Prepared for:

Homeland Guards
Box 4452
4 Ha-Shezif Street
30900 Zichron Yaacov
Israel

Prepared by:

Amnon Bar-Ilan, Shari Libicki
Ramboll US Corporation
7250 Redwood Blvd., Suite 105
Novato, California 94945

April 2019
1690010952

Leviathan Gas Platform

Emission Permit Review

Contents

TABLES

FIGURES

1.0 Introduction

Noble Energy Inc. has proposed to build an offshore natural gas production platform in the Mediterranean Sea, located approximately 9.7 km west of the coast of Israel near the city of Haifa. The platform is designed to initially produce approximately 1,200 standard million cubic feet of natural gas per day (approximately 1.4 million cubic meters per hour) during Phase I of operation, with an additional 900 standard million cubic feet of natural gas per day (approximately 1 million cubic meters per hour) during Phase II of operation. In addition the platform will produce approximately 570 cubic meters per day of condensate during Phase I of operation, increasing to approximately 1,000 cubic meters per day of condensate during Phase II of operation. The proposed Leviathan platform will produce from the Leviathan Gas Field in the Mediterranean Basin, located 125 km east of Haifa and 35 km east of the "Tamar" gas field. The depth of the water is between 1600 -1750 meters.

Noble Energy submitted a “Request for Emission Permit” to the Israel Ministry of Environmental Protection in the fall of 2018, and subsequently submitted a revised Request for Emission Permit in January 2019. This report refers only to the revised Request for Emission Permit submitted in January 2019.

Homeland Guards, a non-profit organization based in Zichron Yaacov Israel, contracted with Ramboll Corp. to review the revised Request for Emission Permit and provide comments on the accuracy, completeness and reasonableness of the permit request.

1.1 Leviathan Platform Overview

The Leviathan Platform is proposed to be situated 9.7km east of the Israeli shore in the Mediterranean Sea, where the depth of the water is 86 meters. The platform will be constructed such that a jacket will be bolted into the sea floor, upon which the remainder of the platform will rest. The platform is proposed to be 9,216 m^2 in area, rising in three levels to an upper deck height of 57 m above sea level. The platform will consist of thermal power systems providing more than 50 megawatts of heat and electricity to power the platform and its associated systems. Processes on the platform will include separation of gas and liquids, drying and compression of natural gas, stabilization of condensate liquids, reclamation of venting/waste gas streams, treatment of produced water, and various systems to produce electricity, and transport of hazardous waste products. As noted above, the proposed project would initially produce approximately 1,200 standard million cubic feet of natural gas per day and 570 cubic meters of condensate per day in Phase I, rising to 2,100 standard million cubic feet of natural gas per day and 1,000 cubic meters of condensate per day in Phase II.

Emissions from the platform consist of combustion sources and venting/fugitive sources. Primary combustion sources include gas turbines for power and heat, heaters for separation and treatment, and flares/combustors for waste gas destruction. Primary venting/fugitive sources include fugitive emissions from pipeline components, venting from pipelines and from storage tanks. Emissions of NOx, VOC, SOx, and CO (“criteria pollutants”) are expected, as well as emissions of hazardous air pollutants (HAPs) such as benzene. The primary focus of this review is on emissions of VOCs, although emissions of other pollutants are discussed.

1.2 Emissions Permit Review

Homeland Guards requested that Ramboll conduct a review of the request for emissions permit, with a focus on reviewing the reasonableness, accuracy and completeness of information in the permit with a focus on emissions of VOCs. Ramboll's review includes reviewing the facility and equipment list, schematics and flow diagrams of the operation of the facility, assumptions, inputs and modeling tools used to estimate emissions from facilities and equipment on the platform, and the quantitative estimates of these emissions themselves.

In conducting this review, Ramboll reviewed the following documents associated with the request for emission permit:

CH-1.docx
CH-2.docx
2.1.6 Discharge Block Diagram.pdf
4501.5 – Expected Emissions_Efficiency.pdf
LPP-TS-FDE-PRS-PFD-0050.pdf
LPP-TS-FLP-MEC-DAS-4000.pdf
LPP-TS-PER-PRS-DBK-0005.pdf
LPP-TS-PER-PRS-PFD-0010.pdf
LPP-TS-PER-PRS-PFD-0020.pdf
Form 2.1.1.pdf
Form 2.1.2.pdf
Form 2.1.3.pdf
Form 2.1.4.1 – NR.pdf
Form 2.1.4.2.pdf
Form 2.1.4.3.pdf
Form 2.1.5.1 – NR.pdf
Form 2.1.5.2 – NR.pdf
Form 2.1.6.1.pdf
Form 2.1.6.2 – NR.pdf
Form 2.1.7 OD.pdf
Form 2.1.7 PW.pdf
Form 2.1.8.pdf
Form 2.1.9.1 - NR.pdf
Form 2.1.9.2.pdf
Form 2.1.10.pdf
Form 2.2.1.pdf
Form 2.2.2 – NR.pdf
Form 2.3.pdf
Chapter 3-6.docx
API-2516 Evaporation Loss from Low-Pressure Tanks.pdf
LEV – Benzene JAN2019.pdf
LPP-TS-FDE-PRS-RPT-0020 1-7.pdf
Methanol Storage Vessel Emissions 4Dec2018.pdf
TANKS SOFTWARE RESULTS.pdf
Form 3.1.2.1 NR.pdf
Form 3.1.2.2.pdf
Form 3.2.1.pdf
Form 3.2.2 NR.pdf
Form 3.2.3 NR.pdf
Form 3.3 Condensate.pdf
Form 3.3 Methanol.pdf
Form 3.4.pdf
Form 3.5.pdf
Form 3.12 am.pdf
BAT tables ENE BREF.pdf
BAT tables ESB BREF.pdf
BAT tables LCP BREF.pdf
BAT tables REF BREF.pdf
Leviathan Valve Standards Letter.pdf
Summary table of standards.pdf
Form 4.3.1.pdf
Form 4.3.2.pdf
CH7 (1).docx
Form 2.1.4.2.xlsx
Form 7.1.2.xlsx
Form 7.1.4.1.xlsx
Form 7.2.4.xlsx
Form 7.2.6.xlsx
Form 7.2.10.xlsx
Form 7.3.2 NO2.xlsx
Form 7.3.2 NOx.xlsx
Form 7.3.2 PM.xlsx
Form 7.3.2 PM10.xlsx
Form 7.3.2 SO2.xlsx
Form 7.3.3.xlsx

In addition, Ramboll reviewed CALPUFF dispersion modeling results for NO_2 (Hourly, Yearly, Max Yearly), NOx (Hourly, Daily), PM10 (Daily, Yearly), SO_2 (Hourly, Daily, Yearly), and TSP (3-Hour, Daily, Yearly).

1.3 Ramboll Company Profile

Ramboll is a leading engineering, design and consultancy company employing 13,000 experts. Our presence is global with especially strong representation in the Nordics, UK, North America, Continental Europe, Middle East and Asia Pacific.

Ramboll's Environment & Health practice is globally recognized, with 2,100 expert who have earned a reputation for technical and scientific excellence, innovation, and client service. Advances in science and technology and evolving regulatory, legal and social pressures create increasingly complex challenges for Ramboll's clients. Ramboll evolves to keep pace with these changes – by adding new services, contributing to scientific advances and expanding geographically.

Ramboll offers a comprehensive array of air quality management services in the oil and gas sector, including facility-based services, strategic planning, and litigation support. Ramboll's principal and senior air sciences staff is internationally recognized in all areas relevant to comprehensive air quality practices. Senior staff members are supported by scientists and engineers with capabilities that encompass the entire range of air quality services.

Ramboll's project experience ranges from site-specific monitoring and permitting to regional-scale air quality modeling and evaluation of critical oil and gas industry air quality issues. These projects have provided the basis for facility permitting programs, worker safety evaluations and litigation. Ramboll's regional-scale air modeling efforts form a critical basis for the current understanding regarding potential air quality impacts associated with some of the more active unconventional oil and gas basins. Ramboll has performed recent basin wide assessments in the Haynesville, Eagleford and the Western Regional shale oil and gas producing basins. Ramboll has conducted a wide range of projects in the oil and gas industry, including:

- Ramboll staff participated in the development of an Exploration Plan & Environmental Impact Assessment, for Arctic offshore oil and gas development project. Staff was responsible for overall quality and control of draft EIA and EP, working as a team member with nationwide subject matter experts, facilitating preparation of the Draft EP and EIA, and conducting senior technical review. The work also included researching oil spill response logistics and techniques in remote arctic environment, and hazardous waste management options in remote camps and support vessels.
- Ramboll staff served in Program Management for the Alaska Pipeline Project, ExxonMobil Development Co. (EMDC) (2009-present). This 48-in. pipeline was proposed for export of Alaska North Slope natural gas from Prudhoe Bay through Canada to the Lower-48, or to tidewater Alaska for shipment as LNG. Staff served as Program Manager for Environmental & Regulatory Support Services for the Alaska portion of the pipeline. Staff was retained by EMDC to evaluate environmental study plans and to develop strategies for environmental permitting and compliance.
- Since 2009, Ramboll has provided technical support to Chesapeake Energy on a variety of air quality issues of importance to the industry. This work includes advising Chesapeake on how to model reciprocating internal combustion engines for comparison of impacts to the US 1-hour NO_2 ambient air quality standard.

2.0 Comments on the Request for Emission Permit

As noted above, Ramboll reviewed the request for emission permit from the standpoint of reasonableness of assumptions, accuracy and completeness. Ramboll also reviewed the overall quantitative emission inventory for the Leviathan platform in comparison to other major offshore platforms in the U.S. Gulf of Mexico. We first note specific comments on various aspects of the request for emission permit, and then discuss the overall platform emissions in the context of other major offshore oil and gas platforms.

2.1 Specific Comments

Specific comments on various aspects of the request for emission permit are summarized below. These comments are based on a review of the documents described in Section 1.2 above.

1. The provided process description and process diagrams, Chapter 2, included "LP Fuel Gas and LP Flare Systems" which describes the lines going to the fuel gas or flare system. We recommend the Ministry of Environmental Protection or other regulatory agency to closely monitor the Fuel Gas Recovery Unit system reliability. Although we have seen systems like this work for oil treatment systems, we have never seen them deployed for gas systems. This system is critical to the destruction of pollutants and the processing of waste gas throughout the life of the project; therefore, particularly during the initial phase of operation of the platform, it is recommended that such a system be instrumented to provide continuous monitoring of its operation and any upset conditions be addressed immediately. Upset conditions could include overpressurization of a vessel or a line, unlit or non-operational flare, operational errors such as hatches left open, or other similar conditions. In the U.S. recent research has been focusing on these abnormal or upset conditions as a major source of emissions, and likely to drive the uneven distribution of emissions from well sites[1,2,3]. We note that the fuel gas system is designed to treat a number of waste gas streams. The request for emission permit includes a simulated composition of the fuel gas system, indicating that the fuel gas is suitable for combustion. However, no supporting information or backup documentation is provided for this simulated composition. It is recommended that such documentation be provided to confirm the suitability of the fuel gas for combustion. In addition, once in operation the flare should be monitored as per

---

[1] Zavala-Araiza, D., et al. (2015), Reconciling divergent estimates of oil and gas methane emissions, Proceedings of the National Academy of Sciences, 112, 51, 15597-15602, doi: www.pnas.org/cgi/doi/10.1073/pnas.1522126112.

[2] Schade, G. W., and G. Roest (2016), Analysis of non-methane hydrocarbon data from a monitoring station affected by oil and gas development in the Eagle Ford shale, Texas, *Elem. Sci. Anth.*, 4, 000,096, doi:10.12952/journal.elementa.000096.

[3] Lyon, D.R., et al. (2016), Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites, Environmental Science & Technology,2016, 50, 4877-4886, doi: 10.1021/acs.est.6b00705.

European Best Available Technology (BAT) requirements. These include monitoring of the mass flow rate and lower calorific value of the flare gas, and comparing of these measured values to the design requirements of the flare to guarantee the minimum combustion efficiency. The flare gas composition should be analyzed by periodic sampling, and records of this sampling taken and stored.

2. Maintenance, Startup and Shutdown (MSS) activity is increasingly being included in permits for oil and gas facilities in the U.S. MSS activities are not described in the request for emission permit, and we strongly recommend that such activities – including pipeline, vessel and compressor blowdowns – be included. Typically these types of MSS events are vented without routing to a control system, depending on the equipment type being vented, or the location of a piping component that needs to be removed. If not routed to a flaring or other control system, these would be considered "cold vents" and should be called out as such. These could include:

    a. Recompressor No. 1/2/3 blowdown activities – it is unclear from the description of processes in the request for emission permit where the gases and/or liquids are routed when blowing down any or all of the compressor stages. The request for emission permit should be revised to describe whether the gases and/or liquids are routed to lower pressure systems for recovery by pipeline, or whether the gases and/or liquids are routed to a flare for destruction.
    b. Line clearing and pigging – in Chapters 3-6, the request for emission permit explains that the well-to-platform and platform-to-shore pipelines will be purged with nitrogen prior to operational startup. However, no similar description is provided for pigging activities. It is recommended that the request for emission permit be revised to include nitrogen purging of the pig traps prior to pigging activities to eliminate VOC and HAP emissions from pigging activities. Gas and condensate pig launching activities are typically vented to atmosphere. It is important to identify where emissions from launching activities are routed, frequency of the activities (number of times per week or month), the size, pressure and temperature of the launcher. If not purged with nitrogen, there can be significant VOC and HAP emissions from pigging activities.
    c. Other vessel blowdown activities – it is unclear from the request for emission permit the frequency and types of other platform vessels that may need to be blown down for routine maintenance and cleaning. As noted above for pipeline components and pigging activities, vessel blowdowns may be significant VOC and HAP emissions sources.

   We note that the request for emission permit estimates various volumes of possible release rates, but does not provide documentation on how these release rates were determined. There is insufficient information for us to verify the release rate described in the request for emission permit.

3. Flaring efficiency for the fuel gas system has been described in the request for emission permit as 99% which is not a control efficiency value used in permitting in the U.S. Flare destruction efficiency is typically cited as either 95% or 98%. EPA's AP-42 compendium of emission factors references 98% destruction efficiency: "Properly operated flares achieve at least 98% destruction efficiency in the flare plume, meaning that hydrocarbon emissions amount to less than 2 percent of the

hydrocarbons in the gas stream.[4]" In the state of Colorado, the Colorado Department of Public Health and the Environment (CDPHE) requires that sources control emissions with at least a 95% control efficiency: "Sources are required to control emissions under Section XVII with a least a 95% control efficiency but also to use a combustion device designed to have a destruction efficiency of 98%. Why does the Division distinguish between the two percentages? Sources are required to meet a 95% control efficiency. The division requires that the combustion device used be designed to have a 98% destruction efficiency, because it recognizes that combustion devices designed to meet a 98% control efficiency may not actually meet this percentage in practice, given the variability of field conditions, downtime, etc.[5]" We recommend that the request for emission permit use at most a 98% destruction efficiency for the flare, consistent with most U.S. permits.

4. Support vessel activity has not been included in the request for emission permit. Support vessels could include marine vessels used to transport crew, barges used to transport crew and/or equipment, marine tankers, and helicopters. Individually these may not represent large sources of NOx, VOC, SOx, CO and HAPs, but without knowledge of support vessel activity (number of vessels, size, and frequency of visits) it is impossible to determine the potential magnitude of the collective emissions from these sources. In particular, Chapter 3-6 mentions that the platform is equipped for loading condensate to marine tankers but the emissions are not accounted for. The process diagrams in the request for emission permit do not show any lines for vapor recovery coming from marine tanker loading. These emissions should be included as part of the emissions quantification in the request for emission permit. Marine tanker loading short-term emissions can be substantial for VOC and BTEX.
5. Produced water treatment can produce VOC and HAPs emissions which need to be identified. Although concentrations of VOC in produced water can be low, the volume of water produced can result in significant emissions. The process diagrams in the request for emission permit do not indicate where emissions from produced water would be routed.
6. Gas and liquid composition data provided in the request for emission permit are not sufficiently detailed for us to conduct a full analysis. More information, including the point of sampling, pressure, temperature, heat content of the gas, specific gravity of the gas, molecular weight of the gas and compressibility factor, and C10+ properties of the liquid sample would need to be provided for a full analysis. This is a requirement in the U.S. for sampling that is submitted as part of any emissions permit[6]. In addition, any sample submitted in the U.S. for an emission permit must also include the date of the sample and the sampling company and contact.
7. However, we note that the gas and liquid composition do not seem to agree with each other: a much heavier gas sample is expected for a liquid sample with greater than 90% C8+. Nevertheless, both samples show presence of VOCs and VOC emissions would be expected from any gas vented to atmosphere.
8. Miscellaneous tank emissions were calculated with the software model Tanks 4.0 for tanks only storing chemicals needing to be used in the process (e.g. nafta as demulsifier, and isopropyl alcohol as coagulant), but flashing emissions are not calculated for these tanks. Flashing emissions occur when a rapid change of

[4] AP-42, Section 13.5 https://www3.epa.gov/ttn/chief/ap42/ch13/final/C13S05_02-05-18.pdf

[5] CDPHE https://www.colorado.gov/pacific/sites/default/files/AP-Memo-15-03-AirPollutionControlEquipment.pdf

[6] See Appendix B, pages 6 and 7. https://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/guidance_flashemission.pdf

pressure is experienced by a semi-volatile liquid, in which volatile species may evolve out of the liquid phase and into the gas phase. If these tanks are being filled at near-atmospheric conditions, then flashing should not be much of a problem for nafta but could be for alcohol. There is no proposed control for these atmospheric tanks.

9. The request for emission permit indicates that no glycol-based dehydration system would be used. Rather the platform will use a turboexpander refrigeration system to separate light ends, methane and ethane, from natural gas liquids (NGL) such as propane and butane. The system may use a compressor to increase the pressure of the inlet stream through a choke valve (or simply use the high pressure of the whole system) and then allowing the gas to expand through a turbine. The resulting expansion moves the turbine converting energy to mechanical work and cools the gas selectively condensing NGLs. The methane and ethane would not condense and the overhead gas is sent for further treatment. Typically, such a system is used in a natural gas treatment plant on a high calorific stream (rich in C3+) gas stream to separate NGL from natural gas. Although some water is incidentally removed, it is not a primary technology for dehydration. We also note that the gas compositions provided in the request for emission permit do not indicate that the gas would be particularly suitable for the turboexpander refrigeration system, as the gas is mainly composed of methane.

   In order for such a system to function properly, it is likely that the operator expects the gas to be dry (low water content) and dehydration is not required. This information should be confirmed by the Ministry of Environmental Protection upon startup of the project. If the gas is insufficiently dry for the use of a turboexpander refrigeration system as described, a dehydration system (either a glycol contact system or a molecular sieve) may be needed and emissions for such a system would need to be estimated. Note that a molecular sieve system is a closed system that does not generate continuous emissions.

10. The request for emission permit indicates that a number of large turbines will be used to provide power to the platform. We note that turbines for this purpose are meant to operate at a "sweet spot" of constant load. In the event that they are operated at a load substantially lower or higher than this normal load condition, substantially higher emissions of NOx can occur. The manufacturer test data will be very specific in mapping the NOx emissions as a function of load. It is difficult to know without seeing these specifications how high the NOx emissions can be.
11. Chapter 2 of the request for emission permit proposes to use TCEQ Method 28VHP – instrument LDAR monitoring. USEPA standards would reference 40 CFR Part 60, Subpart OOOOa which references Subpart VVa, "Standards of Performance for Equipment Leaks of VOC in SOCMI." Table 1 below provides a summary comparison of the requirements of TCEQ 28VHP and NSPS OOOOa (VVa).

Table 1. Summary comparison of LDAR requirements for TCEQ 28VHP and NSPS Subpart OOOOa (VVa).

Equipment	Service Type	Monitoring Frequency		Leak Definition (ppm)		Maintenance/Repair Requirements	
		NSPS OOOOa (VVa)	28VHP	NSPS OOOOa (VVa)	28VHP	NSPS VVa & OOOOa	28VHP
Compressors	GV	N/A	Quarterly[a]	N/A	2,000	Compressor are not an LDAR equipment type under NSPS OOOOa. They are regulated separately.	Under 28VHP, Periodic monitoring requirements do not apply to equipment where the VOC has an aggregate partial pressure of less than 0.044 psia at 68°F (i.e., definition of "HL components" under NSPS regulations). For pumps, compressors, valves, or connectors emitting VOC in excess of their respective leak threshold **OR** found by visual inspection (e.g., dripping process fluids): - First attempt at repair within 5 days; and - Repaired within 15 days For pumps and compressors, seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. For pressure relief valves equipped with a rupture disc upstream or venting to a control device, they are not required to be monitored
Pumps	LL	Monthly M21 & Weekly Visual	Quarterly[a]	2,000	2,000	- For M21 leak: 1st attempt at repair within 5 days and repair within 15 days - For visual inspection: monitor within 5 days to determine whether there is a leak **OR** designate the visual indications of liquid dripping as a leak.	
	HL	N/A	N/A	10,000	2,000	- For M21 leak: 1st attempt at repair within 5 days and repair within 15 days - For visual inspection: monitor within 5 days to determine whether there is a leak OR eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 days. - For HL equipment, no periodic monitoring required (see HL valves)	
Valves	GV	Monthly or Quarterly	Quarterly[b]	500	500	- Any valve for which a leak is not detected for 2 successive months may be monitored the first month of every quarter, beginning with the next quarter, until a leak is detected. - For M21 leak: 1st attempt at repair within 5 days and repair within 15 days - No requirements for visual indications of leaks	
	LL			500	500		

Equipment	**Service Type**	**Monitoring Frequency**		**Leak Definition (ppm)**		**Maintenance/Repair Requirements**	
		NSPS OOOOa (VVa)	**28VHP**	**NSPS OOOOa (VVa)**	**28VHP**	**NSPS VVa & OOOOa**	**28VHP**
	HL	N/A	N/A	10,000	500	- For M21 leak: 1st attempt at repair within 5 days and repair within 15 days - For visual inspection: monitor within 5 days to determine whether there is a leak OR eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 days.	
Pressure Relief Valves	GV	Quarterly and within 5 days of pressure release event	Quarterly[b]	500	500	- For M21 leak: 1st attempt at repair within 5 days and repair within 15 days - No requirements for visual indications of leaks	
	LL	N/A		10,000	500	- For M21 leak: 1st attempt at repair within 5 days and repair within 15 days - For visual inspection: monitor within 5 days to determine whether there is a leak OR eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 days.	
	HL	N/A	N/A	10,000	500		
Connectors (e.g., flanges)	GV	Within 12 months of the compliance date and every 1-8 years thereafter	Weekly Visual[c]	500	500	- For M21 leak: 1st attempt at repair within 5 days, repair within 15 days, and follow-up monitoring within 90 days of repair - No requirements for visual indications of leaks (except for inaccessible, ceramic, or ceramic-lined connectors)	
	LL			500	500		

Equipment	Service Type	Monitoring Frequency		Leak Definition (ppm)		Maintenance/Repair Requirements	
		NSPS OOOOa (VVa)	28VHP	NSPS OOOOa (VVa)	28VHP	NSPS VVa & OOOOa	28VHP
	HL	N/A		10,000	500	- For M21 leak: 1st attempt at repair within 5 days and repair within 15 days - For visual inspection: monitor within 5 days to determine whether there is a leak OR eliminate the visual, audible, olfactory, or other indication of a potential leak within 5 days.	
Open-Ended Lines	All	N/A	N/A - No periodic monitoring unless certain conditions are met[d]	N/A	500	Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or second valve at all times except during operations requiring process fluid flow through the open-ended valve or line. Each open-ended valve or line equipped with a second valve shall be operated in a manner such that the valve on the process fluid end is closed before the second valve is closed.	If a cap, blind flange, plug, or second valve is not installed within 72 hours of creating an open-ended line: - Repair the open-ended line within 24 hours; or - Install a cap, blind flange, plug, or second valve.

[a] *Valves that begin operation must also be monitored within 30 days after the end of its startup period to ensure proper installation.*
[a] *Pumps and compressors must be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal.*
[b] *Replacements for leaking valves shall be re-monitored within 15 days of being placed back into VOC service.*

[c] *Connectors must also have pressure testing* ***OR*** *gas analyzer monitoring performed within 15 days for new or reworked piping connections.*
[d] *If an open-ended line is created (e.g., during isolation of equipment for hot work or the removal of a component for repair which results in an open-ended line), the permittee must* ***either***:

Install a cap, blind flange, plug, or second valve on the line within 72 hours; or

Monitor once for leaks for a plant/unit turnaround lasting up to 45 days. For all other scenarios, monitor once within 72 hours of creating the open-ended line and monthly thereafter.

12. Chapter 3-6 of the request for emission permit indicates that two emergency diesel generators would be on site for backup power. However, no emissions are assigned to these generators. For safety purposes, emergency generators must typically be operated for a specific number of hours per month or year to ensure they function adequately. It is recommended that combustion emissions associated with minimal safety firing of the emergency generators be included in the emissions totals for the platform.
13. Forms provided in Chapter 3 were reviewed for the accuracy of specific quantitative information:
    a. Forms 3.1.2.2-1, 3.1.2.2-2, 3.1.2.2.-3 – the "name of material" entry for different sources is "Nitrogen oxides (NOx/ NO_2)" and "Sulphur oxides (SOx/SO_2)" with the same emission rate. Different agencies provide different guidance for the ratios of NOx to NO_2 and SOx to o2. SOx would be 100% SO_2; however, NOx from combustion can be a mixture of NO and NO_2, of which only NO_2 has an established air quality standard (in the U.S.). We would suggest that the request for emission permit include the ratios of NO to NO_2 for specific combustion units based on manufacturer's specifications. The request for emission permit should specify what the ratios need to be per source as it can significantly impact predicted short-term ambient concentrations of NO_2.
    b. Forms 3.1.2.2-2 and 3.1.2.2-3 and 3.5 – we note that HAPs, specifically formaldehyde (HCHO), benzene, toluene, ethylbenzene, xylene (BTEX) and n-hexane, have not been speciated. Particular to gas-fired engines, HCHO is considered a HAP and can constitute 50% of the total engine VOC emissions. BTEX and n-hexane tend to be present in larger concentrations in gas treatment systems. USEPA designates a source as "major" for HAPs if any single HAP (like HCHO) equals or exceeds 10 tons per year. Based on current emission estimates of NMVOC from engines in the request for emission permit, the proposed project would exceed USEPA major source standards if 30% or more of NMVOC is HCHO. Therefore it is critical that the HAP speciation be indicated.
    c. Form 3.3 C – fugitive emissions have been updated in the January 2019 revised request for emission permit, relative to the earlier version released in fall 2018. However, we note that gas lines are still not included for fugitive emissions based on the documents "Leviathan Valve Standards Letter" and "LPP-T-FDE-PRS-RPT-0020 1-7" included in Appendix 14.

2.2 Comments on Quantitative Emissions

Specific comments on various aspects of the request for emission permit are summarized below. These comments Table 2 below summarizes the total emissions of criteria pollutants as provided in Form 3.5 in the request for emission permit.

Table 2. Summary of Leviathan platform annual emissions.

Pollutant	Annual Emissions	Units
Nitrogen Oxides (NOx/NO_2)	422.56	metric ton/yr
Carbon monoxide (CO)	477.43	metric ton/yr
Dust or particulate matter (PM)	33.67	metric ton/yr
Sulfur oxides (SOx/SO_2)	36.47	metric ton/yr
NMVOC	26.83	metric ton/yr

Emissions of NOx and CO would lead the facility to be considered a "major source" under USEPA designation, and would be subject to New Source Review (NSR)[7] and Prevention of Significant Deterioration (PSD)[8]. If the platform were located in an attainment area in the U.S., the facility would have to undertake PSD review per 40 CFR 52.21. In addition, a project that is major for at least one criteria pollutant would be considered major for all criteria pollutants and would be subject to PSD review for those pollutants that exceed significant emission rates. In this case, the proposed Leviathan platform would trigger PSD review for all criteria pollutants. In this case, the project would require:

- Preconstruction monitoring of these pollutants;
- Implementation of Best Available Control Technology (BACT);
- Modeling demonstration that the project would not adversely impact National Ambient Air Quality Standards (NAAQS);
- Evaluation of Air Quality Related Values (AQRVs) such as pollutant deposition, and visibility impacts.

Finally, sources that are major for criteria pollutants would trigger PSD for greenhouse gases if the potential to emit exceeds 100,000 tons per year of carbon dioxide equivalent (CO_2e). This would require a Best Available Control Technology (BACT) evaluation for GHG emissions. Such an evaluation would include a thorough review of technology options for reducing emissions of GHGs, including aftertreatment systems, carbon capture systems, or other available technologies.

2.3 Review of Offshore Platform Emissions in the Gulf of Mexico

Ramboll conducted a review and summary of emissions from offshore platforms located in the Outer Continental Shelf (OCS) in the Gulf of Mexico. These platforms are permitted and monitored by the U.S. Bureau of Ocean Energy Management (BOEM). The emissions of the proposed Leviathan platform as disclosed in the request for emission permit were reviewed in the context of emissions from other offshore platforms in BOEM's GOADS database. Figure 1 shows the cumulative distribution of annual NOx emissions (tons per year) from individual platforms in the Gulf of Mexico, and Figure 2 shows the cumulative distribution of annual VOC emissions (tons per year) from these platforms.

[7] https://www.epa.gov/nsr

[8] https://www.epa.gov/nsr/prevention-significant-deterioration-basic-information

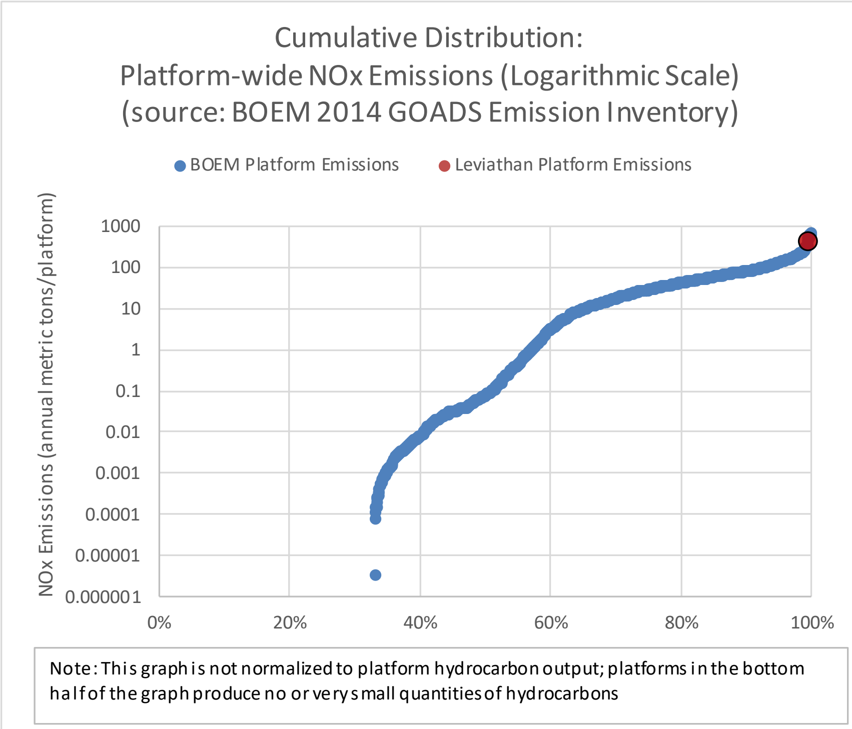

Figure 1. Cumulative distribution of annual NOx emissions for offshore platforms in the Gulf of Mexico.

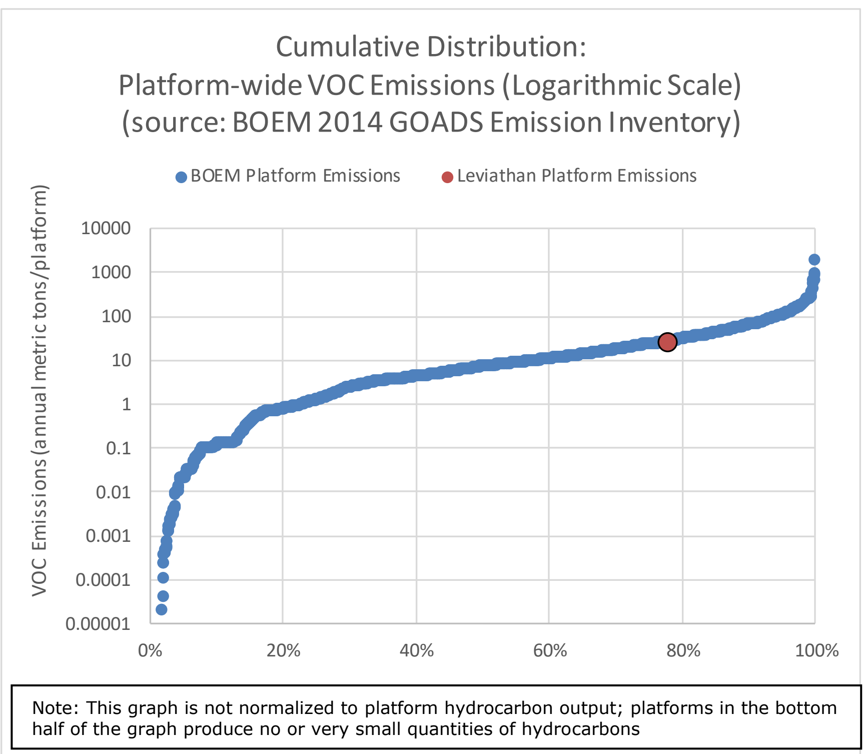

Figure 2. Cumulative distribution of annual VOC emissions for offshore platforms in the Gulf of Mexico.

Figure 1 suggests that the Leviathan platform would be near the very highest percentile for NOx emissions, similar to the less than 5% of the highest-emitting platforms in the Gulf of Mexico. By comparison, Figure 2 suggests that approximately 30% of platforms in the Gulf of Mexico would have higher VOC emissions than the Leviathan platform.

This suggests that NOx emissions from the Leviathan platform, as described in the request for emission permit, are similar to the largest, highest-emitting platforms in the U.S. Gulf of Mexico development area. Similarly, VOC emissions are comparable to the largest 30% of platforms in the Gulf of Mexico. Based on discussions with BOEM, the VOC emissions from the 70% of platforms below those of the Leviathan platform in the GOADS database are from platforms with very little gas production or that are otherwise out of operation or idled[9]. This suggests that for a high gas production platform such as the Leviathan platform, much larger VOC emissions would be expected than those described in the request for emission permit. Some of the comments made in section 2.1 above, if addressed properly in the request for emission permit, would lead to an increase in the VOC emission inventory for the proposed platform. We also note that the control system proposed here is novel and its operation has not been demonstrated for such a large scale operation. As noted above, close monitoring of this system is strongly recommended, particularly in the initial phase of operation of the platform, to ensure that the control efficiency as described in the request for emission permit is actually achieved.

[9] Personal communication – John Filostrat, BOEM Public Affairs, March 2019.

3.0 Reporting Requirements in the U.S.

At the request of Homeland Guards, Ramboll summarized the reporting requirements for offshore oil and gas platforms in the OCS in the Gulf of Mexico, subject to reporting to BOEM's GOADS system. GOADS is an electronic database which owners and operators of offshore oil and gas platforms in the OCS are required to use to report on activity and emissions from these platforms (including Noble Energy). BOEM has collected emission information related to offshore oil and gas operations to establish emission inventories for the Gulf of Mexico for calendar years 2000, 2005, 2008, 2011, 2014 and are currently collecting data for a 2017 emission inventory. GOADs is a calendar year survey program. Monthly surveys of air emissions-related activities that are associated with the platforms must be completed if new information is available. For example, if production or throughput volumes change from month to month, this new information is entered in each monthly survey. Parameters that remain constant do not need to be entered monthly. At the very least, GOADS tracks the following general data:

- General information about the company
- Structure information
  - Structure ID
  - BOEM complex ID
  - Geographic area name
  - Block number
  - Latitude/longitude of the structure
  - Lease number
  - Distance to shore
  - Water depth
  - Production data (volume of natural gas or oil products that were extracted at this structure during the specific survey period)
  - Throughput data (total volume of natural gas or oil products handled at the current structure during the survey period, including production volumes and volumes transferred by pipeline from another location)
  - Fuel usage
- Sales gas composition
- Source category data requirements

For source categories, an extensive list of data is required for each structure. Table 3 below summarizes the basic data for each source category (more detailed information is available through the GOADS system):

Table 3. List of data reporting requirements by equipment type in GOADS.

Equipment No.	Equipment Type	Equipment Information	
1.	Amine Gas Sweetening Unit	Processed throughput	Hours operated
		Unprocessed natural gas concentration (% by volume)	Amine type
		Equipped with a flash tank (y/n)	Disposition of flash gas
		Vented into low-presssure system	Gases vented or flared
2.	Boiler/heater/burner	Fuel type	Maximum rated heat input
		Hours operated	Average heat input
3.	Diesel or gasoline engine	Fuel type	Maximum rated horsepower
		Hours operated	Operating horsepower
		Maximum rated fuel usage	Average fuel usage
4.	Drilling equipment	Hours operated	Total diesel fuel usage
		Total gasoline usage	Total natural gas fuel usage
5.	Combustion flare	Volume flared reported for continuous and episodic flaring	Continous pilot
		Pilot fuel feed rate	
6.	Fugitives	Stream type (gas, heavy oil, light oil, or water/oil)	Average VOC weight %
		Number of components that handle the stream type	
7.	Glycol dehydrator unit	Processed throughput	Equipped with a flash tank (y/n)
		Disposition of flash gas	
8.	Loading operation	Volume loaded to ships and barges	Tank color
		Tank condition	
9.	Losses from flashing	Type of vessel	API gravity of stored oil
		Operating pressure of each vessel	Operating temperature of each vessel
		Operating pressure upstream of vessel	Operating temperature upstream of vessel
		Oil/condensate throughput for each vessel	Disposition of flash gas
10.	Natural gas engine	Engine stroke	Engine burn

Equipment No.	Equipment Type	Equipment Information	
		Hours operated	Maximum rated fuel usage
		Average fuel usage	
11.	Natural gas, diesel, or dual-fuel turbine	Hours operated	Operating horsepwoer
		Maximum rated fuel usage	Average fuel usage
12.	Mud degassing	Number of drilling days (with mud)	Mud type used (water-based, synthetic, oil-based)
13.	Pneumatic pumps	Manufacturer	Model
		Hour operated	
14.	Pneumatic controllers	Manufacturer	Model
		Bleed rate	Hours operated
		Service type	
15.	Storage tank	Product throughput	Product type
		Tank color	Tank condition
		Tank shape	Tank orientation
		Tank shell height	Tank shell diameter
		Tank shell width	Roof shape
		Roof height above shell	Equipped with a flash tank (y/n)
16.	Cold vent	Hours operated, including upsets	Volume vented, including upsets
		Control device identified	Average vent feed

As shown in Table 3, the reporting requirements in the GOADS system are extensive and include a number of categories (e.g. vessel loading at platforms, cold vents associated with upsets) that are not currently evaluated in the Leviathan request for emission permit.