 C.F.R. § 72.6(b)(8)
	Emission Standards for Sulfur Dioxide [LAC 33:III.Chapter 15]	Does Not Apply	No single point source emits or has the potential to emit 5 tons per year or more of SO_2.	LAC 33:III.1502.A.3
	Marine Vapor Recovery [LAC 33:III.Chapter 2108]	Does Not Apply	This facility is located offshore, not onshore in any of the Louisiana parishes. Therefore, this regulation does not apply.	LAC 33:III.2108
	Fugitive Emission Control [LAC 33:III.Chapter 2121]	Exempt	Facility is not one of the facility types subject to this regulation; the definition of natural gas processing plant excludes compressor stations, dehydration units, sweetening units, field treatment, underground storage facilities, liquefied natural gas units, and field gas gathering systems.	LAC 33:III.2121.A
	Chemical Accident Prevention and Minimization of Consequences [LAC 33:III.Chapter 59]	Does Not Apply	Facility does not produce, process, handle, or store any substance listed greater than the threshold amounts.	LAC 33:III.5907

TABLE 3. EXPLANATION FOR EXEMPTION STATUS OR NON-APPLICABILITY OF A SOURCE

Emission Point ID No:	Requirement	Exempt or Does Not Apply	Explanation	Citation Providing for Exemption or Non-applicability
LPFL HPFL	Emission Standards for Sulfur Dioxide [LAC 33:III.Chapter 15]	Does not apply	The units will not emit 5 tons per year or more of SO_2 to the atmosphere.	LAC 33:III.1502.A.3
NGGEN1 NGGEN2	Control of Emissions of Smoke [LAC 33:III.Chapter 11]	Exempt	The units will burn only natural gas and are exempt from the requirements of LAC 33:III.1101.	LAC 33:III.1107.B.1
	Emission Standards for Sulfur Dioxide [LAC 33:III.Chapter 15]	Does not apply	The units will not emit 5 tons per year or more of SO_2 to the atmosphere.	LAC 33:III.1502.A.3
	Control of Emissions of Nitrogen Oxides (NO_X) [LAC 33:III. Chapter 22]	Does not apply	The facility is not located in a non-attainment area or the region of influence.	LAC 33:III.2201.A
BCRANE1 BCRANE2 DGEN BFWP CFWP	Emission Standards for Sulfur Dioxide [LAC 33:III.Chapter 15]	Does Not Apply	Each unit emits less than 5 tons per year of sulfur dioxide. Shall record and retain data to show annual potential emissions from each unit.	LAC 33:III.1502.A.3 and 1513.C
	LAC 33:III Chapter 51 - Comprehensive Toxic Air Pollutant Emission Control Program [LAC 33:III.Chapter 51]	Exempt	TAP emissions are from the combustion of Group 1 virgin fossil fuels.	LAC 33:III.5105.B.3.a
PDST SRGT	NSPS Subpart K - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After June 11, 1973, and Prior to May 19, 1978 [40 C.F.R. Part 63 Subpart K]	Does Not Apply	Storage Tank constructed after May 19, 1978.	40 C.F.R. § 60.110(c)(1).
	NSPS Subpart Ka - Standards of Performance for Storage Vessels for Petroleum Liquids for Which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and Prior to July 23, 1984 [40 C.F.R. Part 63 Subpart Ka]	Does Not Apply	Storage Tank constructed after July 23, 1984.	40 C.F.R. § 60.110a
PDST	NSPS Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 [40 C.F.R. Part 63 Subpart Kb]	Does Not Apply	The storage capacity for each of the tank is less than 75 $m.^3$	40 C.F.R. § 60.110b(a).
	Control of Emissions of Organic Compounds - Storage of Volatile Organic Compounds [LAC 33:III:2103]	Does Not Apply	Tank will store diesel which has a vapor pressure of lower than 1.5 psia; therefore, the requirements of LAC 33:III.2103 are not applicable.	LAC 33:III 2103.B

TABLE 3. EXPLANATION FOR EXEMPTION STATUS OR NON-APPLICABILITY OF A SOURCE

Emission Point ID No:	Requirement	Exempt or Does Not Apply	Explanation	Citation Providing for Exemption or Non-applicability
SRGT	NSPS Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 [40 C.F.R. Part 63 Subpart Kb]	Does Not Apply	The surge tank is potentially subject to NSPS Subpart Kb. However, the surge tank is considered a process tank. The definition storage vessel specifically excludes process tanks. Thus subpart Kb does not apply.	40 C.F.R. § 60.111b
	LAC 33:III Chapter 2103 - Storage of Volatile Organic Compounds	Exempt	Storage tank is used for crude oil or condensate and having a nominal storage capacity of less than 420,000 gallons and storage tank is NOT subject to New Source Performance Standards;	LAC 33:III 2103.G.1
FUG	Fugitive Emission Control [LAC 33:III.Chapter 2121]	Exempt	Facility is not one of the facility types subject to this regulation; the definition of natural gas processing plant excludes compressor stations, dehydration units, sweetening units, field treatment, underground storage facilities, liquefied natural gas units, and field gas gathering systems.	LAC 33:III.2121.A
VCU 1, 2, and 3	Compliance Assurance Monitoring [40 C.F.R. Part 64]	Does Not Apply	The requirements of 40 CFR 64 shall not apply to emission limitations or standards proposed by the Administrator after November 15, 1990 pursuant to section 111 or 112 of the Act.	40 CFR 64.2(b)(1)(i)
	Emission Standards for Sulfur Dioxide [LAC 33:III.Chapter 15]	Does Not Apply	No single point source emits or has the potential to emit 5 tons per year or more of SO_2.	LAC 33:III.1502.A.3

TABLE 4. EQUIPMENT LIST

Emission Point ID No:	Description	Construction Date	Routes to:	Operating Rate/Volume	Applicable Requirement(s)?
NGGEN1	Natural Gas Generator #1	Proposed	NGGEN CAP	17,820 scf/hr	Yes
NGGEN2	Natural Gas Generator #2	Proposed	NGGEN CAP	17,820 scf/hr	Yes
UNLD1	Uncaptured Loading at Buoy #1	Proposed	UNLD CAP	80,000 bbl/hr	No
UNLD2	Uncaptured Loading at Buoy #2	Proposed	UNLD CAP	80,000 bbl/hr	No
UNLD1	Uncaptured Loading at Buoy #1	Proposed	VCU 1, 2, or 3	80,000 bbl/hr	No
UNLD2	Uncaptured Loading at Buoy #2	Proposed	VCU 1, 2, or 3	80,000 bbl/hr	No

23. Emissions Inventory Questionnaire (EIQ) Forms [LAC 33:III.517.D.3; 517.D.6]

Complete one (1) EIQ for:

- Each emission source. If two emission sources have a common stack, the applicant may submit one EIQ sheet for the common emissions point. Note any emissions sources that route to this common point in Table 4 of the application.
- Each emissions CAP that is proposed, including each source that is part of the CAP.
- Each alternate operating scenario that a source may operate under. Some common scenarios are:
    1. Sources that combust multiple fuels
    2. Sources that have startup/shutdown max lb/hr emission rates higher than the max lb/hr for normal operating conditions would need a separate EIQ addressing the startup/shutdown emission rates
- Fugitive emissions releases. One (1) EIQ should be completed for each of the following types of fugitive emissions sources or emissions points:
    1. Equipment leaks.
    2. Non-equipment leaks (i.e., road dust, settling ponds, etc).

For each EIQ:

- Fill in all requested information.
- Speciate all Toxic Air Pollutants and Hazardous Air Pollutants emitted by the source.
- Use appropriate significant figures.
- Consult instructions.

The EIQ is in Microsoft Word Excel. Visit the following website to get to the EIQ form.
http://deq.louisiana.gov/page/air-permit-applications

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
UNLD CAP	Uncaptured Loading CAP	Method ____ Datum ____
Tempo Subject Item ID No.		UTM Zone ____ Horizontal ____ mE Vertical ____ mN
		Latitude ____ ° ____ ' ____ " ____ hundredths
		Longitude ____ ° ____ ' ____ " ____ hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	N/A ft N/A ft^2	N/A ft	N/A ft/sec	N/A ft^3/min	N/A °F	8,760 hr/yr	proposed	25%	25%	25%	25%

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a		
	b		
	c		

Notes

This emissions CAP includes emissions from Uncaptured Loading Buoy 1 (UNLD1) and Uncaptured Loading Buoy 2 (UNLD2). See individual EIQs for max hourly emissions and stack information.

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	605,000,000	bbl/yr
Maximum Operating Rate/Throughput	700,800,000	bbl/yr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered			Engine Model Year	
Date Engine Was Built by Manufacturer				

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): UNLD CAP Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Permitted Emission Rate (Current) Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Total VOC (including those listed below)				4552.92	--	1604.05	--	A		ppm by vol
Hydrogen sulfide			07783-06-4	1.98	--	0.70	--	A		ppm by vol
n-Hexane			00110-54-3	186.21	--	65.60	--	A		ppm by vol
Benzene			00071-43-2	36.44	--	12.84	--	A		ppm by vol
Toluene			00108-88-3	16.18	--	5.70	--	A		ppm by vol
Ethyl benzene			00100-41-4	2.26	--	0.80	--	A		ppm by vol
1,2,4 - Trimethylbenzene				0.49	--	0.17	--	A		ppm by vol

Emission Point ID No. (Designation) UNLD CAP Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
1,3-dimethylbenzene				2.17	--	0.76	--	A		ppm by vol
1,4-dimethylbenzene				1.51	--	0.53	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	9.46	--	3.33	--	A		ppm by vol
Cumene			00098-82-8	0.27	--	0.09	--	A		ppm by vol
Cresol			01319-77-3	0.03	--	0.01	--	A		ppm by vol
Naphthalene			00091-20-3	0.03	--	0.01	--	A		ppm by vol
Phenol			00108-95-2	0.07	--	0.02	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
UNLD1	Uncaptured Loading at Buoy #1	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499627.30 mE Vertical: 3147270.30 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	2.17 ft	36.09 ft	33.74 ft/sec	7,486.11 ft^3/min	90 °F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a		
	b		
	c		

Notes

Average hourly and annual emissions permitted under Uncaptured Loading CAP.

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	80,000	bbl/hr
Maximum Operating Rate/Throughput	80,000	bbl/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof Floating Roof ☐ External ☐ Internal

Date Engine Ordered			Engine Model Year	
Date Engine Was Built by Manufacturer				

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): UNLD1	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Total VOC (including those listed below)				--	4989.04	--	--	A		ppm by vol
Hydrogen sulfide			07783-06-4	--	64.55	--	--	A		ppm by vol
n-Hexane			00110-54-3	--	204.04	--	--	A		ppm by vol
Benzene			00071-43-2	--	39.93	--	--	A		ppm by vol
Toluene			00108-88-3	--	17.73	--	--	A		ppm by vol
Ethyl benzene			00100-41-4	--	2.48	--	--	A		ppm by vol
1,2,4 - Trimethylbenzene				--	0.53	--	--	A		ppm by vol

Emission Point ID No. (Designation) UNLD1 Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
1,3-dimethylbenzene				--	2.38	--	--	A		ppm by vol
1,4-dimethylbenzene				--	1.66	--	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	--	10.36	--	--	A		ppm by vol
Cumene			00098-82-8	--	0.29	--	--	A		ppm by vol
Cresol			01319-77-3	--	0.04	--	--	A		ppm by vol
Naphthalene			00091-20-3	--	0.03	--	--	A		ppm by vol
Phenol			00108-95-2	--	0.07	--	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
UNLD2	Uncaptured Loading at Buoy #2	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 501099.00 mE Vertical: 3146871.60 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	2.17 ft	36.09 ft	33.74 ft/sec	7,486.11 ft^3/min	90 °F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a		
	b		
	c		

Notes

Average hourly and annual emissions permitted under Uncaptured Loading CAP.

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	80,000	bbl/hr
Maximum Operating Rate/Throughput	80,000	bbl/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof Floating Roof ☐ External ☐ Internal

Date Engine Ordered			Engine Model Year	
Date Engine Was Built by Manufacturer				

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): UNLD2	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Total VOC (including those listed below)				--	4989.04	--	--	A		ppm by vol
Hydrogen sulfide			07783-06-4	--	64.55	--	--	A		ppm by vol
n-Hexane			00110-54-3	--	204.04	--	--	A		ppm by vol
Benzene			00071-43-2	--	39.93	--	--	A		ppm by vol
Toluene			00108-88-3	--	17.73	--	--	A		ppm by vol
Ethyl benzene			00100-41-4	--	2.48	--	--	A		ppm by vol
1,2,4 - Trimethylbenzene				--	0.53	--	--	A		ppm by vol

Emission Point ID No. (Designation) UNLD2	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				**Average (lb/hr)**	**Maximum (lbs/hr)**	**Annual (tons/yr)**	**Annual (tons/yr)**			
1,3-dimethylbenzene				--	2.38	--	--	A		ppm by vol
1,4-dimethylbenzene				--	1.66	--	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	--	10.36	--	--	A		ppm by vol
Cumene			00098-82-8	--	0.29	--	--	A		ppm by vol
Cresol			01319-77-3	--	0.04	--	--	A		ppm by vol
Naphthalene			00091-20-3	--	0.03	--	--	A		ppm by vol
Phenol			00108-95-2	--	0.07	--	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
NGGEN CAP	Natural Gas Generator CAP	Method ____ Datum ____
Tempo Subject Item ID No.		UTM Zone ____ Horizontal ____ mE Vertical ____ mN
		Latitude ____ ° ____ ' ____ " ____ hundredths
		Longitude ____ ° ____ ' ____ " ____ hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	N/A ft N/A ft^2	N/A ft	N/A ft/sec	N/A ft^3/min	N/A °F	8,760 hr/yr	proposed	25%	25%	25%	25%

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a		
	b		
	c		

Notes

This emissions CAP includes emissions from NG Generator No 1 (NGGEN1) and NG Generator No 2 (NGGEN2). See individual EIQs for max hourly emissions and stack information.

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	156.10	MMscf/yr
Maximum Operating Rate/Throughput	156.10	MMscf/yr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof Floating Roof ☐ External ☐ Internal

Date Engine Ordered			Engine Model Year	
Date Engine Was Built by Manufacturer				

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): NGGEN CAP Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Permitted Emission Rate (Current): Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Particulate matter (PM_{10})				0.18	--	0.80	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				0.18	--	0.80	--	A		gr/std ft^3
Sulfur dioxide				0.01	--	0.05	--	A		ppm by vol
Nitrogen oxides				2.57	--	11.24	--	A		ppm by vol
Carbon monoxide				1.18	--	5.17	--	A		ppm by vol
Total VOC (including those listed below)				1.44	--	6.29	--	A		ppm by vol
Sulfuric Acid			07664-93-9	<0.001	--	<0.01	--	A		ppm by vol

Emission Point ID No. (Designation) NGGEN CAP Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Acetaldehyde			00075-07-0	0.15	--	0.67	--	A		ppm by vol
Acrolein			00107-02-8	0.09	--	0.41	--	A		ppm by vol
Benzene			00071-43-2	0.01	--	0.04	--	A		ppm by vol
Biphenyl			00092-52-4	0.004	--	0.02	--	A		ppm by vol
1,3-Butadiene			00106-99-0	0.005	--	0.02	--	A		ppm by vol
Carbon tetrachloride			00056-23-5	<0.001	--	<0.01	--	A		ppm by vol
Chlorobenzene			00108-90-7	<0.001	--	<0.01	--	A		ppm by vol
Chloroform			00067-66-3	<0.001	--	<0.01	--	A		ppm by vol
1,3-Dichloropropene			00542-75-6	<0.001	--	<0.01	--	A		ppm by vol
Ethyl benzene			00100-41-4	<0.001	--	<0.01	--	A		ppm by vol
1,2-Dibromoethane			00106-93-4	<0.001	--	<0.01	--	A		ppm by vol
Formaldehyde			00050-00-0	0.61	--	2.67	--	A		ppm by vol
Methanol			00067-56-1	0.05	--	0.20	--	A		ppm by vol
Dichloromethane			00075-09-2	<0.001	--	<0.01	--	A		ppm by vol
2-Methylnaphthalene			00091-57-6	<0.001	--	<0.01	--	A		ppm by vol
n-Hexane			00110-54-3	0.02	--	0.09	--	A		ppm by vol
Naphthalene			00091-20-3	0.001	--	0.01	--	A		ppm by vol
Polynuclear Aromatic Hydrocarbons				<0.001	--	<0.01	--	A		ppm by vol
Phenanthrene				<0.001	--	<0.01	--	A		ppm by vol
Phenol			00108-95-2	<0.001	--	<0.01	--	A		ppm by vol
Styrene			00100-42-5	<0.001	--	<0.01	--	A		ppm by vol
Toluene			00108-88-3	0.01	--	0.03	--	A		ppm by vol
1,1,2,2-Tetrachloroethane			00079-34-5	<0.001	--	<0.01	--	A		ppm by vol
1,1,2-Trichloroethane			00079-00-5	<0.001	--	<0.01	--	A		ppm by vol
2,2,4-Trimethylpentane			00540-84-1	0.005	--	0.02	--	A		ppm by vol
Vinyl chloride			00075-01-4	<0.001	--	<0.01	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	0.003	--	0.01	--	A		ppm by vol
CO2e				2938.60	--	12871.09	--	A		ppm by vol

State of LouGsGana
EmGssGons Gnventory QuestGonnaGre (EGQ) for AGr Pollutants

Date of submGttal: Apr 2023

EmGssGon PoGnt GD No. (DesGgnatGon)	DescrGptGve Name of the EmGssGons Source (Alt. Name)	ApproxGmate LocatGon of Stack or Vent (see GnstructGons)
NGGEN1	Natural Gas Generator #1	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499556.10 mE Vertical: 3145223.00 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.67 ft	114.40 ft	125.98 ft/sec	2,638.61 ft^3/min	924 °F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Fuel — Type of Fuel Used and Heat Input (see instructions)

	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	18.18
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	17,820	scf/hr
Maximum Operating Rate/Throughput	17,820	scf/hr
Design Capacity/Volume/Cylinder Displacement	2,328	HP
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered: Engine Model Year:

Date Engine Was Built by Manufacturer:

SI Engines: ☐ Rich Burn ☑ Lean Burn ☐ 2 Stroke ☑ 4 Stroke

EmGssGon PoGnt GD No. (DesGgnatGon): NGGEN1 — Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates: Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Permitted Emission Rate (Current): Annual (tons/yr)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Particulate matter (PM_{10})				--	0.18	--	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				--	0.18	--	--	A		gr/std ft^3
Sulfur dioxide				--	0.01	--	--	A		ppm by vol
Nitrogen oxides				--	2.57	--	--	A		ppm by vol
Carbon monoxide				--	1.18	--	--	A		ppm by vol
Total VOC (including those listed below)				--	1.44	--	--	A		ppm by vol
Sulfuric Acid			07664-93-9	--	<0.001	--	--	A		ppm by vol

EmGssGon PoGnt GD No. (DesGgnatGon) NGGEN1 Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Acetaldehyde			00075-07-0	--	0.15	--	--	A		ppm by vol
Acrolein			00107-02-8	--	0.09	--	--	A		ppm by vol
Benzene			00071-43-2	--	0.01	--	--	A		ppm by vol
Biphenyl			00092-52-4	--	0.004	--	--	A		ppm by vol
1,3-Butadiene			00106-99-0	--	0.005	--	--	A		ppm by vol
Carbon tetrachloride			00056-23-5	--	<0.001	--	--	A		ppm by vol
Chlorobenzene			00108-90-7	--	<0.001	--	--	A		ppm by vol
Chloroform			00067-66-3	--	<0.001	--	--	A		ppm by vol
1,3-Dichloropropene			00542-75-6	--	<0.001	--	--	A		ppm by vol
Ethyl benzene			00100-41-4	--	<0.001	--	--	A		ppm by vol
1,2-Dibromoethane			00106-93-4	--	<0.001	--	--	A		ppm by vol
Formaldehyde			00050-00-0	--	0.61	--	--	A		ppm by vol
Methanol			00067-56-1	--	0.05	--	--	A		ppm by vol
Dichloromethane			00075-09-2	--	<0.001	--	--	A		ppm by vol
2-Methylnaphthalene			00091-57-6	--	<0.001	--	--	A		ppm by vol
n-Hexane			00110-54-3	--	0.02	--	--	A		ppm by vol
Naphthalene			00091-20-3	--	0.001	--	--	A		ppm by vol
Polynuclear Aromatic Hydrocarbons				--	<0.001	--	--	A		ppm by vol
Phenanthrene				--	<0.001	--	--	A		ppm by vol
Phenol			00108-95-2	--	<0.001	--	--	A		ppm by vol
Styrene			00100-42-5	--	<0.001	--	--	A		ppm by vol
Toluene			00108-88-3	--	0.01	--	--	A		ppm by vol
1,1,2,2-Tetrachloroethane			00079-34-5	--	<0.001	--	--	A		ppm by vol
1,1,2-Trichloroethane			00079-00-5	--	<0.001	--	--	A		ppm by vol
2,2,4-Trimethylpentane			00540-84-1	--	0.005	--	--	A		ppm by vol
Vinyl chloride			00075-01-4	--	<0.001	--	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	--	0.003	--	--	A		ppm by vol
CO2e				--	2938.60	--	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
NGGEN2	Natural Gas Generator #2	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499556.10 mE Vertical: 3145223.00 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.67 ft	114.40 ft	125.98 ft/sec	2,638.61 ft^3/min	924 °F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a	Natural Gas	18.18
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	17,820	scf/hr
Maximum Operating Rate/Throughput	17,820	scf/hr
Design Capacity/Volume/Cylinder Displacement	2,328	HP
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof Floating Roof ☐ External ☐ Internal

Date Engine Ordered | Engine Model Year

Date Engine Was Built by Manufacturer

SI Engines: ☐ **Rich Burn** ☑ **Lean Burn** ☐ **2 Stroke** ☑ **4 Stroke**

Emission Point ID No. (Designation): NGGEN2	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				--	0.18	--	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				--	0.18	--	--	A		gr/std ft^3
Sulfur dioxide				--	0.01	--	--	A		ppm by vol
Nitrogen oxides				--	2.57	--	--	A		ppm by vol
Carbon monoxide				--	1.18	--	--	A		ppm by vol
Total VOC (including those listed below)				--	1.44	--	--	A		ppm by vol
Sulfuric Acid			07664-93-9	--	<0.001	--	--	A		ppm by vol

Emission Point ID No. (Designation) NGGEN2 Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Acetaldehyde			00075-07-0	--	0.15	--	--	A		ppm by vol
Acrolein			00107-02-8	--	0.09	--	--	A		ppm by vol
Benzene			00071-43-2	--	0.01	--	--	A		ppm by vol
Biphenyl			00092-52-4	--	0.004	--	--	A		ppm by vol
1,3-Butadiene			00106-99-0	--	0.005	--	--	A		ppm by vol
Carbon tetrachloride			00056-23-5	--	<0.001	--	--	A		ppm by vol
Chlorobenzene			00108-90-7	--	<0.001	--	--	A		ppm by vol
Chloroform			00067-66-3	--	<0.001	--	--	A		ppm by vol
1,3-Dichloropropene			00542-75-6	--	<0.001	--	--	A		ppm by vol
Ethyl benzene			00100-41-4	--	<0.001	--	--	A		ppm by vol
1,2-Dibromoethane			00106-93-4	--	<0.001	--	--	A		ppm by vol
Formaldehyde			00050-00-0	--	0.61	--	--	A		ppm by vol
Methanol			00067-56-1	--	0.05	--	--	A		ppm by vol
Dichloromethane			00075-09-2	--	<0.001	--	--	A		ppm by vol
2-Methylnaphthalene			00091-57-6	--	<0.001	--	--	A		ppm by vol
n-Hexane			00110-54-3	--	0.02	--	--	A		ppm by vol
Naphthalene			00091-20-3	--	0.001	--	--	A		ppm by vol
Polynuclear Aromatic Hydrocarbons				--	<0.001	--	--	A		ppm by vol
Phenanthrene				--	<0.001	--	--	A		ppm by vol
Phenol			00108-95-2	--	<0.001	--	--	A		ppm by vol
Styrene			00100-42-5	--	<0.001	--	--	A		ppm by vol
Toluene			00108-88-3	--	0.01	--	--	A		ppm by vol
1,1,2,2-Tetrachloroethane			00079-34-5	--	<0.001	--	--	A		ppm by vol
1,1,2-Trichloroethane			00079-00-5	--	<0.001	--	--	A		ppm by vol
2,2,4-Trimethylpentane			00540-84-1	--	0.005	--	--	A		ppm by vol
Vinyl chloride			00075-01-4	--	<0.001	--	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	--	0.003	--	--	A		ppm by vol
CO2e				--	2938.60	--	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
DGEN	Emergency Diesel Generator	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499572.20 mE Vertical: 3145228.90 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.67 ft	104.40 ft	103.00 ft/sec	2,157.20 ft^3/min	757 °F	100 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a	Diesel	3.15
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	315.00	MMBtu/yr
Maximum Operating Rate/Throughput	3.15	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement	450	hp
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered: Engine Model Year:

Date Engine Was Built by Manufacturer:

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): DGEN	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				0.17	0.17	0.01	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				0.17	0.17	0.01	--	A		gr/std ft^3
Sulfur dioxide				0.32	0.32	0.02	--	A		ppm by vol
Nitrogen oxides				2.96	2.96	0.15	--	A		ppm by vol
Carbon monoxide				2.59	2.59	0.13	--	A		ppm by vol
Total VOC (including those listed below)				2.96	2.96	0.15	--	A		ppm by vol

Emission Point ID No. (Designation) DGEN	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				**Average (lb/hr)**	**Maximum (lbs/hr)**	**Annual (tons/yr)**	**Annual (tons/yr)**			
Sulfuric Acid			07664-93-9	0.01	0.01	<0.001	--	A		ppm by vol
CO2e				515.38	515.38	25.77	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
BCRANE1	Platform B Crane #1	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499539.50 mE Vertical: 3145195.80 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.33 ft	154.67 ft	97.27 ft/sec	509.28 ft^3/min	980 °F	4,380 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a	Diesel	3.33
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	14,564	MMBtu/yr
Maximum Operating Rate/Throughput	3.33	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement	475	hp
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered | Engine Model Year

Date Engine Was Built by Manufacturer

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): BCRANE1	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				0.05	0.05	0.11	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				0.05	0.05	0.11	--	A		gr/std ft^3
Sulfur dioxide				0.34	0.34	0.74	--	A		ppm by vol
Nitrogen oxides				0.47	0.47	1.03	--	A		ppm by vol
Carbon monoxide				2.73	2.73	5.99	--	A		ppm by vol
Total VOC (including those listed below)				0.22	0.22	0.49	--	A		ppm by vol

Emission Point ID No. (Designation) BCRANE1 Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Sulfuric Acid			07664-93-9	0.01	0.01	0.02	--	A		ppm by vol
Acetaldehyde			00075-07-0	0.003	0.003	0.01	--	A		ppm by vol
Acrolein			00107-02-8	<0.001	<0.001	<0.01	--	A		ppm by vol
Benzene			00071-43-2	0.003	0.003	0.01	--	A		ppm by vol
Formaldehyde			00050-00-0	0.004	0.004	0.01	--	A		ppm by vol
Toluene			00108-88-3	0.001	0.001	<0.01	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	<0.001	<0.001	<0.01	--	A		ppm by vol
Polynuclear Aromatic Hydrocarbons				<0.001	<0.001	<0.01	--	A		ppm by vol
CO2e				544.01	544.01	1191.39	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
BCRANE2	Platform B Crane #2	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499573.90 mE Vertical: 3145230.20 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.33 ft	154.67 ft	97.27 ft/sec	509.28 ft^3/min	980 °F	4,380 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a	Diesel	3.33
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	14,564	MMBtu/yr
Maximum Operating Rate/Throughput	3.33	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement	475	hp
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered | Engine Model Year

Date Engine Was Built by Manufacturer

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): BCRANE2	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				0.05	0.05	0.11	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				0.05	0.05	0.11	--	A		gr/std ft^3
Sulfur dioxide				0.34	0.34	0.74	--	A		ppm by vol
Nitrogen oxides				0.47	0.47	1.03	--	A		ppm by vol
Carbon monoxide				2.73	2.73	5.99	--	A		ppm by vol
Total VOC (including those listed below)				0.22	0.22	0.49	--	A		ppm by vol

Emission Point ID No. (Designation) BCRANE2	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				**Average (lb/hr)**	**Maximum (lbs/hr)**	**Annual (tons/yr)**	**Annual (tons/yr)**			
Sulfuric Acid			07664-93-9	0.01	0.01	0.02	--	A		ppm by vol
Acetaldehyde			00075-07-0	0.003	0.003	0.01	--	A		ppm by vol
Acrolein			00107-02-8	<0.001	<0.001	<0.01	--	A		ppm by vol
Benzene			00071-43-2	0.003	0.003	0.01	--	A		ppm by vol
Formaldehyde			00050-00-0	0.004	0.004	0.01	--	A		ppm by vol
Toluene			00108-88-3	0.001	0.001	<0.01	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	<0.001	<0.001	<0.01	--	A		ppm by vol
Polynuclear Aromatic Hydrocarbons				<0.001	<0.001	<0.01	--	A		ppm by vol
CO2e				544.01	544.01	1191.39	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
BFWP	Platform B Firewater Pump	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499552.80 mE Vertical: 3145247.80 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.33 ft	56.16 ft	133.10 ft/sec	696.91 ft^3/min	980 °F	100 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Fuel — Type of Fuel Used and Heat Input (see instructions)

	Type of Fuel	Heat Input (MMBTU/hr)
a	Diesel	4.55
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	455	MMBtu/yr
Maximum Operating Rate/Throughput	4.55	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement	650	HP
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof Floating Roof ☐ External ☐ Internal

Date Engine Ordered | Engine Model Year

Date Engine Was Built by Manufacturer

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): BFWP	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				0.25	0.25	0.01	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				0.25	0.25	0.01	--	A		gr/std ft^3
Sulfur dioxide				0.46	0.46	0.02	--	A		ppm by vol
Nitrogen oxides				4.30	4.30	0.21	--	A		ppm by vol
Carbon monoxide				3.73	3.73	0.19	--	A		ppm by vol
Total VOC (including those listed below)				4.30	4.30	0.21	--	A		ppm by vol

Emission Point ID No. (Designation) BFWP Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Sulfuric Acid			07664-93-9	0.01	0.01	<0.001	--	A		ppm by vol
CO2e				744.44	744.44	37.22	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
CFWP	Platform C Firewater Pump	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499507.67 mE Vertical: 3145358.27 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.33 ft	56.06 ft	133.10 ft/sec	696.91 ft^3/min	980 °F	100 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Fuel — Type of Fuel Used and Heat Input (see instructions)

	Type of Fuel	Heat Input (MMBTU/hr)
a	Diesel	4.55
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	455	MMBtu/yr
Maximum Operating Rate/Throughput	4.55	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement	650	HP
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof Floating Roof ☐ External ☐ Internal

Date Engine Ordered | Engine Model Year

Date Engine Was Built by Manufacturer

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): CFWP	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				0.25	0.25	0.01	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				0.25	0.25	0.01	--	A		gr/std ft^3
Sulfur dioxide				0.46	0.46	0.02	--	A		ppm by vol
Nitrogen oxides				4.30	4.30	0.21	--	A		ppm by vol
Carbon monoxide				3.73	3.73	0.19	--	A		ppm by vol
Total VOC (including those listed below)				4.30	4.30	0.21	--	A		ppm by vol

Emission Point ID No. (Designation) CFWP Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Sulfuric Acid			07664-93-9	0.01	0.01	<0.001	--	A		ppm by vol
CO2e				744.44	744.44	37.22	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
PDST	Primary Diesel Storage Tank	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499557.40 mE Vertical: 3145253.30 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.50 ft	102.40 ft	3.28 ft/sec	38.65 ft^3/min	77 °F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a		
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	468,000	gal/yr
Maximum Operating Rate/Throughput	400	gal/hr
Design Capacity/Volume/Cylinder Displacement	18,000	gal
Shell Height (ft)	10.00	ft
Tank Diameter (ft)	17.76	ft

Tanks: ☑ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered: Engine Model Year:

Date Engine Was Built by Manufacturer:

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation)	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
PDST										
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Total VOC (including those listed below)				0.002	--	0.01	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	<0.001	--	<0.001	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
SRGT	Surge Tank	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499527.30 mE Vertical: 3145190.30 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	0.50 ft	105.06 ft	3.28 ft/sec	38.65 ft^3/min	150 °F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a		
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	42,000	gal/yr
Maximum Operating Rate/Throughput	80,000	gal/hr
Design Capacity/Volume/Cylinder Displacement	42,000	gal
Shell Height (ft)	47.50	ft
Tank Diameter (ft)	12.67	ft

Tanks: ☑ Fixed Roof ☐ Floating Roof ☐ External ☐ Internal

Date Engine Ordered		Engine Model Year	
Date Engine Was Built by Manufacturer			

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): SRGT	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Total VOC (including those listed below)				0.85	--	3.73	--	A		ppm by vol
Benzo(g,h,i)perylene				0.004	--	0.02	--	A		ppm by vol
Cyclohexane				0.005	--	0.02	--	A		ppm by vol
Ethylcyclohexane				<0.001	--	<0.01	--	A		ppm by vol

Emission Point ID No. (Designation) SRGT Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Hexanol				0.004	--	0.02	--	A		ppm by vol
Toluene diisocyanate				0.002	--	0.01	--	A		ppm by vol
Xylene (mixed isomers)			01330-20-7	<0.001	--	<0.01	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
VCU1	VCU Stack 1	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499496.40 mE Vertical: 3145141.10 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	12.63 ft	136.00 ft	65.62 ft/sec	492,878.79 ft^3/min	600 °F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a	VLCC Vapors, Assist Natural Gas, Pilot Natural Gas	218.09
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	218.09	MMBtu/hr
Maximum Operating Rate/Throughput	218.09	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof Floating Roof ☐ External ☐ Internal

Date Engine Ordered			Engine Model Year	
Date Engine Was Built by Manufacturer				

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): VCU1	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				1.14	1.14	4.99	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				1.14	1.14	4.99	--	A		gr/std ft^3
Sulfur dioxide				40.02	40.02	4.25	--	A		ppm by vol
Nitrogen oxides				32.71	32.71	143.29	--	A		ppm by vol
Carbon monoxide				60.08	60.08	263.17	--	A		ppm by vol
Total VOC (including those listed below)				82.32	82.32	260.19	--	A		ppm by vol

Emission Point ID No. (Designation) VCU1 Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Hydrogen Sulfide				1.07	1.07	0.11	--	A		ppm by vol
Hexane			00110-54-3	3.37	3.37	10.64	--	A		ppm by vol
Benzene			00071-43-2	0.66	0.66	2.08	--	A		ppm by vol
Toluene			00108-88-3	0.29	0.29	0.92	--	A		ppm by vol
Ethyl benzene			00100-41-4	0.04	0.04	0.13	--	A		ppm by vol
1,2,4-Trimethylbenzene			95-63-6	0.01	0.01	0.03	--	A		ppm by vol
1,3-dimethylbenzene			108-38-3	0.04	0.04	0.12	--	A		ppm by vol
1,4-dimethylbenzene			106-42-3	0.03	0.03	0.09	--	A		ppm by vol
Xylene			01330-20-7	0.17	0.17	0.54	--	A		ppm by vol
Cumene			00098-82-8	0.005	0.005	0.02	--	A		ppm by vol
Cresol			01319-77-3	<0.001	<0.001	<0.01	--	A		ppm by vol
Naphthalene			00091-20-3	<0.001	<0.001	<0.01	--	A		ppm by vol
Phenol			00108-95-2	0.001	0.001	<0.01	--	A		ppm by vol
CO2e				35961.28	35961.28	157510.39	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
VCU2	VCU Stack 2	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499501.90 mE Vertical: 3145136.60 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	12.63 ft	136.00 ft	65.62 ft/sec	492,878.79 ft^3/min	600 °F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a	VLCC Vapors, Assist Natural Gas, Pilot Natural Gas	218.09
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	218.09	MMBtu/hr
Maximum Operating Rate/Throughput	218.09	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof Floating Roof ☐ External ☐ Internal

Date Engine Ordered			Engine Model Year	
Date Engine Was Built by Manufacturer				

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): VCU2	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				1.14	1.14	4.99	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				1.14	1.14	4.99	--	A		gr/std ft^3
Sulfur dioxide				40.02	40.02	4.25	--	A		ppm by vol
Nitrogen oxides				32.71	32.71	143.29	--	A		ppm by vol
Carbon monoxide				60.08	60.08	263.17	--	A		ppm by vol
Total VOC (including those listed below)				82.32	82.32	260.19	--	A		ppm by vol

Emission Point ID No. (Designation) VCU2 Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Hydrogen Sulfide				1.07	1.07	0.11	--	A		ppm by vol
Hexane			00110-54-3	3.37	3.37	10.64	--	A		ppm by vol
Benzene			00071-43-2	0.66	0.66	2.08	--	A		ppm by vol
Toluene			00108-88-3	0.29	0.29	0.92	--	A		ppm by vol
Ethyl benzene			00100-41-4	0.04	0.04	0.13	--	A		ppm by vol
1,2,4-Trimethylbenzene			95-63-6	0.01	0.01	0.03	--	A		ppm by vol
1,3-dimethylbenzene			108-38-3	0.04	0.04	0.12	--	A		ppm by vol
1,4-dimethylbenzene			106-42-3	0.03	0.03	0.09	--	A		ppm by vol
Xylene			01330-20-7	0.17	0.17	0.54	--	A		ppm by vol
Cumene			00098-82-8	0.005	0.005	0.02	--	A		ppm by vol
Cresol			01319-77-3	<0.001	<0.001	<0.01	--	A		ppm by vol
Naphthalene			00091-20-3	<0.001	<0.001	<0.01	--	A		ppm by vol
Phenol			00108-95-2	0.001	0.001	<0.01	--	A		ppm by vol
CO2e				35961.28	35961.28	157510.39	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
VCU3	VCU Stack 3	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499507.50 mE Vertical: 3145132.10 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	12.63 ft	136.00 ft	65.62 ft/sec	492,878.79 ft^3/min	600 °F	8,760 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a	VLCC Vapors, Assist Natural Gas, Pilot Natural Gas	218.09
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	218.09	MMBtu/hr
Maximum Operating Rate/Throughput	218.09	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof Floating Roof ☐ External ☐ Internal

Date Engine Ordered			Engine Model Year	
Date Engine Was Built by Manufacturer				

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): VCU3	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Particulate matter (PM_{10})				1.14	1.14	4.99	--	A		gr/std ft^3
Particulate matter ($PM_{2.5}$)				1.14	1.14	4.99	--	A		gr/std ft^3
Sulfur dioxide				40.02	40.02	4.25	--	A		ppm by vol
Nitrogen oxides				32.71	32.71	143.29	--	A		ppm by vol
Carbon monoxide				60.08	60.08	263.17	--	A		ppm by vol
Total VOC (including those listed below)				82.32	82.32	260.19	--	A		ppm by vol

Emission Point ID No. (Designation) VCU3	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				**Average (lb/hr)**	**Maximum (lbs/hr)**	**Annual (tons/yr)**	**Annual (tons/yr)**			
Hydrogen Sulfide				1.07	1.07	0.11	--	A		ppm by vol
Hexane			00110-54-3	3.37	3.37	10.64	--	A		ppm by vol
Benzene			00071-43-2	0.66	0.66	2.08	--	A		ppm by vol
Toluene			00108-88-3	0.29	0.29	0.92	--	A		ppm by vol
Ethyl benzene			00100-41-4	0.04	0.04	0.13	--	A		ppm by vol
1,2,4-Trimethylbenzene			95-63-6	0.01	0.01	0.03	--	A		ppm by vol
1,3-dimethylbenzene			108-38-3	0.04	0.04	0.12	--	A		ppm by vol
1,4-dimethylbenzene			106-42-3	0.03	0.03	0.09	--	A		ppm by vol
Xylene			01330-20-7	0.17	0.17	0.54	--	A		ppm by vol
Cumene			00098-82-8	0.005	0.005	0.02	--	A		ppm by vol
Cresol			01319-77-3	<0.001	<0.001	<0.01	--	A		ppm by vol
Naphthalene			00091-20-3	<0.001	<0.001	<0.01	--	A		ppm by vol
Phenol			00108-95-2	0.001	0.001	<0.01	--	A		ppm by vol
CO2e				35961.28	35961.28	157510.39	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
LPFL	Low Pressure Flare - Vapor Capture	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499806.40 mE Vertical: 3145265.90 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	8.39 ft	186.00 ft	65.62 ft/sec	217,498.03 ft^3/min	1832 °F	275 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Type of Fuel Used and Heat Input (see instructions)

Fuel		Type of Fuel	Heat Input (MMBTU/hr)
	a	VLCC Vapors and Pilot Natural Gas	212.38
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	212.38	MMBtu/hr
Maximum Operating Rate/Throughput	212.38	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof Floating Roof ☐ External ☐ Internal

Date Engine Ordered			Engine Model Year	
Date Engine Was Built by Manufacturer				

SI Engines: ☐ **Rich Burn** ☐ **Lean Burn** ☐ **2 Stroke** ☐ **4 Stroke**

Emission Point ID No. (Designation): LPFL	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
NOx				29.31	29.31	4.03	--	A		ppm by vol
CO				58.51	58.51	8.05	--	A		ppm by vol
SO2				13.78	13.78	0.32	--	A		ppm by vol
VOC				384.78	384.78	52.91	--	A		ppm by vol
Hexane			00110-54-3	15.74	15.74	2.16	--	A		ppm by vol
Benzene			00071-43-2	3.08	3.08	0.42	--	A		ppm by vol
Toluene			00108-88-3	1.37	1.37	0.19	--	A		ppm by vol

Emission Point ID No. (Designation) LPFL Pollutant	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Ethyl benzene			00100-41-4	0.19	0.19	0.03	--	A		ppm by vol
1,2,4-Trimethylbenzene			95-63-6	0.04	0.04	0.01	--	A		ppm by vol
1,3-Dimethylbenzene			108-38-3	0.18	0.18	0.03	--	A		ppm by vol
1,4-Dimethylbenzene			106-42-3	0.13	0.13	0.02	--	A		ppm by vol
1,2-Dimethylbenzene			95-47-6	0.80	0.80	0.11	--	A		ppm by vol
Cumene			00098-82-8	0.02	0.02	<0.01	--	A		ppm by vol
CO2e				35019.51	35019.51	4815.18	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
HPFL	High Pressure Flare - Natural Gas	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499806.4 mE Vertical: 3145265.9 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	21.22 ft	186.00 ft	65.62 ft/sec	1,392,783.00 ft^3/min	1,832 °F	11 hr/yr	proposed	25%	25%	25%	25%
	ft^2										

Fuel — Type of Fuel Used and Heat Input (see instructions)

	Type of Fuel	Heat Input (MMBTU/hr)
a	Natural Gas	1,360
b		
c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput	1,360	MMBtu/hr
Maximum Operating Rate/Throughput	1,360	MMBtu/hr
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof Floating Roof ☐ External ☐ Internal

Date Engine Ordered			Engine Model Year	
Date Engine Was Built by Manufacturer				

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): HPFL	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
NOx				187.68	187.68	1.03	--	A		gr/std ft^3
CO				374.68	374.68	2.06	--	A		ppm by vol
SO2				0.23	0.23	<0.01	--	A		ppm by vol
VOC				24.85	24.85	0.14	--	A		ppm by vol
Hexane			00110-54-3	2.43	2.43	0.01	--	A		ppm by vol
CO2e				161048.37	161048.37	885.77	--	A		ppm by vol

State of Louisiana
Emissions Inventory Questionnaire (EIQ) for Air Pollutants

Date of submittal: Apr 2023

Emission Point ID No. (Designation)	Descriptive Name of the Emissions Source (Alt. Name)	Approximate Location of Stack or Vent (see instructions)
FUG	Facility Wide Fugitives	Method: 18,"Interpolation - Map" Datum: WGS84
Tempo Subject Item ID No.		UTM Zone: 15 Horizontal: 499554.70 mE Vertical: 3145251.00 mN
		Latitude: ° ' " hundredths
		Longitude: ° ' " hundredths

Stack and Discharge Physical Characteristics Change? (yes or no)	Diameter (ft) or Stack Discharge Area (ft^2)	Height of Stack Above Grade (ft)	Stack Gas Exit Velocity	Stack Gas Flow at Conditions, not at Standard (ft^3/min)	Stack Gas Exit Temperature (°F)	Normal Operating Time (hours per year)	Date of Construction or Modification	Percent of Annual Throughput Through This Emission Point			
								Jan-Mar	Apr-Jun	Jul-Sep	Oct-Dec
yes	N/A ft ft^2	N/A ft	N/A ft/sec	ft^3/min	N/A °F	8760 hr/yr	proposed	25%	25%	25%	25%

Fuel — Type of Fuel Used and Heat Input (see instructions)

		Type of Fuel	Heat Input (MMBTU/hr)
Fuel	a		
	b		
	c		

Notes

Operating Parameters (include units)

	Parameter	Description
Normal Operating Rate/Throughput		
Maximum Operating Rate/Throughput		
Design Capacity/Volume/Cylinder Displacement		
Shell Height (ft)		
Tank Diameter (ft)		

Tanks: ☐ Fixed Roof Floating Roof ☐ External ☐ Internal

Date Engine Ordered			Engine Model Year	
Date Engine Was Built by Manufacturer				

SI Engines: ☐ Rich Burn ☐ Lean Burn ☐ 2 Stroke ☐ 4 Stroke

Emission Point ID No. (Designation): FUG	Control Equipment Code	Control Equipment Efficiency	HAP / TAP CAS Number	Proposed Emission Rates			Permitted Emission Rate (Current)	Add, Change, Delete, or Unchanged	Continuous Compliance Method	Concentration in Gases Exiting at Stack
Pollutant				Average (lb/hr)	Maximum (lbs/hr)	Annual (tons/yr)	Annual (tons/yr)			
Total VOC (including those listed below)				5.41	5.41	23.69	--	A		ppm by vol
Hydrogen Sulfide			07783-06-4	0.001	0.001	0.01	--	A		ppm by vol
CO2e				276.45	276.45	1210.83	--	A		ppm by vol

24. NSR Applicability Summary [LAC 33:III.504 and LAC 33:III.509] ☐ N/A

Refer to Sections 4 the Prevention of Significant Deterioration Air Construction Permit Application Volume 1 for the NSR Applicability Summary.

This section consists of seven subsections, A-G, and is applicable only to new and existing major stationary sources (as defined in LAC 33:III.504 or in LAC 33:III.509) proposing to permit a physical change or change in the method of operation. It would also apply to existing minor stationary sources proposing a physical change or change in the method of operation where the change would be a major source in and of itself. Add rows to each table as necessary. Provide a written explanation of the information summarized in these tables. Consult instructions.

24.A. Project Summary

		A	B	C	D	E	F
Emission Point ID	**Description**	**New, Modified, Affected, or Unaffected***	**Pre-Project Allowables (TPY)**	**Baseline Actual Emissions (over 24-month period)**	**Projected Actual Emissions (TPY)**	**Post-Project Potential to Emit (TPY)**	**Change**
$PM_{2.5}$	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	--	--
	VCU Stack #1	NEW	N/A	N/A	N/A	4.99	4.99
	VCU Stack #2	NEW	N/A	N/A	N/A	4.99	4.99
	VCU Stack #3	NEW	N/A	N/A	N/A	4.99	4.99
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	--	--
	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	--	--
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	0.80	0.80
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	8.61E-03	8.61E-03
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	0.21	0.21
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	0.01	0.01
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	0.01	0.01

	Primary Diesel Tank	NEW	N/A	N/A	N/A	--	--
	Surge Tank	NEW	N/A	N/A	N/A	--	--
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	--	--
						16.00	**16.00**
						$PM_{2.5}$ Change:	**16.00**

PM_{10}	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	--	--
	VCU Stack #1	NEW	N/A	N/A	N/A	4.99	4.99
	VCU Stack #2	NEW	N/A	N/A	N/A	4.99	4.99
	VCU Stack #3	NEW	N/A	N/A	N/A	4.99	4.99
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	--	--
	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	--	--
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	0.80	0.80
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	8.61E-03	8.61E-03
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	0.21	0.21
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	0.01	0.01
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	0.01	0.01
	Primary Diesel Tank	NEW	N/A	N/A	N/A	--	--
	Surge Tank	NEW	N/A	N/A	N/A	--	--
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	--	--
						16.00	**16.00**
						PM_{10} Change:	**16.00**

SO_2	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	--	--
	VCU Stack #1	NEW	N/A	N/A	N/A	4.25	4.25
	VCU Stack #2	NEW	N/A	N/A	N/A	4.25	4.25
	VCU Stack #3	NEW	N/A	N/A	N/A	4.25	4.25
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	0.32	0.32
	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	1.24E-03	1.24E-03
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	0.05	0.05
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	0.02	0.02
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	1.48	1.48
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	0.02	0.02
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	0.02	0.02
	Primary Diesel Tank	NEW	N/A	N/A	N/A	--	--
	Surge Tank	NEW	N/A	N/A	N/A	--	--
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	--	--
						14.66	**14.66**
						SO_2 Change:	**14.66**

NO_X	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	--	--
	VCU Stack #1	NEW	N/A	N/A	N/A	143.29	143.29
	VCU Stack #2	NEW	N/A	N/A	N/A	143.29	143.29

	VCU Stack #3	NEW	N/A	N/A	N/A	143.29	143.29
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	4.03	4.03
	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	1.03	1.03
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	11.24	11.24
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	0.15	0.15
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	2.05	2.05
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	0.21	0.21
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	0.21	0.21
	Primary Diesel Tank	NEW	N/A	N/A	N/A	--	--
	Surge Tank	NEW	N/A	N/A	N/A	--	--
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	--	--
						448.79	**448.79**
						NO_X Change:	**448.79**

CO	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	--	--
	VCU Stack #1	NEW	N/A	N/A	N/A	263.17	263.17
	VCU Stack #2	NEW	N/A	N/A	N/A	263.17	263.17
	VCU Stack #3	NEW	N/A	N/A	N/A	263.17	263.17
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	8.05	8.05

	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	2.06	2.06
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	5.17	5.17
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	0.13	0.13
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	11.97	11.97
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	0.19	0.19
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	0.19	0.19
	Primary Diesel Tank	NEW	N/A	N/A	N/A	--	--
	Surge Tank	NEW	N/A	N/A	N/A	--	--
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	--	--
						817.25	**817.25**
						CO Change:	**817.25**

VOC	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	1,604.05	1,604.05
	VCU Stack #1	NEW	N/A	N/A	N/A	260.19	260.19
	VCU Stack #2	NEW	N/A	N/A	N/A	260.19	260.19
	VCU Stack #3	NEW	N/A	N/A	N/A	260.19	260.19
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	52.91	52.91

	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	0.14	0.14
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	6.29	6.29
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	0.15	0.15
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	0.97	0.97
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	0.21	0.21
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	0.21	0.21
	Primary Diesel Tank	NEW	N/A	N/A	N/A	8.51E-03	8.51E-03
	Surge Tank	NEW	N/A	N/A	N/A	3.73	3.73
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	23.69	23.69
						2,472.97	**2,472.97**
						VOC Change:	**2,472.97**

CO_2e	**24-Month Period:** N/A – NEW FACILTY						
	Uncaptured Loading	NEW	N/A	N/A	N/A	--	--
	VCU Stack #1	NEW	N/A	N/A	N/A	157,510	157,510
	VCU Stack #2	NEW	N/A	N/A	N/A	157,510	157,510
	VCU Stack #3	NEW	N/A	N/A	N/A	157,510	157,510
	Vapor Capture - Low Pressure Flare	NEW	N/A	N/A	N/A	4,815	4,815

	Natural Gas - High Pressure Flare	NEW	N/A	N/A	N/A	886	886
	Power Generation - Natural Gas Engines (x2)	NEW	N/A	N/A	N/A	12,871	12,871
	Emergency Diesel Generator	NEW	N/A	N/A	N/A	25.77	25.77
	Platform B Cranes (x2)	NEW	N/A	N/A	N/A	2,383	2,383
	Platform B Firewater Pump Engine	NEW	N/A	N/A	N/A	37.22	37.22
	Platform C Firewater Pump Engine	NEW	N/A	N/A	N/A	37.22	37.22
	Primary Diesel Tank	NEW	N/A	N/A	N/A	--	--
	Surge Tank	NEW	N/A	N/A	N/A	--	--
	Facility Wide Fugitives	NEW	N/A	N/A	N/A	1,211	1,211
						494,797	**494,797**
						CO_2e Change:	**494,797**

* Unaffected emissions units are not required to be listed individually. By choosing not to list unaffected emissions units, the applicant asserts that all emissions units not listed in Table 24.A will not be modified or experience an increase in actual annual emissions as part of the proposed project.

24.B. Creditable Contemporaneous Changes

Contemporaneous Period: MM/DD/YYYY – MM/DD/YYYY	

		A	B	C	D	E	F
Emission Point ID	**Description**	**Date of Modification**	**Pre-Project Allowables (TPY)**	**Baseline Actual Emissions (over 24-month period)**	**24-Month Period**	**Post-Project Potential to Emit (TPY)**	**Change**
$PM_{2.5}$							

24.B. Creditable Contemporaneous Changes

						$PM_{2.5}$ Change:	
PM_{10}							
						PM_{10} Change:	
SO_2							
						SO_2 Change:	
NO_X							
						NO_X Change:	
CO							
						CO Change:	
VOC							
						VOC Change:	
CO_2e							

24.B. Creditable Contemporaneous Changes

						CO_2e Change:	

For each source identified as "New" or "Modified" in Section 24.A, complete the following table for each pollutant that will trigger NSR. If LAER is not required per LAC 33:III.504.D.3, indicate such.

24.C. BACT/LAER Summary

Refer to Section 5 of the Prevention of Significant Deterioration Air Construction Permit Application Volume 1 for the BACT analysis.

Emission Point ID	Pollutant	BACT/LAER	Limitation	Averaging Period	Description of Control Technology/Work Practice Standard(s)

24.D. PSD Air Quality Analyses Summary – Refer to the PSD Air Construction Permit Application Volume 2

		A	B	C	D	E	F	G	H	I
Pollutant	Averaging Period	Preliminary Screening Concentration (µg/m³)	Level of Significant Impact (µg/m³)	Significant Monitoring Concentration (µg/m³)	Background (µg/m³)	Maximum Modeled Concentration (µg/m³)	Modeled + Background Concentration (µg/m³)	NAAQS (µg/m³)	Modeled PSD Increment Consumption (µg/m³)	Allowable Class II PSD Increment (µg/m³)
$PM_{2.5}$	24-hour		-	-				35		9
	Annual		-	-				12		4
PM_{10}	24-hour		5	10				150		30
	Annual		1	-				-		17
SO_2	1-hour		7.8	-				195		-
	3-hour		25	-				1300		512
	24-hour		5	13				365		91
	Annual		1	-				80		20
NO_X	1-hour		7.5	-				189		-
	Annual		1	14				100		25
CO	1-hour		2000	-				40,000	-	-
	8-hour		500	575				10,000	-	-
Lead	3-month		-	0.1				1.5	-	-

24.E Nonattainment New Source Review Offsets [LAC 33:III.517.D.16, LAC 33:III.504.D.4 & 5] ☒ **N/A**

Complete this section only if the proposed project triggers Nonattainment New Source Review (NNSR).

This project triggers NNSR review for: ☐ **NO_X** ☐ **VOC** ☐ **SO_2**

NO_X:

Is the applicant proposing to use internal offsets? ☐ **Yes** ☐ **No**

If not, identify the source of the offsets. **Company:** _____

Facility/Unit: _____

Permit No.: _____

Is an ERC Bank Application included with this application, or has an application already been submitted to LDEQ?

☐ **Yes** ☐ **No**

If the ERC application has already been submitted, give the date: _____

Identify the emissions units from which the offsets will be obtained (reference specific Emission Point ID numbers).

VOC:

Is the applicant proposing to use internal offsets? ☐ **Yes** ☐ **No**

If not, identify the source of the offsets. **Company:** _____

Facility/Unit: _____

Permit No.: _____

Is an ERC Bank Application included with this application, or has an application already been submitted to LDEQ?

☐ **Yes** ☐ **No**

If the ERC application has already been submitted, give the date: _____

Identify the emissions units from which the offsets will be obtained (reference specific Emission Point ID numbers).

SO_2:

Is the applicant proposing to use internal offsets? ☐ **Yes** ☐ **No**

If not, identify the source of the offsets. **Company:** _____

Facility/Unit: _____

Permit No.: _____

Is an ERC Bank Application included with this application, or has an application already been submitted to LDEQ?

☐ **Yes** ☐ **No**

If the ERC application has already been submitted, give the date: _____

Identify the emissions units from which the offsets will be obtained (reference specific Emission Point ID numbers).

In order to expedite processing, please be sure the ERC Bank Application is completed properly. In the case of NO_X, the document should clearly differentiate between ozone season and non-ozone season actual emissions during the baseline period. Be sure to indicate if a portion of the reductions are no longer surplus (e.g., due to new or revised federal or state regulations, use in a netting analysis, etc.).

24.F. Economic Impact

Answer the following questions.

How many temporary jobs will be added as a result of this project? 1393

How many permanent jobs will be added as a result of this project? 140

24.G Notification of Federal Land Manager [LAC 33:III.504.E.1, LAC 33:III.509.P.1]
Complete this section only if the proposed project triggers NNSR or PSD.

a. Is the proposed facility or modification located within 100 kilometers of a Class I Area? ☐ **Yes** ☒ **No**
If Yes, determination of Q/d is not required; skip to the next question. If No, complete the Q/d equation below:

$$Q/d = \frac{PM_{10\,(NEI)} + SO_{2\,(NEI)} + NO_{X\,(NEI)} + H_2SO_{4\,(NEI)}}{\text{Class I km}}$$

where:
- $PM_{10\,(NEI)}$ = net emissions increase of PM_{10}[1,2]
- $SO_{2\,(NEI)}$ = net emissions increase of SO_2[1,2]
- $NO_{X\,(NEI)}$ = net emissions increase of NO_X[1,2]
- $H_2SO_{4\,(NEI)}$ = net emissions increase of H_2SO_4[1,2]
- Class I km = distance to nearest Class I Area[3]

$$Q/d = \frac{_____ + _____ + _____ + _____}{_____} = _____$$

Per Federal Land Manager guidance, Q values should reflect annual emissions (in tons per year, based on 24-hour maximum allowable emissions). If Q/d < 10, proceed to Section 25. If Q/d ≥ 10, complete the remainder of this Section.

b. Has the applicant provided a copy of the application to the Federal Land Manager? ☐ **Yes** ☒ **No**

c. Does the application contain modeling that demonstrates no adverse impact on Air Quality Related Values (AQRVs) in the Class I Area? ☐ **Yes** ☒ **No**

d. If Yes, indicate the model used: ☐ **VISCREEN** ☐ **PLUVUE II** ☐ **CALPUFF** ☐ **Other:**[4] _____

e. Has the Federal Land Manager concurred that the proposed project will not adversely impact any AQRVs?
☐ **Yes** ☒ **No** If Yes, please attach correspondence.

[1]If the net emissions increase of any pollutant is negative, enter "0."
[2]If the project did not trigger a netting analysis, use the project increase. In this case, the value will be less than the pollutant's significance level.
[3]In kilometers.
[4]Model must be approved by LDEQ and the Federal Land Manager.

25. Environmental Assessment Statement (EAS or "IT" Question Responses)

[La. R.S. 30:2018] ☒ **Yes** ☐ **No**

*** This section is required when applying for new Part 70 operating permits and/or major modifications. Any applications for these permit types that do not include answers to these questions will not be considered to be administratively complete. ***

For new Part 70 operating permits and/or major modifications, answers to these questions must be provided by the applicant to the local governmental authority and the designated public library at no additional costs to these entities. Consult instructions to determine what is considered to be a "local governmental authority" and a "designated public library." Indicate the name and address of the local governmental authority and the designated public library to which the answers to these questions were sent:

Name of Local Governing Authority			**Name of Designated Public Library**		
Street or P.O. Box			**Street or P.O. Box**		
City	**State**	**ZIP**	**City**	**State**	**ZIP**

Answer the following five questions on separate pages using full and complete answers. Include as many pages as necessary in order to provide full and complete answers. This information is required per Louisiana Revised Statutes 30:2018 (La. R.S. 30:2018).

Question 1: **Have the potential and real adverse environmental effects of the proposed facility been avoided to the maximum extent possible?**

Yes, Blue Marlin Offshore Port, LLC (BMOP) will avoid adverse environmental effects to the maximum extent possible as described below. Further information regarding the prevention and minimization of adverse impacts to the environment from the Project may be found in the environmental analysis being conducted concurrently on behalf of the Maritime Administration and U.S. Coast Guard (Docket number MARAD-2020-0127). EPA is serving as a cooperating agency to that environmental review process.

- **Environmental Effects to Air** – As described in the Title V Application for this facility, all new source emissions of air pollutants will be in compliance with applicable Federal and State regulations. A detailed Best Available Control Technology (BACT) analysis has been conducted, and control technologies will be implemented for Facility operation. Details (including Potential to Emit [PTE] calculations, Prevention of Significant Deterioration [PSD] analysis, and air dispersion modeling) for air emission sources can be found within this application.

- **Environmental Effects to Water** - During operation, the onshore pipeline facilities will be operated and maintained in accordance with PHMSA regulations provided in 49 CFR Part 195. BMOP will control operations from a remote location. The onshore pipeline will be monitored by a control center 24 hours per day, 7 days per week for pipeline flowrates, pressures, and operating conditions. A change in operating conditions, or in the event of an emergency, immediate communication will be made with the control center for response. The pipeline will also be monitored via aerial patrol, in accordance with 49 CFR Part 195.

BMOP will conduct maintenance pigging of the onshore pipelines on a monthly basis and will conduct inspections using smart pigs once every 5 years. Maintenance requirements and frequency of inspection for internal and external corrosion, among other factors, will be included in the Port Operation Manual.

BMOP's existing Spill Response Plan will be modified for operations in accordance with the Oil Pollution Act of 1990 and PHMSA's implementing regulations in 49 CFR Part 194, the National Oil and Hazardous Substances Pollution Contingency Plan, applicable Area Contingency Plans, the USEPA Region 6 Regional Integrated Contingency Plan, and

the One Gulf Plan. The plan has been developed to assist personnel with quickly, safely, and effectively responding to a crude oil spill either onshore or offshore and will be prepared during construction of the proposed Project.

- **Environmental Effects of Solid Waste and Hazardous Material Storage and Handling** - All facilities for the proposed BMOP Project will be designed, constructed, tested, operated, and maintained in accordance with the U.S. Department of Transportation (USDOT) regulations in 49 Code of Federal Regulations (CFR) 195 (Transportation of Hazardous Liquids by Pipeline) and all other applicable federal and state regulations.

Mainline Valves (MLVs) are designed to divide a pipeline into segments for safety reasons, including shutting down product flow and allowing access to the pipeline from the surface. MLVs will be installed on the 42-inch onshore pipeline and the Mainline. These valves will be used for isolation and spill control purposes and will be considered Emergency Flow Restricting Device (EFRD) valves.

MLVs will be installed in locations along the pipeline system that are accessible to authorized employees and that are protected from damage and tampering in accordance with USDOT standards described in 49 CFR Part 195. The MLVs will also be installed in locations along the pipeline system that will minimize damage or pollution from accidental hazardous liquid discharges in accordance USDOT standards. The MLVs will be located in fenced sites and will have electric motor operators installed for operation either locally or remotely.

- **Environmental Effects to Natural Resources** - Routine vegetation management will occur over the full width of the 50-foot-wide permanent Right-of-way (ROW) of the onshore pipelines on an annual basis (PHMSA, 2019). A smaller corridor centered on the pipeline may be cleared as necessary to maintain an herbaceous cover to facilitate corrosion and leak surveys. At waterbody crossings, BMOP will allow a 25-foot-wide riparian buffer to naturally revegetate across the full width of the ROW and will clear a small corridor centered on the pipeline only as necessary to conduct corrosion and leak surveys. In wetlands, routine vegetation management will be conducted in the same manner as in uplands; however, vegetation management of inundated or excessively saturated wetlands will be avoided. Trees will be cleared throughout the permanent ROW.

Question 2: **Does a cost benefit analysis of the environmental impact costs balanced against the social and economic benefits of the proposed facility demonstrate that the latter outweighs the former?**

The proposed project was determined to be necessary to provide the United States (U.S.) essential crude oil transportation and loading services for crude oil produced in the continental U.S. The proposed Project will enhance the country's global competitiveness, operational efficiency, and long-term economic viability.

Significant impacts to the environment are not expected due to the proposed Project. Additionally, as the part of the proposed project PSD permit application, BMOP has evaluated and proposed BACT (40 CFR 52 and LAC 33:III.509.J) limits for applicable emission units; thereby, further reducing any impacts to the environment.

Question 3: **Are there alternative projects which would offer more protection to the environment than the proposed facility without unduly curtailing non-environmental benefits?**

There are no viable alternative projects identified that would offer more environmental protection. With the appropriate BACT implemented, this facility and project will be protective of the environment.

Question 4: **Are there alternative sites which would offer more protection to the environment than the proposed facility site without unduly curtailing non-environmental benefits?**

The DWP will be located approximately eighty two (82) statute miles from the nearest point on the Louisiana coastline (99 statute miles of offshore pipe). This location was specifically chosen to meet the purpose of the project and have the capability to fully load Very Large Crude Carriers (VLCCs) with minimal total impacts, as both the offshore pipeline and the offshore facility at WC 509 are existing. There are no identified alternative sites which would offer more protection to the environment.

Question 5: **Are there mitigating measures which would offer more protection to the environment than the facility as proposed without unduly curtailing non-environmental benefits?**

For the proposed Project, BACT controls will be implemented. The BACT control level cannot be less stringent than the controls required under any applicable federal New Source Performance Standard (NSPS) or National Emission Standard for Hazardous Air Pollutants (NESHAP). Furthermore, BMOP has completed a detailed evaluation of additional control technologies, and have selected the top performing feasible control as BACT. No other feasible control options offer more protection to the environment.

PART 70 OPERATING PERMIT APPLICATION COMPLETENESS CHECKLIST

Instructions: Complete this checklist and submit with the completed air permit application.

LAC 33:III.	Completeness Questions Relative to the Part 70 Permit Application	Yes	No	NA	Location Within the Permit Application
517.A Timely Submittal	Was a Copy of the Application Also Submitted to EPA?	X			
517.B.1,2 Certification	Does the Application include a Certification by a Responsible Official?	X			AAE – Section 10
517.B.3 Certification	Does the Application Include Certification by a Professional Engineer or their Designee:	X			AAE – Section 10
517.D.1 Identifying Information	Does the Application Include:				
	1. Company Name, Physical and Mailing Address of Facility?	X			AAE – Section 1, 2
	2. Map showing Location of the Facility?	X			Appendix A
	3. Owner and Operator Names and Agent?	X			AAE – Section 1
	4. Name and Telephone Number of Plant Manager or Contact?	X			AAE – Section 11
517.D.2 SIC Codes, Source Categories	Does the Application Include a Description of the Source's Processes and Products?	X			Introduction
	Does the Application Include the Source's SIC Code?	X			AAE – Section 5
	Does the Application Include EPA Source Category of HAPs if applicable?	X			AAE – Section 22
517.D.3,6 EIQ Sheets	Has an EIQ Sheet been Completed for each Emission Point whether an Area or Point Source?	X			AAE – Section 23
517.D.4 Monitoring Devices	Does the Application Include Identification and Description of Compliance Monitoring Devices or Activities?	X			AAE – Section 22
517.D.5 Revisions and Modifications Only	For Revisions or Modifications, Does the Application include a Description of the Proposed Change and any Resulting Change in Emissions?			X	
517.D.7 General Information	Does the Application Include Information Regarding Fuels, Fuel Use, Raw Materials, Production Rates, and Operating Schedules as necessary to substantiate emission rates?	X			AAE Section 23 & Appendix B
517 D.8 Operating Limitations	Has Information Regarding any Limitations on Source Operation or any Applicable Work Practice Standards been Identified?	X			AAE Section 23
517.D.9 Calculations	Are Emission Calculations Provided?	X			Appendix B
517.D.10 Regulatory Review	Does the Application Include a Citation and Description of Applicable Louisiana and Federal Air Quality Requirements and Standards?	X			AAE – Section 22

LAC 33:III.	Completeness Questions Relative to the Part 70 Permit Application	Yes	No	NA	Location Within the Permit Application
517.D.11 Test Methods	Has a Description of or a Reference to Applicable Test Methods Used to Determine Compliance with Standards been Provided?			X	
517.D.12 Major Sources of TAPs	Does the Application include Information Regarding the Compliance History of Sources Owned or Operated by the Applicant (per LAC 33.III.5111)?			X	
517.D.13 Major Sources of TAPs	Does the Application include a Demonstration to show that the Source Meets all Applicable MACT and Ambient Air Standard Requirements?	X			See PSD Air Construction Permit Application Volume 2
517.D.14 PSD Sources Only	If Required by DEQ, Does the Application Include Information Regarding the Ambient Air Impact for Criteria Pollutants as Required for the Source Impact Analysis per LAC 33:III.509.K, L, and M?	X			See PSD Air Construction Permit Application Volume 2
517 D.15 PSD Sources Only	If Required by DEQ, Does the Application Include a Detailed Ambient Air Analysis?	X			See PSD Air Construction Permit Application Volume 2
517.D.16, 18	Has any Additional Information been Provided?	X			Introduction
517.D.17 Fees	Has the Fee Code been Identified?	X			AAE – Section 5
	Is the Applicable Fee Included with the Application?	X			See Cover Letter
517.E.1 Additional Part 70 Requirements	Does the Certification Statement Include a Description of the Compliance Status of Each Emission Point in the Source with All Applicable Requirements?	X			AAE – Section 10
517E.2 Additional Part 70 Requirements	Does the Certification Statement Include a Statement that the Source will continue to Comply with All Applicable Requirements with which the Source is in Compliance?	X			AAE – Section 10
517.E.3 Additional Part 70 Requirements	Does the Certification Statement Include a Statement that the Source will, on a timely basis, meet All Applicable Requirements that will Become Effective During the Permit Term?	X			AAE – Section 10
517.E.4 Additional Part 70 Requirements	Are there Applicable Requirements for which the Source is not in Compliance at the Time of Submittal?		X		
	Does the Application include a Compliance Plan Schedule?			X	
	Does the Schedule Include Milestone Dates for which Significant Actions will occur?			X	
	Does the Schedule Include Submittal Dates for Certified Progress Reports?			X	

LAC 33:III.	Completeness Questions Relative to the Part 70 Permit Application	Yes	No	NA	Location Within the Permit Application
517.E.5 Additional Part 70 Requirements Acid Rain	Is this Source Covered by the Federal Acid Rain Program?		X		
	Are the Requirements of LAC 33.III.517.E 1-4 included in the Acid Rain Portion of the Compliance Plan?			X	
517.E.6 Additional Part 70 Requirements	Have any Exemptions from any Applicable Requirements been Requested?	X			AAE – Section 22
	Is the List and explanations Provided?	X			AAE – Section 22
517.E.7 Additional Part 70 Requirements	Does the Application Include a Request for a Permit Shield?	X			See Section 1 of the Title V Air Operating Permit Application for the Permit Shield Request
	Does the Request List those Federally Applicable Requirements for which the Shield is Requested along with the Corresponding Draft Permit Terms and conditions which are Proposed to Maintain Compliance?	X			See Section 1 of the Title V Air Operating Permit Application for the Permit Shield Request
517.E.8 Additional Part 70 Requirements	Does the Application Identify and Reasonably Anticipated Alternative Operating Scenarios?			X	
	Does the Application include Sufficient Information to Develop permit Terms and Conditions for Each Scenario, Including Source Process and Emissions Data?			X	
517.F Confidentiality	Does the Application Include a Request for Non-Disclosure (Confidentiality)?	X			AAE – Section 3
525.B. Minor Permit Modifications	Does the Application Include a Listing of New Requirements Resulting for the Change?			X	
	Does the Application Include Certification by the Responsible Official that the Proposed Action Fits the Definition of a Minor Modification as per LAC 33:III.525.A.			X	
	Does the Certification also Request that Minor Modification Procedures be Used?			X	
	Does the Application, for Part 70 Sources, Include the Owner's Suggested Draft Permit and Completed Forms for the Permitting Authority to Use to Notify Affected States?			X	

LAC 33:III.	Completeness Questions Relative to the Part 70 Permit Application	Yes	No	NA	Location Within the Permit Application
La. R.S. 30:2018 – PSD/NNSR only	Has a copy of the answers to the questions posed in the Environmental Assessment Statement (Section 25) been sent to the local governing authority at no cost to the local governing authority?	X			
	Has a copy of the answers to the questions posed in the Environmental Assessment Statement (Section 25) been sent to the designated public library at no cost to the designated public library?	X			

APPENDIX C. DETAILED EMISSIONS CALCULATIONS

Normal Operations Emission Calculations

Stationary Summary

	NO_X (tpy)	CO (tpy)	VOC (tpy)	SO_2 (tpy)	PM Filterable (tpy)	PM_{10}[1] (tpy)	$PM_{2.5}$[1] (tpy)	H_2S (tpy)	H_2SO_4 (tpy)	Total VOC HAPs (tpy)	CO_2e (tpy)
Marine Loading											
Crude Oil Loading	--	--	1,604	--	--	--	--	0.70	--	89.9	--
Vapor Capture - VCU Stack #1	143	263	260	4.25	1.25	4.99	4.99	0.11	--	14.6	157,510
Vapor Capture - VCU Stack #2	143	263	260	4.25	1.25	4.99	4.99	0.11	--	14.6	157,510
Vapor Capture - VCU Stack #3	143	263	260	4.25	1.25	4.99	4.99	0.11	--	14.6	157,510
Vapor Capture - Low Pressure Flare	4.03	8.05	52.9	0.32	--	--	--	--	--	2.96	4,815
Supporting Platform Operations											
Natural Gas - High Pressure Flare	1.03	2.06	0.14	1.24E-03	--	--	--	--	--	0.013	886
Power Generation - Natural Gas Engines (x2)	11.2	5.17	6.29	0.05	6.14E-03	0.80	0.80	--	2.34E-03	4.22	12,871
Emergency Diesel Generator	0.15	0.13	0.15	0.02	7.40E-03	8.61E-03	8.61E-03	--	5.00E-04	6.10E-04	25.8
Platform B Cranes (x2)	2.05	11.97	0.97	1.48	0.10	0.21	0.21	--	0.05	0.06	2,383
Platform B Firewater Pump Engine	0.21	0.19	0.21	0.02	0.01	0.01	0.01	--	7.22E-04	3.58E-04	37.2
Platform C Firewater Pump Engine	0.21	0.19	0.21	0.02	0.01	0.01	0.01	--	7.22E-04	3.58E-04	37.2
Aviation Fuel Tank	--	--	5.12E-04	--	--	--	--	--	--	7.65E-05	--
Platform B Cranes Diesel Tank #1	--	--	1.93E-03	--	--	--	--	--	--	2.65E-04	--
Platform B Cranes Diesel Tank #2	--	--	1.93E-03	--	--	--	--	--	--	2.65E-04	--
Primary Diesel Tank	--	--	8.51E-03	--	--	--	--	--	--	1.17E-03	--
Surge Tank #1	--	--	3.73	--	--	--	--	--	--	0.07	--
Piping Components	--	--	23.7	--	--	--	--	5.09E-03	--	2.96	1,211
Total	**449**	**817**	**2,473**	**14.66**	**3.88**	**16.0**	**16.0**	**1.04**	**0.05**	**144**	**494,797**

[1] PM_{10} and $PM_{2.5}$ emissions are represented as the sum of filterable PM_{10}/$PM_{2.5}$ and condensable emissions.

Operations Emission Calculations
BMOP - Loading Operations

Maximum Hourly Loading Rate [1]	=	80,000	bbl/hr	
	=	3,360	1,000 gal/hr	
Maximum Annual Loading Rate [1]	=	605,000,000	bbl/yr	
	=	25,410,000	1,000 gal/yr	
Vapor Capture System Collection Efficiency [5]	=	99	%	
Vapor Capture System Maintenance Alllowance [5]	=	629	hrs/yr offline while loading	
Crude Oil Loading Specifications		Maximum	Annual	
TOC Arrival Emission Factor [1]	=	0.86	0.86	
VOC Arrival Emission Factor [2]	=	0.731	0.731	
Loading Temperature [1]	=	550	532	°R
Vapor Molecular Weight [1]	=	50	50	lb/lbmol
Crude Oil Liquid Molecular Weight [1]	=	207	207	lb/lbmol
True Vapor Pressure [1]	=	10.99	9.00	psia
Liquid H_2S Partition [3]	=	25	21	
H2S Molecular Weight	=	34.1	34.1	lb/lbmol

Criteria Pollutants

Pollutant	Emission Factor Basis		Hourly Emission Factor		Annual Emission Factor		Max Hourly Loading Vapors	Avg Hourly Loading Vapors	Annual Loading Vapors	Uncaptured Loading Emissions
			Value	Units	Value	Units	lb/hr	lb/hr	tpy	tpy
VOC	AP-42	[2]	1.48	lb/1,000 gal	1.36	lb/1,000 gal	4,989	4,553	17,216	1,604
H_2S	Site Specific	[3], [4]	125	ppmw	5	ppmw	64.55	1.98	7.48	0.70

[1] Based on current project design specifications, provided by BMOP. Molecular weight referenced from AP-42, Chapter 7, Table 7.1-2.
[2] Per AP-42, Table 5.2-3 for crude oil loading into ships (uncleaned). Total loading loss based on AP-42, Section 5.2 Equations 2 and 3 (06/08).
[3] Mass balance based and liquid H_2S partition factors from the Petroleum Processing Handbook, McGraw-Hill, New York, Figure 12-71, page 12-93. Short-term H2S concentration from Nederland permit basis.
[4] Annual mass H2S emissions calculated from a conservative assumption of 5 ppmw. The average of all samples from Nederland (>3000 samples) is 1.31 ppmw.
[5] Expected vapor capture of total loading emissions when vapor capture system is employed. Assumed no vapor capture during maintenance allowance in accordance with 40 CFR 63.561.

Operations Emission Calculations
BMOP - Loading Operations

Hazardous Air Pollutants

Crude Oil HAP Speciation (%)[5]			99% UPL[6]	99% UPL[7]	Nederland Basis[8]	Maximum HAP[9]	Max Hourly Emissions[10]	Avg Hourly Loading Vapors	Annual Emissions	Uncaptured Loading Emissions
HAP	**Mass %, liquid**	**Mass %, vapor**	**Mass %, liquid**	**Mass %, vapor**	**Mass %, vapor**	**Mass %, vapor**	**lb/hr**	**lb/hr**	**tpy**	**tpy**
Hexane	2.07%	3.11%	3.09%	4.09%	3.38%	4.09%	204.0	186.2	704.1	65.6
Benzene	0.25%	0.19%	0.46%	0.34%	0.80%	0.80%	39.93	36.44	137.8	12.8
Toluene	0.69%	0.20%	1.10%	0.29%	0.36%	0.36%	17.73	16.18	61.18	5.70
Ethylbenzene	0.16%	0.01%	0.29%	0.02%	0.05%	0.05%	2.48	2.26	8.55	0.80
1,2,4-Trimethylbenzene	0.44%	0.007%	0.76%	0.01%		0.01%	0.53	0.49	1.84	0.17
1,3-dimethylbenzene	0.43%	0.04%	0.79%	0.05%		0.05%	2.38	2.17	8.20	0.76
1,4-dimethylbenzene	0.31%	0.03%	0.57%	0.03%		0.03%	1.66	1.51	5.71	0.53
1,2-dimethylbenzene (Xylene)	0.21%	0.01%	0.37%	0.02%	0.21%	0.21%	10.36	9.46	35.76	3.33
i-propylbenzene (Cumene)	0.04%	0.002%	0.08%	0.003%	0.006%	0.01%	0.29	0.27	1.01	0.09
Biphenyl[6]					0.00002%	0.00002%	0.001	0.00	0.003	0.00032
Cresols[6]					0.0007%	0.001%	0.04	0.03	0.12	0.012
Naphthalene[6]					0.0006%	0.001%	0.03	0.03	0.11	0.010
Phenol[6]					0.001%	0.001%	0.07	0.07	0.26	0.024
Total HAP	**4.59%**	**3.60%**	**7.50%**	**4.86%**	**4.80%**	**5.60%**	**279.5**	**255.1**	**965**	**89.9**

[5] Maximum mass % in liquid of individual HAP from 13 samples of various crude types taken at Nederland from May and June 2020 and analyzed per Method D7900, *Standard Test Method for Determination of Light Hydrocarbons in Stabilized Crude Oils by Gas Chromatography*.
Vapor weight percent calculated assuming annual average temperature.
[6] Calculation of the 99% Upper Prediction Limit (UPL) mass percent in liquid, based on the results of the 13 samples from Nederland, by individual HAP.
[7] Calculation of the 99% Upper Prediction Limit (UPL) mass percent in vapor, based on the calculated vapor speciation using results of the 13 samples from Nederland, by individual HAP.
[8] Speciated VOC components, vapor weight %, from the permit basis for the Nederland Terminal, which references Table 3-1 of API Publication 1673 (May 1998), and factors obtained from Mr. James Durham, EPA Office of Air Quality Planning and Standards.
[9] The maximum of the calculated sample mass %, vapor, the Nederland permit basis, or the 99% UPL of the mass %, vapor, by individual HAP.
[10] Calculated as a percent of VOC emissions, as the crude samples demonstrated >99.9% is VOC.
Note that the "Total HAP" is the sum of all max individual HAP from the 13 samples.

Normal Operations Emission Calculations

BMOP - Vapor Combustion Unit Stacks

Total Operating Time [1]	=	8,760	hrs/yr
Operating Load [1]	=	100%	
Total Number of Units [1]	=	3	
Fuel Type [1]	=	VLCC Vapors, Assist Natural Gas, Pilot Natural Gas	
Maximum Heat Input Rate [1]	=	218.09	MMBtu/hr/stack
Average Higher Heating Value (HHV) [2]	=	1,456	MMBtu/MMscf
Vessel Loading Rate [1]	=	80,000	bbl/hr
Waste Gas Molecular Weight [3]	=	50	lb/lbmol
Destruction and Removal Efficiency [1]	=	95	%

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions from 1 Unit	Annual Emissions from 1 Unit	Hourly Emissions from All Units	Annual Emissions from All Units
			Value	Units	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
$PM_{Filterable}$	AP-42	[4],[5]	1.9	lb/MMscf	0.28	1.25	0.85	3.74
$PM_{10, Filterable}$	AP-42	[4],[5]	1.9	lb/MMscf	0.28	1.25	0.85	3.74
$PM_{2.5, Filterable}$	AP-42	[4],[5]	1.9	lb/MMscf	0.28	1.25	0.85	3.74
$PM_{Condensable}$	AP-42	[4]	5.7	lb/MMscf	0.85	3.74	2.56	11.22
NO_x	VCU Estimate	[7]	0.15	lb/MMBtu	32.71	143.3	98.14	429.9
SO_2	Crude H2S Content	[6]	5	ppmw	40.02	4.25	120.1	12.8
CO	VCU Estimate	[7]	0.28	lb/MMBtu	60.08	263.2	180.3	789.5
VOC	Vendor Data	[8]	95	%	82.32	260.2	247.0	780.6
H_2S	Vendor Data	[8]	95	%	1.07	0.11	3.20	0.34

[1] Based on current project design specifications, provided by BMOP and John Zink Hamworthy Combustion (2021), or equivalent. Each vapor combustion unit is assumed to have a maximum heat input rate of 218.09 MMBtu/hr, which is the instantaneous heat input rate at 100% vessel loading, which represents a short-term maximum. The average heat input rate for an entire vessel is far lower.

[2] Heating value of waste gas based on displaced vapors and assist gas usage at Bakken Pipeline during 100% vessel loading.

[3] Vapor molecular weight and H_2S content from crude oil specifications for Nederland Marine Terminal permit, as provided by Energy Transfer on December 6, 2022.

[4] Emission factors from AP-42, Table 1.4-2, Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion (July 1998).

[5] Conservatively assume $PM_{total} = PM_{10} = PM_{2.5}$.

[6] From crude oil specifications provided by Energy Transfer, the annual average H_2S composition is 5 ppmw. SO_2 emissions have been calculated from mass balances, assuming that 100 percent of H_2S (MW = 34) in combusted vapors is oxidized to SO_2 (MW = 64) based on Attachment A of TCEQ's NSR Guidance for Flares and Vapor Combustors: Emission Calculations (March 2021).

[7] NO_X and CO emission factor estimated for VCU sized to fit on the WC 509 Platform Complex.

[8] VOC emissions based on a sea floor annual average temperature of 72.66°F and average TVP of 3 psia and 80,000 bbl/hr, as assumed by John Zink Hamworthy Combustion in VCU specifications (2021), with VCU vendor DRE specifications.

Normal Operations Emission Calculations

BMOP - Vapor Combustion Unit Stacks

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions from 1 Unit	Annual Emissions from 1 Unit	Hourly Emissions from All Units	Annual Emissions from All Units
			Value	Units	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
Hexane	Vendor Data	[8]	95	%	3.37	10.64	10.10	31.92
Benzene	Vendor Data	[8]	95	%	0.66	2.08	1.98	6.25
Toluene	Vendor Data	[8]	95	%	0.29	0.92	0.88	2.77
Ethylbenzene	Vendor Data	[8]	95	%	0.04	0.13	0.12	0.39
1,2,4-Trimethylbenzene	Vendor Data	[8]	95	%	8.80E-03	0.03	0.03	0.08
1,3-dimethylbenzene	Vendor Data	[8]	95	%	0.04	0.12	0.12	0.37
1,4-dimethylbenzene	Vendor Data	[8]	95	%	0.03	0.09	0.08	0.26
1,2-dimethylbenzene (Xylene)	Vendor Data	[8]	95	%	0.17	0.54	0.51	1.62
i-propylbenzene (Cumene)	Vendor Data	[8]	95	%	4.83E-03	0.02	0.01	0.05
Biphenyl	Vendor Data	[8]	95	%	1.65E-05	5.20E-05	4.94E-05	1.56E-04
Cresols	Vendor Data	[8]	95	%	5.93E-04	1.87E-03	1.78E-03	5.62E-03
Naphthalene	Vendor Data	[8]	95	%	5.19E-04	1.64E-03	1.56E-03	4.92E-03
Phenol	Vendor Data	[8]	95	%	1.23E-03	3.88E-03	3.68E-03	1.16E-02
Total VOC HAPs					**4.61**	**14.58**	**13.84**	**43.74**

Normal Operations Emission Calculations

BMOP - Vapor Combustion Unit Stacks

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions from 1 Engine	Annual Emissions from 1 Engine	Hourly Emissions from All Units	Annual Emissions from All Units
			Value	Units	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
CO_2	EPA	[9]	74.54	kg/MMBtu	35,839	156,976	107,518	470,928
CH_4	EPA	[10]	3.00E-03	kg/MMBtu	1.44	6.32	4.33	18.95
N_2O	EPA	[10]	6.00E-04	kg/MMBtu	0.29	1.26	0.87	3.79
CO_2e	EPA	[11]	--	--	**35,961**	**157,510**	**107,884**	**472,531**

[9] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for unfinished oils was used to calculate emissions.

[10] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[11] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

Normal Operations Emission Calculations

BMOP - 509A Low Pressure Flare

Number of Loaded Vessels [1]	=	275	vessels/yr	
Total Operating Time [1]	=	275	hr/yr	
Waste Gas Type [1]	=	VLCC Vapors and Pilot Natural Gas		
Waste Gas Heating Value [2]	=	1,456	Btu/scf	
Waste Gas Molar Flow [3]	=	3.5	MMSCFD	
		145,833	scf/hr	
Crude Oil Specifications				
Vapor Molecular Weight [4]	=	50	lb/lbmol	
Crude Oil Liquid Molecular Weight [4]	=	207	lb/lbmol	
		Maximum	Annual Average	
Liquid H_2S Partition [4]	=	25	21	
H_2S Composition [4]	=	125	25	ppmw

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Low Pressure Flare Emissions	
			Value	Units	(lb/hr)	(tons/yr)
NO_x	High Btu	[5]	0.138	lb/MMBtu	29.3	4.03
CO	High Btu	[5]	0.2755	lb/MMBtu	58.5	8.05
SO_2	Crude H_2S Content	[4],[6]	-	-	13.78	0.32
VOC	Crude Sampling	[4],[7]	-	-	385	52.9

[1] Based on BMOP VLCC ship loading schedule provided on October 24, 2022. The low pressure flare is operated during pigging of the vapor line in a 1-hour period following loading of each vessel. Approximately 275 vessels are unloaded at the platform per year.

[2] Heating value of waste gas based on assist gas usage at Bakken Pipeline during 100% vessel loading.

[3] Flare specifications from Wood provided on December 12, 2022.

[4] Crude oil specifications for Nederland Marine Terminal permit, as provided by Energy Transfer on December 6, 2022.

[5] Emission factor expectations for a high Btu gas stream controlled by a flare that is not steam assisted.

[6] SO_2 emissions have been calculated from mass balances using the crude oil specifications from Energy Transfer, assuming that 100% of H_2S (MW = 34) in flared gas is oxidized to SO_2 (MW = 64) and that all components of the VLCC vapor are VOCs (see note 7).

Example Emissions Calculation (Annual):

SO_2 (tpy) = 5 lb $H_2S/10^6$ lb liquid x (207 lb liquid)/(34 lb H_2S) x (145,833 scf vapor/hr x 50 lb vapor/lb-mol x 1 lbmol/379 scf)/(50 lb/lbmol vapor) x 25 (lbmol H_2S/lbmol vapor) x (64 lb/lbmol SO_2)/(34 lb/lbmol H_2S) x 275 hr/yr x 1 ton/2,000 lbs

[7] Based on the definition of VOCs in 40 CFR 51.100 and the crude oil profile used for permitting of the Nederland Marine Terminal provided by Energy Transfer on March 19, 2020, all components of the VLCC vapor are assumed to be VOCs. VOCs are assumed to have a destruction and removal efficiency (DRE) of 98% in the flare.

Emission Factor Calculation:

VOC (lb/hr) = 145,833 scf/hr x 1 lbmol/379 scf x 50 lb/lbmol x [1 - DRE (%)]

Normal Operations Emission Calculations

BMOP - 509A Low Pressure Flare

Hazardous Air Pollutants

Pollutant	Basis		Composition		Low Pressure Flare Emissions	
			Value	Units	(lb/hr)	(tons/yr)
Hexane	Crude Sampling	[8]	4.09	wt %	15.74	2.16
Benzene	Crude Sampling	[8]	0.80	wt %	3.08	0.42
Toluene	Crude Sampling	[8]	0.36	wt %	1.37	0.19
Ethylbenzene	Crude Sampling	[8]	0.05	wt %	0.19	0.03
1,2,4-Trimethylbenzene	Crude Sampling	[8]	0.01	wt %	0.04	5.66E-03
1,3-Dimethylbenzene	Crude Sampling	[8]	0.05	wt %	0.18	0.03
1,4-Dimethylbenzene	Crude Sampling	[8]	0.03	wt %	0.13	0.02
1,2-Dimethylbenzene	Crude Sampling	[8]	0.21	wt %	0.80	0.11
Cumene	Crude Sampling	[8]	0.01	wt %	0.02	3.11E-03
Total VOC HAPs					**21.55**	**2.96**

[8] Maximum mass % in liquid of individual HAP from 13 samples of various crude types taken at Nederland from May and June 2020 and analyzed per Method D7900, Standard Test Method for Determination of Light Hydrocarbons in Stabilized Crude Oils by Gas Chromatography. Vapor weight percent calculated assuming annual average temperature. VOCs are assumed to have a destruction and removal efficiency (DRE) of 98% in the flare.

Example Calculation (Hexane):

Hexane (lb/hr) = 145,833 scf/hr x 1 lbmol/379 scf x 50 lb vapor/lbmol x 2.07 lb hexane/100 lb vapor x [1 - DRE (%)]

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Low Pressure Flare Emissions	
			Value	Units	(lb/hr)	(tons/yr)
CO_2	EPA	[9]	74.54	kg/MMBtu	34,901	4,799
CH_4	EPA	[10]	3.00E-03	kg/MMBtu	1.40	0.19
N_2O	EPA	[10]	6.00E-04	kg/MMBtu	0.28	0.04
CO_2e	EPA	[11]	--	--	**35,020**	**4,815**

[9] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for unfinished oils was used to calculate emissions.

[10] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[11] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

Normal Operations Emission Calculations

BMOP - 509A High Pressure Flare

Total Operating Time [1]	=	11	hr/event
Events Per Year	=	1	
Waste Gas Type [1]	=	Natural Gas	
Average Waste Gas Higher Heating Value [2]	=	1,020	Btu/scf
Waste Gas Molar Flow [3]	=	32	MMSCFD
		1,333,333	scf/hr

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		High Pressure Flare Emissions	
			Value	Units	(lb/hr)	(tons/yr)
NO_x	High Btu	[4]	0.138	lb/MMBtu	187.7	1.03
CO	High Btu	[4]	0.2755	lb/MMBtu	375	2.06
SO_2	Fuel S Content	[5]	0.17	lb/MMscf	0.23	1.24E-03
VOC	Fuel Content	[4],[6]	18.64	lb/MMscf	24.85	0.14

[1] Based on current project design specifications, provided by BMOP. The high pressure flare is operated during periodic pigging of the natural gas line to the platform. Each pigging event lasts around 11 hours. Pigging is expected to occur once per 7 years, but is conservatively assumed to occur once per year.

[2] Average higher heating value of natural gas from footnote a of AP-42, Table 1.4-1, Emission Factors for Nitrogen Oxides and Carbon Monoxide from Natural Gas Combustion (July 1998).

[3] Flare specifications from Wood provided on December 12, 2022.

[4] Emission factor expectations for a high Btu gas stream controlled by a flare that is not steam assisted.

[5] Based on natural gas from the Stingray system with 0.0001% H2S (by volume). SO_2 emissions have been calculated from mass balances, assuming that 100 percent of sulfur (MW = 32) in combusted fuel is oxidized to SO_2 (MW = 64).

Emission Factor Calculation:

SO_2 (lb/MMscf) = 0.0001 lbmol H_2S/100 lbmol fuel gas x 1 lbmol fuel gas/379 scf x 10^6 scf/1 MMscf x (1 lbmol SO_2)/(1 lbmol H_2S) x 64 lb/lbmol SO_2

[6] VOC emissions found using the fuel gas composition at the WC 509 Platform Complex from the Stingray system. VOCs are assumed to have a generic destruction and removal efficiency (DRE) of 98% and a DRE of 99% for compounds containing no more than 3 carbons.

Example Emission Factor Calculation (Propane):

Propane (lb/MMscf) = 0.84 lbmol propane/100 lbmol fuel gas x 1 lbmol fuel gas/379 scf x 10^6 scf/1 MMscf x 44.1 lb/lbmol propane x [1 - DRE (%)]

VOC	*MW*	*% vol*	*DRE*	*Emissions (lb/MMscf)*
Propane	44.1	0.84	99%	9.77
N-Butane	58.12	0.18	98%	5.52
N-Pentane	72.15	0.04	98%	1.52
Hexane	86.18	0.04	98%	1.82
Total	-	-	-	18.64

Normal Operations Emission Calculations

BMOP - 509A High Pressure Flare

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		High Pressure Flare Emissions	
			Value	Units	(lb/hr)	(tons/yr)
Hexane	Fuel Content	[6]	1.82	lb/MMscf	2.43	1.33E-02
Total VOC HAPs					**2.43**	**1.33E-02**

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		High Pressure Flare Emissions	
			Value	Units	(lb/hr)	(tons/yr)
CO_2	EPA	[8]	53.06	kg/MMBtu	159,089	875
CH_4	Fuel Content, EPA	[9]	5.76E-02	lb/MMBtu	78.31	0.43
N_2O	EPA	[10]	4.32E-06	lb/MMBtu	0.01	3.23E-05
CO_2e	EPA	[11]	--	--	**161,048**	**885.8**

[8] Emission factor for natural gas combustion from 40 CFR 98 Subpart C, Table C-1, Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel.

[9] CH_4 emissions are composed of (i) natural gas combustion by the flare and (ii) releases of uncombusted CH_4 present in the natural gas.

(i) Emission factors for natural gas combustion from 40 CFR 98 Subpart C, Table C-2, Default CH4 and N2O Emission Factors for Various Types of Fuel. The flare is assumed to have a generic destruction and removal efficiency of 98%.

CH_4 from Natural Gas Combustion = 0.98 x (2 x 10^{-5} kg CH_4/MMBtu) x 2.20462 lb/kg = 4.32E-05 lb/MMBtu

(ii) Releases of uncombusted CH_4 found using the fuel gas composition (CH_4 = 92.79 vol% of fuel gas) representative of the Stingray system. CH_4 is assumed to have a destruction and removal efficiency (DRE) of 99%.

Uncombusted CH_4 = 0.01 x 92.79 lbmol CH4/100 lbmol gas x 379 scf/lbmol gas x 1,020 Btu/scf x 1 MMBtu/106 Btu x 16 lb/lbmol CH4 = 5.75E-02 lb/MMBtu

Total CH4 Emission Factor = 5.76E-02 lb/MMBtu

[10] Emission factors for natural gas combustion from 40 CFR 98 Subpart C, Table C-2, Default CH4 and N2O Emission Factors for Various Types of Fuel. The flare is assomed to have a generic destruction and removal efficiency of 98%.

N_2O from Natural Gas Combustion = 0.98 x (2 x 10^{-6} kg CH_4/MMBtu) x 2.20462 lb/kg = 4.32E-06 lb/MMBtu

[11] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

Normal Operations Emission Calculations

BMOP - Platform Natural Gas Generators

Engine Rating [1]	=	1,736	kW
	=	2,328	HP
Total Operating Time [1]	=	8,760	hrs/yr
Operating Load [1]	=	100%	
Total Number of Main Engines [1]	=	1 engine at any one time	
Fuel Type [1]	=	Natural Gas, 4-Stroke Lean Burn	
Average Brake-Specific Fuel Consumption [2]	=	17,820	scf/hr
Average Higher Heating Value (HHV) [4]	=	1,020	Btu/scf
Average Heat Input Rate	=	18.18	MMBtu/hr

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
$PM_{Filterable}$	AP-42	[4]	7.71E-05	lb/MMBtu	1.40E-03	6.14E-03
$PM_{10, Filterable}$	AP-42	[4]	7.71E-05	lb/MMBtu	1.40E-03	6.14E-03
$PM_{2.5, Filterable}$	AP-42	[4]	7.71E-05	lb/MMBtu	1.40E-03	6.14E-03
$PM_{Condensable}$	AP-42	[4]	9.91E-03	lb/MMBtu	0.18	0.79
NO_x	Vendor	[3]	0.5	g/HP-hr	2.57	11.24
SO_2	AP-42	[4]	5.88E-04	lb/MMBtu	0.01	0.05
CO	Vendor	[3]	0.23	g/HP-hr	1.18	5.17
VOC	Vendor	[3]	0.3	g/HP-hr	1.44	6.29
H_2SO_4	Conversion	[5]	5	% of SO_2	5.34E-04	2.34E-03

[1] Based on current project design specifications, provided by BMOP. The BMOP Platform complex will operate 2 engines, however, only one will be operating at any given time.

[2] Per Manufacturer Specification sheet for a Caterpillar G3516C (based on 100% load).

[3] Vendor expected emissions from Caterpillar G3516C with oxidation catalyst. VOC emissions non-methane, non-ethane hydrocarbons, on a methane basis.

[4] Emission factors are based on AP-42 Chapter 3, Table 3.2-2, Uncontrolled Emission Factors for 4-Stroke Lean Burn Engines (July 2000). Assume filterable PM = PM_{10} = $PM_{2.5}$.

[5] Assumes 5% of SO_2 emissions are converted to H_2SO_4; this is a more conservative approach compared to the assumption that 2% of SO_2 emissions are converted to H_2SO_4 as stated in the Toxics Release Inventory Guidance for Reporting Sulfuric Acid, EPA 745-B-20-004 (February 2020).

Normal Operations Emission Calculations

BMOP - Platform Natural Gas Generators

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
Acenaphthene	AP-42	[6]	1.25E-06	lb/MMBtu	2.27E-05	9.95E-05
Acenaphthylene	AP-42	[6]	5.53E-06	lb/MMBtu	1.01E-04	4.40E-04
Acetaldehyde	AP-42	[6]	8.36E-03	lb/MMBtu	0.15	0.67
Acrolein	AP-42	[6]	5.14E-03	lb/MMBtu	0.09	0.41
Benzene	AP-42	[6]	4.40E-04	lb/MMBtu	8.00E-03	0.04
Benzo(b)fluoranthene	AP-42	[6]	1.66E-07	lb/MMBtu	3.02E-06	1.32E-05
Benzo(e)pyrene	AP-42	[6]	4.15E-07	lb/MMBtu	7.54E-06	3.30E-05
Beno(g,h,i)perylene	AP-42	[6]	4.14E-07	lb/MMBtu	7.53E-06	3.30E-05
Biphenyl	AP-42	[6]	2.12E-04	lb/MMBtu	3.85E-03	0.02
Butadiene (1,3-)	AP-42	[6]	2.67E-04	lb/MMBtu	4.85E-03	0.02
Carbon Tetrachloride	AP-42	[6]	3.67E-05	lb/MMBtu	6.67E-04	2.92E-03
Chlorobenzene	AP-42	[6]	3.04E-05	lb/MMBtu	5.53E-04	2.42E-03
Chloroform	AP-42	[6]	2.85E-05	lb/MMBtu	5.18E-04	2.27E-03
Chrysene	AP-42	[6]	6.93E-07	lb/MMBtu	1.26E-05	5.52E-05
Dichloropropene (1,3-)	AP-42	[6]	2.64E-05	lb/MMBtu	4.80E-04	2.10E-03
Ethylbenzene	AP-42	[6]	3.97E-05	lb/MMBtu	7.22E-04	3.16E-03
Ethylene Dibromide	AP-42	[6]	4.43E-05	lb/MMBtu	8.05E-04	3.53E-03
Fluoranthene	AP-42	[6]	1.11E-06	lb/MMBtu	2.02E-05	8.84E-05
Fluorene	AP-42	[6]	5.67E-06	lb/MMBtu	1.03E-04	4.51E-04
Formaldehyde	ZZZZ	[7]	14	ppmvd	0.61	2.67
Methanol	AP-42	[6]	2.50E-03	lb/MMBtu	0.05	0.20
Methylene Chloride	AP-42	[6]	2.00E-05	lb/MMBtu	3.64E-04	1.59E-03
Methylnaphthalene (2-)	AP-42	[6]	3.32E-05	lb/MMBtu	6.03E-04	2.64E-03
n-Hexane	AP-42	[6]	1.11E-03	lb/MMBtu	0.02	0.09
Naphthalene	AP-42	[6]	7.44E-05	lb/MMBtu	1.35E-03	5.92E-03
PAH	AP-42	[6]	2.69E-05	lb/MMBtu	4.89E-04	2.14E-03
Phenanthrene	AP-42	[6]	1.04E-05	lb/MMBtu	1.89E-04	8.28E-04
Phenol	AP-42	[6]	2.40E-05	lb/MMBtu	4.36E-04	1.91E-03
Pyrene	AP-42	[6]	1.36E-06	lb/MMBtu	2.47E-05	1.08E-04
Styrene	AP-42	[6]	2.36E-05	lb/MMBtu	4.29E-04	1.88E-03
Tetrachloroethane	AP-42	[6]	2.48E-06	lb/MMBtu	4.51E-05	1.97E-04
Toluene	AP-42	[6]	4.08E-04	lb/MMBtu	7.42E-03	0.03
Tetrachloroethane (1,1,2,2-)	AP-42	[6]	4.00E-05	lb/MMBtu	7.27E-04	3.18E-03
Trichloroethane (1,1,2-)	AP-42	[6]	3.18E-05	lb/MMBtu	5.78E-04	2.53E-03
Trimethylpentane (2,2,4-)	AP-42	[6]	2.50E-04	lb/MMBtu	4.54E-03	0.02
Vinyl Chloride	AP-42	[6]	1.49E-05	lb/MMBtu	2.71E-04	1.19E-03
Xylene	AP-42	[6]	1.84E-04	lb/MMBtu	3.34E-03	0.01
Total VOC HAPs					**0.96**	**4.22**

[6] Emission factors are based on AP-42 Chapter 3, Table 3.2-2, Uncontrolled Emission Factors for 4-Stroke Lean Burn Engines (July 2000).

[7] Per Table 2a of 40 CFR 63 Subpart ZZZZ, subject 4SLB engines may comply with 14 ppmvd HCHO at 15% O_2.

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
CO_2	Manuf. Spec.	[8]	617	g/kW-hr	2,361	10,343
CH_4	Manuf. Spec.	[8]	6.02	g/kW-hr	23.04	100.9
N_2O	EPA	[9]	1.00E-04	kg/MMBtu	4.01E-03	0.02
CO_2e	EPA	[10]	--	--	**2,939**	**12,871**

[8] Per Manufacturer Specification sheet for a Caterpillar G3516C (based on 100% load).

[9] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for natural gas was used to calculate emissions.

[10] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

Normal Operations Emission Calculations

BMOP - Platform Diesel Generators

Engine Rating [1]	=	336	kW
	=	450	HP
Total Operating Time [1]	=	100	hrs/yr
Operating Load [1]	=	100%	
Total Number of Main Engines [1]	=	1	
Fuel Type [1]	=	Diesel	
Average Brake-Specific Fuel Consumption [2]	=	7,000	Btu/HP-hr
Average Higher Heating Value (HHV) [2]	=	19,300	Btu/lb
Average Heat Input Rate	=	3.15	MMBtu/hr

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
$PM_{Filterable}$	EPA	[3]	0.20	g/kW-hr	0.15	0.01
$PM_{10, Filterable}$	EPA	[3]	0.20	g/kW-hr	0.15	0.01
$PM_{2.5, Filterable}$	EPA	[3]	0.20	g/kW-hr	0.15	0.01
$PM_{Condensable}$	AP-42	[5]	7.70E-03	lb/MMBtu	0.02	1.21E-03
NO_x	EPA	[3]	4.0	g/kW-hr	2.96	0.15
SO_2	Fuel S Content	[4]	7.11E-04	lb/HP-hr	0.32	0.02
CO	EPA	[3]	3.5	g/kW-hr	2.59	0.13
VOC	EPA	[3]	4.0	g/kW-hr	2.96	0.15
H_2SO_4	Fuel S Content	[4]	2.22E-05	lb/HP-hr	0.01	5.00E-04

[1] Based on current project design specifications, provided by BMOP.

[2] Based on AP-42 Chapter 3, Table 3.3-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines (October 1996).

[3] Per 40 CFR 60.4202(a)(2) and Table 3 of Appendix I to 40 CFR 1039. Conservatively assume that NO_X and VOC emissions are equivalent to the NMHC + NO_X emissions limit. Conservatively assume that filterable PM = PM_{10} = $PM_{2.5}$.

[4] A sulfur content of 0.1% is used for all diesel combustion sources per IMO 2015 standards. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98% of sulfur in the fuel is oxidized to SO2 (MW = 32 g/mol) and 2% of sulfur in the fuel is oxidized to H2SO4 (MW = 98 g/mol) based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

[5] Conservatively based on AP-42 Chapter 3, Table 3.4-2, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

Normal Operations Emission Calculations

BMOP - Platform Diesel Generators

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
Acetaldehyde	AP-42	[6], [7]	7.67E-04	lb/MMBtu	2.42E-03	1.21E-04
Acrolein	AP-42	[6], [7]	9.25E-05	lb/MMBtu	2.91E-04	1.46E-05
Benzene	AP-42	[6], [7]	9.33E-04	lb/MMBtu	2.94E-03	1.47E-04
1,3-Butadiene	AP-42	[6], [7]	3.91E-05	lb/MMBtu	1.23E-04	6.16E-06
Formaldehyde	AP-42	[6], [7]	1.18E-03	lb/MMBtu	3.72E-03	1.86E-04
Toluene	AP-42	[6], [7]	4.09E-04	lb/MMBtu	1.29E-03	6.44E-05
Xylenes	AP-42	[6], [7]	2.85E-04	lb/MMBtu	8.98E-04	4.49E-05
Total PAH	AP-42	[6], [7]	1.68E-04	lb/MMBtu	5.29E-04	2.65E-05
Total VOC HAPs					**1.22E-02**	**6.10E-04**

[6] Emission factors based on AP-42, Chapter 3, Table 3.3-2, Speciated Organic Compound Emission Factors for Uncontrolled Stationary Diesel Engines (October 1996).

[7] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
CO_2	EPA	[8], [11]	73.96	kg/MMBtu	514	25.7
CH_4	EPA	[9], [11]	3.00E-03	kg/MMBtu	2.08E-02	1.04E-03
N_2O	EPA	[9], [11]	6.00E-04	kg/MMBtu	4.17E-03	2.08E-04
CO_2e	EPA	[10]	--	--	**515**	**25.8**

[8] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[9] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[10] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

[11] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Normal Operations Emission Calculations

BMOP - Platform B Cranes

Engine Rating [1]	=	354	kW
	=	475	HP
Total Operating Time [1]	=	4,380	hrs/yr
Operating Load [1]	=	100%	
Total Number of Gen Sets [1]	=	2	
Fuel Type [1]	=	Diesel	
Average Brake-Specific Fuel Consumption [2]	=	7,000	Btu/HP-hr
Average Higher Heating Value (HHV) [2]	=	19,300	Btu/lb
Average Heat Input Rate	=	3.33	MMBtu/hr

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions from 1 Engine	Annual Emissions from 1 Engine	Hourly Emissions from All Engines	Annual Emissions from All Engines
			Value	Units	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
$PM_{Filterable}$	EPA	[3], [4]	3.00E-02	g/kW-hr	0.02	0.05	0.05	0.10
$PM_{10, Filterable}$	EPA	[3], [4]	3.00E-02	g/kW-hr	0.02	0.05	0.05	0.10
$PM_{2.5, Filterable}$	EPA	[3], [4]	3.00E-02	g/kW-hr	0.02	0.05	0.05	0.10
$PM_{Condensable}$	AP-42	[5]	5.39E-05	lb/HP-hr	2.56E-02	5.61E-02	0.05	0.11
NO_x	EPA	[3]	0.60	g/kW-hr	0.47	1.03	0.94	2.05
SO_2	Fuel S Content	[6]	7.11E-04	lb/HP-hr	0.34	0.74	0.68	1.48
CO	EPA	[3]	3.5	g/kW-hr	2.73	5.99	5.47	11.97
VOC	EPA	[3]	0.285	g/kW-hr	0.22	0.49	0.45	0.97
H_2SO_4	Fuel S Content	[6]	2.22E-05	lb/HP-hr	1.06E-02	2.31E-02	2.11E-02	4.62E-02

[1] Based on current project design specifications, provided by BMOP.

[2] Based on AP-42 Chapter 3, Table 3.3-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines (October 1996).

[3] Per 40 CFR 60.4204(b) and Table 1 of 40 CFR 1039.101. Per 40 CFR 1039.101(e), emissions of PM, NO_X, and VOC are multiplied by the appropriate NTE multiplier.

[4] Conservatively assume $PM_{10} = PM_{2.5}$.

[5] Conservatively based on AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[6] A sulfur content of 0.1% is used for all diesel combustion sources per IMO 2015 standards. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98% of sulfur in the fuel is oxidized to SO2 (MW = 32 g/mol) and 2% of sulfur in the fuel is oxidized to H2SO4 (MW = 98 g/mol) based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

Normal Operations Emission Calculations

BMOP - Platform B Cranes

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions from 1 Engine	Annual Emissions from 1 Engine	Hourly Emissions from All Engines	Annual Emissions from All Engines
			Value	Units	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
Acetaldehyde	AP-42	[7], [8]	7.67E-04	lb/MMBtu	2.55E-03	5.59E-03	5.10E-03	1.12E-02
Acrolein	AP-42	[7], [8]	9.25E-05	lb/MMBtu	3.08E-04	6.74E-04	6.15E-04	1.35E-03
Benzene	AP-42	[7], [8]	9.33E-04	lb/MMBtu	3.10E-03	6.79E-03	6.20E-03	1.36E-02
1,3-Butadiene	AP-42	[7], [8]	3.91E-05	lb/MMBtu	1.30E-04	2.85E-04	2.60E-04	5.69E-04
Formaldehyde	AP-42	[7], [8]	1.18E-03	lb/MMBtu	3.92E-03	8.59E-03	7.85E-03	1.72E-02
Toluene	AP-42	[7], [8]	4.09E-04	lb/MMBtu	1.36E-03	2.98E-03	2.72E-03	5.96E-03
Xylenes	AP-42	[7], [8]	2.85E-04	lb/MMBtu	9.48E-04	2.08E-03	1.90E-03	4.15E-03
Total PAH	AP-42	[7], [8]	1.68E-04	lb/MMBtu	5.59E-04	1.22E-03	1.12E-03	2.45E-03
Total VOC HAPs					**1.29E-02**	**2.82E-02**	**2.58E-02**	**5.64E-02**

[7] Emission factors based on AP-42, Chapter 3, Table 3.3-2, Speciated Organic Compound Emission Factors for Uncontrolled Stationary Diesel Engines (October 1996).

[8] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions from 1 Engine	Annual Emissions from 1 Engine	Hourly Emissions from All Engines	Annual Emissions from All Engines
			Value	Units	(lb/hr)	(tons/yr)	(lb/hr)	(tons/yr)
CO_2	EPA	[9], [12]	73.96	kg/MMBtu	542.2	1,187.3	1,084.3	2,375
CH_4	EPA	[10], [12]	3.00E-03	kg/MMBtu	2.20E-02	4.82E-02	4.40E-02	9.63E-02
N_2O	EPA	[10], [12]	6.00E-04	kg/MMBtu	4.40E-03	9.63E-03	8.80E-03	1.93E-02
CO_2e	EPA	[11]	--	--	**544.0**	**1,191.4**	**1,088.0**	**2,383**

[9] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[10] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[11] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

[12] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Normal Operations Emission Calculations

BMOP - Platform B Firewater Pumps

Engine Rating [1]	=	485	kW
	=	650	HP
Total Operating Time [1]	=	100	hrs/yr
Operating Load [1]	=	100%	
Fuel Type [1]	=	Diesel	
Average Brake-Specific Fuel Consumption [2]	=	7,000	Btu/HP-hr
Average Higher Heating Value (HHV) [2]	=	19,300	Btu/lb
Average Heat Input Rate	=	4.55	MMBtu/hr

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
$PM_{Filterable}$	EPA	[3], [4]	0.15	g/HP-hr	0.21	0.01
$PM_{10, Filterable}$	EPA	[3], [4]	0.15	g/HP-hr	0.21	0.01
$PM_{2.5, Filterable}$	EPA	[3], [4]	0.15	g/HP-hr	0.21	0.01
$PM_{Condensable}$	AP-42	[5]	5.39E-05	lb/HP-hr	3.50E-02	1.75E-03
NO_x	EPA	[3]	3.00	g/HP-hr	4.30	0.21
SO_2	Fuel S Content	[6]	7.11E-04	lb/HP-hr	0.46	0.02
CO	EPA	[3]	2.60	g/HP-hr	3.73	0.19
VOC	EPA	[3]	3.00	g/HP-hr	4.30	0.21
H_2SO_4	Fuel S Content	[6]	2.22E-05	lb/HP-hr	1.44E-02	7.22E-04

[1] Based on current project design specifications, provided by BMOP.

[2] Based on AP-42 Chapter 3, Table 3.3-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines (October 1996).

[3] Per 40 CFR 60.4205(c) and Table 4 of NSPS Subpart IIII. Conservatively assume that NO_X and VOC emissions are equivalent to the NMHC + NO_X emissions limit.

[4] Conservatively assume $PM_{10} = PM_{2.5}$.

[5] AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[6] A sulfur content of 0.1% is used for all diesel combustion sources per IMO 2015 standards. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98% of sulfur in the fuel is oxidized to SO2 (MW = 32 g/mol) and 2% of sulfur in the fuel is oxidized to H2SO4 (MW = 98 g/mol) based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

Normal Operations Emission Calculations

BMOP - Platform B Firewater Pumps

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
Acetaldehyde	AP-42	[7], [8]	2.52E-05	lb/MMBtu	1.15E-04	5.73E-06
Acrolein	AP-42	[7], [8]	7.88E-06	lb/MMBtu	3.59E-05	1.79E-06
Benzene	AP-42	[7], [8]	7.76E-04	lb/MMBtu	3.53E-03	1.77E-04
Formaldehyde	AP-42	[7], [8]	7.89E-05	lb/MMBtu	3.59E-04	1.79E-05
Toluene	AP-42	[7], [8]	2.81E-04	lb/MMBtu	1.28E-03	6.39E-05
Xylenes	AP-42	[7], [8]	1.93E-04	lb/MMBtu	8.78E-04	4.39E-05
Total PAH	AP-42	[7], [8]	2.12E-04	lb/MMBtu	9.65E-04	4.82E-05
Total VOC HAPs					**7.16E-03**	**3.58E-04**

[7] Emission factors based on AP-42, Chapter 3, Table 3.4-3, Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[8] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Normal Operations Emission Calculations

BMOP - Platform B Firewater Pumps

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
CO_2	EPA	[9], [12]	73.96	kg/MMBtu	741.9	37.09
CH_4	EPA	[10], [12]	3.00E-03	kg/MMBtu	3.01E-02	1.50E-03
N_2O	EPA	[10], [12]	6.00E-04	kg/MMBtu	6.02E-03	3.01E-04
CO_2e	EPA	[11]	--	--	**744.4**	**37.22**

[9] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[10] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[11] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

[12] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Normal Operations Emission Calculations

BMOP - Platform C Firewater Pumps

Engine Rating [1]	=	485	kW
	=	650	HP
Total Operating Time [1]	=	100	hrs/yr
Operating Load [1]	=	100%	
Fuel Type [1]	=	Diesel	
Average Brake-Specific Fuel Consumption [2]	=	7,000	Btu/HP-hr
Average Higher Heating Value (HHV) [2]	=	19,300	Btu/lb
Average Heat Input Rate	=	4.55	MMBtu/hr

Criteria Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
$PM_{Filterable}$	EPA	[3], [4]	0.15	g/HP-hr	0.21	0.01
$PM_{10, Filterable}$	EPA	[3], [4]	0.15	g/HP-hr	0.21	0.01
$PM_{2.5, Filterable}$	EPA	[3], [4]	0.15	g/HP-hr	0.21	0.01
$PM_{Condensable}$	AP-42	[5]	5.39E-05	lb/HP-hr	3.50E-02	1.75E-03
NO_x	EPA	[3]	3.00	g/HP-hr	4.30	0.21
SO_2	Fuel S Content	[6]	7.11E-04	lb/HP-hr	0.46	0.02
CO	EPA	[3]	2.60	g/HP-hr	3.73	0.19
VOC	EPA	[3]	3.00	g/HP-hr	4.30	0.21
H_2SO_4	Fuel S Content	[6]	2.22E-05	lb/HP-hr	1.44E-02	7.22E-04

[1] Based on current project design specifications, provided by BMOP.

[2] Based on AP-42 Chapter 3, Table 3.3-1, Emission Factors for Uncontrolled Gasoline and Diesel Industrial Engines (October 1996).

[3] Per 40 CFR 60.4205(c) and Table 4 of NSPS Subpart IIII. Conservatively assume that NO_X and VOC emissions are equivalent to the NMHC + NO_X emissions limit.

[4] Conservatively assume $PM_{10} = PM_{2.5}$.

[5] AP-42 Chapter 3, Table 3.4-1, Emission Factors for Large Stationary Diesel and all Stationary Dual-fuel Engines (October 1996).

[6] A sulfur content of 0.1% is used for all diesel combustion sources per IMO 2015 standards. Therefore, emissions have been calculated based on a maximum sulfur content of 1000 ppm in diesel fuel assuming that 98% of sulfur in the fuel is oxidized to SO2 (MW = 32 g/mol) and 2% of sulfur in the fuel is oxidized to H2SO4 (MW = 98 g/mol) based on Draft Regulatory Impact Analysis: Control of Emissions from Nonroad Diesel Engines, EPA420-R-03-008, April 2003.

Normal Operations Emission Calculations

BMOP - Platform C Firewater Pumps

Hazardous Air Pollutants

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
Acetaldehyde	AP-42	[7], [8]	2.52E-05	lb/MMBtu	1.15E-04	5.73E-06
Acrolein	AP-42	[7], [8]	7.88E-06	lb/MMBtu	3.59E-05	1.79E-06
Benzene	AP-42	[7], [8]	7.76E-04	lb/MMBtu	3.53E-03	1.77E-04
Formaldehyde	AP-42	[7], [8]	7.89E-05	lb/MMBtu	3.59E-04	1.79E-05
Toluene	AP-42	[7], [8]	2.81E-04	lb/MMBtu	1.28E-03	6.39E-05
Xylenes	AP-42	[7], [8]	1.93E-04	lb/MMBtu	8.78E-04	4.39E-05
Total PAH	AP-42	[7], [8]	2.12E-04	lb/MMBtu	9.65E-04	4.82E-05
Total VOC HAPs					**7.16E-03**	**3.58E-04**

[7] Emission factors based on AP-42, Chapter 3, Table 3.4-3, Speciated Organic Compound Emission Factors for Large Uncontrolled Stationary Diesel Engines (October 1996).

[8] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

Normal Operations Emission Calculations

BMOP - Platform C Firewater Pumps

Greenhouse Gases

Pollutant	Emission Factor Basis		Emission Factor		Hourly Emissions	Annual Emissions
			Value	Units	(lb/hr)	(tons/yr)
CO_2	EPA	[9], [12]	73.96	kg/MMBtu	741.9	37.09
CH_4	EPA	[10], [12]	3.00E-03	kg/MMBtu	3.01E-02	1.50E-03
N_2O	EPA	[10], [12]	6.00E-04	kg/MMBtu	6.02E-03	3.01E-04
CO_2e	EPA	[11]	--	--	**744.4**	**37.22**

[9] Emission factor based on 40 CFR 98 Subpart C, Table C-1 Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel. The emission factor for Distillate Fuel Oil No. 2 was used to calculate emissions.

[10] Emission factors based on 40 CFR 98 Subpart C, Table C-2 Default CH_4 and N_2O Emission Factors for Various Types of Fuel. The emission factor for petroleum (All types in table C-1) was used to calculate emissions.

[11] CH4, CO2 and N2O are included in the emissions of CO2 equivalent (CO2e), weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

[12] An average BSFC of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr to calculate emissions.

BMOP - Deepwater Port WC509 platform
Tank Emissions

Platform	Tank ID	Roof Type	Standing Losses (tpy)	Working Losses (tpy)	Total VOC Losses (tpy)	Total HAP Losses (tpy)
WC509	Aviation Fuel Storage[1]	Horizontal Tank	2.90E-04	2.22E-04	5.12E-04	7.65E-05
	Crane Diesel Tank No. 1[2]	FRT (no floating roof)	4.14E-04	1.52E-03	1.93E-03	2.65E-04
	Crane Diesel Tank No. 2[2]	FRT (no floating roof)	4.14E-04	1.52E-03	1.93E-03	2.65E-04
	Primary Diesel Storage Tank[2]	Horizontal Tank	2.23E-03	6.28E-03	0.01	1.17E-03
	Surge Tank	Horizontal Tank	3.57	0.17	3.73	0.07
				Totals:	**3.74**	**0.07**

[1] TankESP default Jet Kerosene is used as a product for this tank.
[2] TankESP default Diesel stock is used as product for this tank.

BMOP - Deepwater Port WC509 platforn
Tank Emissions

Platform	Tank ID	HAP Emissions (lb/yr)										
		Benzo(g,h,i)perylene	Biphenyl	Cumene	Cyclohexane	Ethylcyclohexane	Hexanol (1)	Neopentane {dimethylpropane (2,2)}	Pentane (n-)	Toluene diisocyanate	Trimethylbenzene (1,3,5)	Xylene (m-)
WC509	Aviation Fuel Storage[1]	6.91E-03	2.41E-16	-	-	2.07E-02	1.39E-02	3.31E-04	3.58E-14	6.70E-02	-	4.42E-02
	Crane Diesel Tank No. 1[2]	7.71E-03	2.95E-15	-	-	1.18E-02	1.55E-03	1.74E-03	6.41E-13	8.98E-02	1.88E-01	2.30E-01
	Crane Diesel Tank No. 2[2]	7.71E-03	2.95E-15	-	-	1.18E-02	1.55E-03	1.74E-03	6.41E-13	8.98E-02	1.88E-01	2.30E-01
	Primary Diesel Storage Tank[2]	3.39E-02	1.33E-14	-	-	5.21E-02	6.81E-03	7.69E-03	2.88E-12	3.95E-01	8.27E-01	1.01
	Surge Tank	33.2	9.34E-15	2.54E-01	39.8	2.13	35.5	5.13E-03	9.94E-12	16.3	3.69E-01	6.53
		33.28	**2.87E-14**			**2.23**	**35.48**	**1.66E-02**	**1.41E-11**	**16.92**	**1.57**	**8.05**

[1] TankESP default Jet Kerosene is used as a product for t
[2] TankESP default Diesel stock is used as product for this

BMOP - Deepwater Port WC509 platform
Fugitive Emissions

Source	Contents	Platform	Service	Equipment Counts: Valves	Flanges/Connectors	Pumps	Vapor/Gas Relief Valves	Compressors	Process Drains	Sampling Connections	Total VOC[1] (lb/hr)	Total VOC[2] (tpy)	Total HAP[3] (lb/hr)	Total HAP[2] (tpy)	Total H_2S[4] (lb/hr)	Total H_2S[2,4] (tpy)	Total CO_2e[5] (lb/hr)	Total CO_2e[2] (tpy)
Fuel Gas Scrubber	Natural Gas	509B	Gas/Vapor	21	22	0	2	0	4	0	0.07	0.30	6.74E-03	0.03	0	0	17.51	76.68
Condensate Pump No. 1	Natural Gas	509A	Gas/Vapor	20	15	1	1	0	2	0	0.05	0.22	4.86E-03	0.02	0	0	12.62	55.28
Condensate Pump No. 2	Natural Gas	509A	Gas/Vapor	20	15	1	1	0	2	0	0.05	0.22	4.86E-03	0.02	0	0	12.62	55.28
Pig Launcher No. 1 (Gas Export)	Natural Gas	509A	Gas/Vapor	63	126	0	0	0	8	8	0.13	0.58	0.01	0.06	0	0	33.84	148.21
Pig Launcher No. 2 (Gas Export)	Natural Gas	509A	Gas/Vapor	63	126	0	0	0	8	8	0.13	0.58	0.01	0.06	0	0	33.84	148.21
Pig Receiver (Oil Import)	Crude Oil	509A	Light Liquid	9	17	0	0	0	4	0	0.10	0.45	5.82E-03	0.03	1.34E-03	1.98E-04	0	0
Crude Oil Mainline	Crude Oil	509A	Light Liquid	9	17	0	0	0	4	0	0.10	0.45	5.82E-03	0.03	1.34E-03	1.98E-04	0	0
Oil Meter Skid	Crude oil	509B	Light Liquid	52	105	0	0	0	6	1	0.57	2.50	0.03	0.14	7.39E-03	1.09E-03	0	0
Meter Prover Skid	Crude Oil	509B	Light Liquid	8	16	0	0	0	1	0	0.08	0.36	4.65E-03	0.02	1.07E-03	1.58E-04	0	0
Pig Launcher No. 1 (Export to VLCC)	Crude Oil	509B	Light Liquid	18	34	0	0	0	8	0	0.21	0.91	0.01	0.05	2.69E-03	3.95E-04	0	0
Pig Launcher No. 2 (Export to VLCC)	Crude Oil	509B	Light Liquid	18	34	0	0	0	8	0	0.21	0.91	0.01	0.05	2.69E-03	3.95E-04	0	0
CALM Buoy #1	Crude Oil	--	Light Liquid	20	50	0	0	0	0	0	0.20	0.89	0.01	0.05	2.63E-03	3.87E-04	0	0
CALM Buoy #2	Crude Oil	--	Light Liquid	20	50	0	0	0	0	0	0.20	0.89	0.01	0.05	2.63E-03	3.87E-04	0	0
Surge Relief Valve Skid	Crude Oil	509B	Light Liquid	20	18	0	0	0	2	0	0.19	0.85	0.01	0.05	2.52E-03	3.71E-04	0	0
Surge Tank	Crude Oil	509B	Light Liquid	12	22	2	0	0	1	0	0.21	0.92	0.01	0.05	2.71E-03	3.99E-04	0	0
Surge Tank Pump No. 1	Crude Oil	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	2.43E-03	0.01	5.61E-04	8.26E-05	0	0
Surge Tank Pump No. 2	Crude Oil	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	2.43E-03	0.01	5.61E-04	8.26E-05	0	0
Sump System No. 1	Crude Oil	509B	Light Liquid	15	32	2	0	0	3	0	0.25	1.09	0.01	0.06	3.22E-03	4.74E-04	0	0
Sump System No. 2	Crude Oil	509C	Light Liquid	15	32	2	0	0	3	0	0.25	1.09	0.01	0.06	3.22E-03	4.74E-04	0	0
Firewater Pump No. 1	Diesel Fuel	509B	Light Liquid	5	6	0	0	0	1	0	0.05	0.22	7.04E-03	0.03	0	0	0	0
Firewater Pump No. 2	Diesel Fuel	509C	Light Liquid	5	6	0	0	0	1	0	0.05	0.22	7.04E-03	0.03	0	0	0	0
Air Compressor No. 1	Diesel Fuel	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	5.96E-03	0.03	0	0	0	0
Air Compressor No. 2	Diesel Fuel	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	5.96E-03	0.03	0	0	0	0
Crane Diesel Tank No. 1	Diesel Fuel	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	5.96E-03	0.03	0	0	0	0
Platform Crane No. 1	Diesel Fuel	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	5.96E-03	0.03	0	0	0	0
Platform Crane No. 2	Diesel Fuel	509B	Light Liquid	4	8	0	0	0	1	0	0.04	0.19	5.96E-03	0.03	0	0	0	0
Diesel Transfer Skid	Diesel Fuel	509B	Light Liquid	18	30	2	0	0	1	0	0.27	1.17	0.04	0.16	0	0	0	0
LQ Crane	Diesel Fuel	509C	Light Liquid	18	30	2	0	0	1	0	0.27	1.17	0.04	0.16	0	0	0	0
Diesel Transfer Pump No. 1	Diesel Fuel	509B	Light Liquid	18	30	2	0	0	1	0	0.27	1.17	0.04	0.16	0	0	0	0
Diesel Transfer Pump No. 2	Diesel Fuel	509B	Light Liquid	18	30	2	0	0	1	0	0.27	1.17	0.04	0.16	0	0	0	0
Gas Generator No. 1	Natural Gas	509B	Gas/Vapor	10	11	0	0	0	2	0	0.01	0.07	1.47E-03	6.44E-03	0	0	3.82	16.72
Gas Generator No. 2	Natural Gas	509B	Gas/Vapor	10	11	0	0	0	2	0	0.01	0.07	1.47E-03	6.44E-03	0	0	3.82	16.72
Emergency Diesel Generator	Diesel Fuel	509B	Light Liquid	5	6	0	0	0	1	0	0.05	0.22	7.04E-03	0.03	0	0	0	0
Knockout System	Natural Gas	509B	Gas/Vapor	30	40	0	2	0	2	0	0.08	0.36	8.20E-03	0.04	0	0	21.30	93.30
Fuel Gas Skid	Natural Gas	509B	Gas/Vapor	68	81	0	6	0	13	5	0.23	1.00	0.02	0.10	0	0	58.66	256.92
Aviation Refueling System No. 1	Aviation Fuel	509B	Light Liquid	6	20	1	0	0	1	0	0.11	0.49	0.11	0.49	0	0	0	0
Aviation Refueling System No. 2	Aviation Fuel	509C	Light Liquid	6	20	1	0	0	1	0	0.11	0.49	0.11	0.49	0	0	0	0
Three (3) VCU Systems	Natural Gas	509A	Gas/Vapor	36	72	0	3	4	4	3	0.29	1.28	0.03	0.13	0	0	74.67	327.04
High Pressure Flare Scrubber and Pump	Natural Gas	VBT	Gas/Vapor	2	4	1	0	0	1	0	7.32E-03	0.03	7.23E-04	3.17E-03	0	0	1.88	8.22
Low Pressure Flare	Natural Gas	VBT	Gas/Vapor	2	4	1	0	0	1	0	7.32E-03	0.03	7.23E-04	3.17E-03	0	0	1.88	8.22
											5.41	23.69	0.68	2.96	0.03	5.09E-03	276.4	1,211

[1] Emission factors based on EPA's Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017 https://www3.epa.gov/ttnchie1/efdocs/equiplks.pdf
[2] Based on continous operation (e.g. 8,760 hours per year).
[3] HAP emissions are based on the speciation of:
- Natural Gas Composition and Properties based on an April 13, 2020 sample at WC509.
- Diesel fuel HAP content consistent with tank emissions speciation.
- Crude Oil speciation per the maximum mass %, vapor values calculated for crude oil loading emissions.

[4] H2S emissions are calculated based on the mass balance and liquid H2S parition factors from the Petroleum Processing Handbook, McGraw-Hill, New York, Figure 12-71, page 12-93. Short-term and annual H2S consistent with loading emissions.
[5] CO2 and CH4 speciation of natural gas based on an April 13, 2020 sample at WC509. CH4 and CO2 CO2e, weighted according to their global warming potential (GWP). The GWP was obtained from Table A-1 to Subpart A of Part 98.

APPENDIX D. CERTIFICATE OF GOOD STANDING

State of Louisiana Secretary of State

COMMERCIAL DIVISION
225.925.4704

Fax Numbers
225.932.5317 (Admin. Services)
225.932.5314 (Corporations)
225.932.5318 (UCC)

Name	Type	City	Status
ENERGY TRANSFER PARTNERS, L.L.C.	Limited Liability Company (Non-Louisiana)	WILMINGTON	Active

Previous Names

Business: ENERGY TRANSFER PARTNERS, L.L.C.
Charter Number: 41690424Q
Registration Date: 11/7/2014
Domicile Address
2711 CENTERVILLE ROAD, SUITE 400
WILMINGTON, DE 19808
Mailing Address
8801 S YALE AVE., SUITE 310
TULSA, OK 74137
Principal Business Office
8111 WESTCHESTER DRIVE
STE 600
DALLAS, TX 75225
Registered Office in Louisiana
501 LOUISIANA AVENUE
BATON ROUGE, LA 70802
Principal Business Establishment in Louisiana
501 LOUISIANA AVE
BATON ROUGE, LA 708026129

Status

Status: **Active**
Annual Report Status: **In Good Standing**
Qualified: 11/7/2014
Last Report Filed: 10/10/2022
Type: Limited Liability Company (Non-Louisiana)

Registered Agent(s)

Agent: CORPORATION SERVICE COMPANY
Address 1: 501 LOUISIANA AVENUE
City, State, Zip: BATON ROUGE, LA 70802
Appointment Date: 11/7/2014

Officer(s)

Additional Officers: No

Officer:	KELCY WARREN
Title:	Manager
Address 1:	8111 WESTCHESTER DRIVE, STE 600
City, State, Zip:	DALLAS, TX 75225

Officer:	MARSHALL MCCREA
Title:	Manager
Address 1:	800 E SONTERRA BLVD
City, State, Zip:	SAN ANTONIO, TX 78258

Officer:	MATTHEW RAMSEY
Title:	Manager
Address 1:	8111 WESTCHESTER DRIVE, STE 600
City, State, Zip:	DALLAS, TX 75225

Amendments on File (1)

Description	Date
Foreign LLC Statement of Change	12/28/2015

Print