TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

EXAMPLE A

AMENDED NOTICE OF APPLICATION AND PRELIMINARY DECISION FOR AN AIR QUALITY PERMIT

PROPOSED AIR QUALITY PERMIT NUMBERS: 158420, PSDTX1572, AND GHGPSDTX198

APPLICATION AND PRELIMINARY DECISION. Port Arthur LNG, LLC, 2925 Briarpark Drive Suite 900, Houston, TX 77042-3781, has applied to the Texas Commission on Environmental Quality (TCEQ) for issuance of Proposed Air Quality Permit 158420, Prevention of Significant Deterioration (PSD) Air Quality Permit PSDTX1572, and Greenhouse Gas Prevention of Significant Deterioration (GHGPSD) Air Quality Permit GHGPSDTX198, which would authorize construction of the Port Arthur LNG, located from the intersection of TX 82 and TX 87 in Port Arthur, travel south on TX 87 for 5.3 miles to oil field road, turn right and Port Arthur LNG is on the left, Port Arthur, Jefferson County, Texas 77642. This application was processed in an expedited manner, as allowed by the commission's rules in 30 Texas Administrative Code, Chapter 101, Subchapter J. This application was submitted to the TCEQ on September 12, 2019. The proposed facility will emit the following air contaminants in a significant amount: carbon monoxide, nitrogen oxides, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and particulate matter with diameters of 2.5 microns or less, sulfur dioxide, sulfuric acid mist, and greenhouse gases. In addition, the facility will emit the following air contaminants: ammonia.

The degree of PSD increment predicted to be consumed by the proposed facility and other increment-consuming sources in the area is as follows:

$PM_{2.5}$

Maximum Averaging Time	Maximum Increment Consumed (µg/m^3)	Allowable Increment (µg/m^3)
24-hour	8.8	9

The executive director has determined that the emissions of air contaminants from the proposed facility which are subject to PSD review will not violate any state or federal air quality regulations and will not have any significant adverse impact on soils, vegetation, or visibility. All air contaminants have been evaluated, and "best available control technology" will be used for the control of these contaminants.

The executive director has completed the technical review of the application and prepared a draft permit which, if approved, would establish the conditions under which the facility must operate. The permit application, executive director's preliminary decision, draft permit, and the executive director's preliminary determination summary and executive director's air quality analysis, will be available for viewing and copying at the TCEQ central office, the TCEQ Beaumont regional office, and at the Effie & Wilton Hebert Public Library, 2025 Merriman Street, Port Neches, Jefferson County, Texas, beginning the first day of publication of this notice. The facility's compliance file, if any exists, is available for public review at the TCEQ Beaumont Regional Office, 3870 Eastex Freeway, Beaumont, Texas.

INFORMATION AVAILABLE ONLINE. These documents are accessible through the Commission's Web site at www.tceq.texas.gov/goto/cid: the executive director's preliminary decision which includes the draft permit, the executive director's preliminary determination summary, the air quality analysis, and, once available, the executive director's response to comments and the final decision on this application. Access the Commissioners' Integrated Database (CID) using the above link and enter the permit number for this application. The public location mentioned above, *Effie & Wilton Hebert Public Library*, provides public access to the internet. This link to an electronic map of the site or facility's general location is provided as a public courtesy and not part of the application or notice. For exact location, refer to application. http://www.tceq.texas.gov/assets/public/hb610/index.html?lat=29.785277&lng=-93.948888&zoom=13&type=r.

PUBLIC COMMENT/PUBLIC MEETING. You may submit public comments or request a public meeting about this application. The purpose of a public meeting is to provide the opportunity to submit comment or to ask questions about the application. The TCEQ will hold a public meeting if the executive director determines that there is a significant degree of public interest in the application, if requested by an interested person, or if requested by a local legislator. A public meeting is not a contested case hearing. **You may submit additional written public comments within 30 days of the date of newspaper publication of this notice in the manner set forth in the AGENCY CONTACTS AND INFORMATION paragraph below.**

After the deadline for public comment, the executive director will consider the comments and prepare a response to all public comment. **The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application.**

OPPORTUNITY FOR A CONTESTED CASE HEARING. A contested case hearing is a legal proceeding similar to a civil trial in a state district court. **A person who may be affected by emissions of air contaminants from the facility is entitled to request a hearing. A contested case hearing request must include the following: (1) your name (or for a group or association, an official representative), mailing address, daytime phone number; (2) applicant's name and permit number; (3) the statement "I/we request a contested case hearing;" (4) a specific description of how you would be adversely affected by the application and air emissions from the facility in a way not common to the general public; (5) the location and distance of your property relative to the facility; (6) a description of how you use the property which may be impacted by the facility; and (7) a list of all disputed issues of fact that you submit during the comment period. If the request is made by a group or association, one or more members who have standing to request a hearing must be identified by name and physical address. The interests the group or association seeks to protect must also be identified. You may also submit your proposed adjustments to the application/permit which would satisfy your concerns. Requests for a contested case hearing must be submitted in writing within 30 days following this notice to the Office of the Chief Clerk, at the address provided in the information section below.**

A contested case hearing will only be granted based on disputed issues of fact or mixed questions of fact and law that are relevant and material to the Commission's decisions on the application. The Commission may only grant a request for a contested case hearing on issues the requestor submitted in their timely comments that were not subsequently withdrawn. Issues that are not submitted in public comments may not be considered during a hearing.

EXECUTIVE DIRECTOR ACTION. If a timely contested case hearing request is not received or if all timely contested case hearing requests are withdrawn, the executive director may issue final approval of the application. The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application, and will be posted electronically to the CID. If any timely hearing requests are received and not withdrawn, the executive director will not issue final approval of the permit and will forward the application and requests to the Commissioners for their consideration at a scheduled commission meeting.

MAILING LIST. You may ask to be placed on a mailing list to obtain additional information on this application by sending a request to the Office of the Chief Clerk at the address below.

AGENCY CONTACTS AND INFORMATION. Public comments and requests must be submitted either electronically at www14.tceq.texas.gov/epic/eComment/, or in writing to the Texas Commission on Environmental Quality, Office of the Chief Clerk, MC-105, P.O. Box 13087, Austin, Texas 78711-3087. Please be aware that any contact information you provide, including your name, phone number, email address and physical address will become part of the agency's public record. For more information about this permit application or the permitting process, please call the Public Education Program toll free at 1-800-687-4040. Si desea información en Español, puede llamar al 1-800-687-4040.

Further information may also be obtained from Port Arthur LNG, LLC at the address stated above or by calling Mr. Kerry Higgins, Senior Director Technical Services at (281) 446-7070.

Amended Notice Issuance Date: June 5, 2020

Special Conditions

Permit Numbers 158420, PSDTX1572, and GHGPSDTX198

1. This permit authorizes emissions only from those emission points listed in the attached table entitled “Emission Sources - Maximum Allowable Emission Rates,” (MAERT) and the facilities covered by this permit are authorized to emit subject to the emission rate limits on that table and other operating conditions specified in this permit. Also, this permit authorizes the emissions from planned maintenance, startup, and shutdown (MSS).

   If any condition of this permit is more stringent than the regulations so incorporated, then for the purposes of complying with this permit, the permit shall govern and be the standard by which compliance shall be demonstrated.

Federal Applicability

2. These facilities shall comply with applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on Standards of Performance for New Stationary Sources (NSPS), Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):

   A. Subpart A: General Provisions.

   B. Subpart Kb: The liquid condensate storage tanks will be subject to Standards of Performance for Volatile Organic Liquids Storage Vessels.

   C. Subpart VV: The condensate storage system will be subject to Standards of Performance for Equipment Leaks of Volatile Organic Compounds (VOC).

   D. Subpart NNN: The demethanizer and debutanizer column vents will be subject to Standards of Performance for Volatile Organic Compounds - Distillation Operations.

   E. Subpart KKKK: The combustion turbines will be subject to Standards of Performance for Stationary Combustion Turbines.

   F. Subpart IIII: The diesel-fired standby generators and fire water pump engines will be subject to Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

   G. Subpart XX: Condensate loading will be subject to Standards of Performance for Bulk Gasoline Terminals.

3. These facilities shall comply with applicable requirements of the EPA regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories, 40 CFR Part 63:

   A. Subpart A: General Provisions.

   B. Subpart ZZZZ: The diesel-fired standby generators and fire water pump engines will be subject to National Emission Standard for Hazardous Air Pollutants for

Stationary Reciprocating Internal Combustion Engines. According to 40 CFR § 63.6590(c)(1), compliance with Part 63 is met by compliance with NSPS Subpart IIII.

C. Subpart EEEE: The liquid condensate tanks and condensate truck loading will be subject to National Emission Standard for Hazardous Air Pollutants for Organic Liquid Distribution (Non-Gasoline).

D. Subpart YYYY: The stationary combustion turbines will be subject to National Emission Standard for Hazardous Air Pollutants for Stationary Combustion Turbines.

Emissions Standards and Operating Specifications

4. Each diesel-fired standby generator shall not exceed 24 hours of non-emergency operation per year, on a rolling 12-month basis. Each fire water pump engine shall not exceed 39 hours of non-emergency operation per year, on a rolling 12-month basis. Each engine must be equipped with a non-resettable runtime meter.

5. The diesel fuel fired in the standby generator and fire water pump engines authorized in this permit shall contain no more than 15 parts per million (ppm) of sulfur by weight. Fuel gas (as identified in the permit application), boil-off gas and pipeline quality natural gas burned as fuel in the combustion turbines and fuel preheaters shall contain no more than three grains total sulfur per 100 dry standard cubic feet (dscf) on an hourly average basis and half a grain total sulfur per 100 dscf on an annual average basis.

   Upon request by the Executive Director of the Texas Commission on Environmental Quality (TCEQ) or any local air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel or shall allow air pollution control agency representatives to obtain a sample for analysis.

6. The marine flare (emission point number [EPN] M-FLARE) and the ground flare (EPN G-FLARE) shall be designed and operated in accordance with the following requirements:

   A. The flare system shall be designed such that the combined gas and waste stream to each flare meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity under normal and, anticipated scenarios identified in the air permit application.

   B. Fuel for the flare pilots is limited to fuel gas (as identified in the permit application), boil-off gas, pipeline quality natural gas, or a blend of these fuels.

   C. The flare shall be operated with a flame present at all times and/or have a constant pilot flame. The pilot flame shall be continuously monitored by a thermocouple, flame-ionization rod, acoustical monitor, infrared monitor, or other equivalent technology. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to within manufacturer's specifications, and shall be calibrated at a frequency in accordance with the manufacturer's specifications.

D. The flare shall be operated with no visible emissions except during periods not to exceed a total of five minutes during any two consecutive hours.

E. The permit holder shall install a continuous, pressure and temperature compensated, flow monitor that provides a record of the vent stream flow to the flare in units of standard cubic feet. The flow monitor shall be installed in the vent stream such that the total vent stream to flare is measured. Flow measurements shall be taken continuously, and values shall be recorded on an average one hour basis.

The flow monitor shall be calibrated according to manufacturer's instructions, or shall have a calibration check by using a second calibrated flow measurement device, annually to meet the following accuracy specifications: the flow monitor shall be +/- 5.0% of the design flow, temperature sensor shall be +/- 2.0% at absolute temperature, and pressure sensor shall be +/- 5.0 mmHg.

The flow monitor shall operate at least 95% of the time when the flare is operational, averaged over a rolling twelve (12) month period.

F. Vent gas (including pilot gas) sent to the marine flare shall not exceed 384 million standard cubic feet per year (MMscf/year), based on a rolling 12-month total. Vent gas (including pilot gas) sent to the ground flare shall not exceed 753 MMscf/year, based on a rolling 12-month total. Additionally, planned MSS vent gas (including pilot gas) sent to the ground flare shall not exceed 5245 MMscf/year, based on a rolling 12-month total. These limits do not include vent gas sent to the flare systems from emergency or upset conditions.

7. The combustion turbines (EPN CT-COMP-1, CT-COMP-2, CT-COMP-3, CT-COMP-4, CT-COMP-5, CT-COMP-6, CT-COMP-7, CT-COMP-8, CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, and CT-GEN-9) shall adhere to the following emissions standards and operating specifications.

A. Fuel fired in the refrigeration compression combustion turbines is limited to fuel gas (as identified in the permit application), boil-off gas, pipeline quality natural gas, or a blend of these fuels. Fuel fired in the electric power generation combustion turbines is limited to pipeline quality natural gas.

B. The concentration of pollutants in the exhaust gas from the turbines shall not exceed the performance standards listed in the tables below. These performance standards shall apply at all times except during periods of planned MSS. Pollutant concentrations listed in the tables below are in units of ppmvd corrected to 15 percent oxygen (O2).

Table 1. Refrigeration Compressor Combustion Turbine Performance Standards (EPNs CT-COMP-1 through CT-COMP-8)

Pollutant	Performance Standard (ppmvd)	Compliance Averaging Period
NO_x	9.0	24-hour rolling
CO	25.0	3-hour rolling
VOC	2.0	3-hour rolling

Table 2. Electric Power Generation Combustion Turbine Performance Standards (EPNs CT-GEN-1 thru CT-GEN-9)

Pollutant	Performance Standard (ppmvd)	Compliance Averaging Period
NO_x	5.0	24-hour rolling
CO	9.0	3-hour rolling
VOC	2.0	3-hour rolling
NH_3	10.0	3-hour rolling

C. Planned startup or shutdown events are limited to 60 minutes per event for each individual combustion turbine.

D. Authorized maintenance activities include the initial commissioning of the turbines and other major dry low nitrogen oxide (NO_x) burner tuning sessions. Major tuning sessions are scheduled events, and would occur after the completion of initial construction, a combustor change-out, a major repair, maintenance to a combustor, or other similar circumstances.

E. Only eight out of the nine electric power generation combustion turbines (EPNs CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, or CT-GEN-9) may operate at the same time (i.e. during the same one-hour block interval).

F. Annual net-electric sales to the electric grid from each electric power generation combustion turbines (EPNs CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, or CT-GEN-9) shall not exceed 219,000 megawatt-hours (MWh).

G. Emissions shall not exceed the maximum allowable emission rates specified in the MAERT under all operating scenarios, including periods of authorized MSS activities.

8. Fuel for the thermal oxidizers (EPNs TO-1, TO-2, TO-3, and TO-4) is limited to fuel gas (as identified in the permit application), boil-off gas, pipeline quality natural gas, or a blend of these fuels. Vent gases from the acid gas removal unit shall be routed to each train's dedicated thermal oxidizer.

9. Opacity of emissions from each combustion turbine and each thermal oxidizer shall not exceed five percent averaged over a six-minute period from each stack. Observations shall be performed and recorded quarterly. This determination shall be made by first observing for visible emissions while each facility is in normal operation. Observations shall be made at least 15 feet and no more than 0.25 miles from the emission point(s). Up to three emissions points may be read concurrently, provided that all three emissions points are within a 70-degree viewing sector or angle in front of the observer such that the proper sun position (at the observer's back) can be maintained for all three emission points. If visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using 40 CFR Part 60, Appendix A, Test Method 9. If the opacity exceeds five percent, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation.

10. The inlet gas conditioning will include a mercury removal unit, acid gas removal unit, dehydration unit, and acid gas thermal treatment comprised of four thermal oxidizers (EPNs TO-1, TO-2, TO-3, and TO-4). Acid gases from the amine regenerator reflux drum and flash gas from the rich amine flash drum shall be routed to each train's dedicated thermal oxidizer.

11. Tanks and condensate loading shall be operated and maintained according to the following:

A. Diesel tanks dedicated to fire water pumps (EPNs TK-DSLF-1 and TK-DSLF-2) shall be painted red. All other diesel tanks, amine tanks, hot oil and slop oil storage tanks shall be painted white or aluminum. All tanks shall utilize a submerged fill pipe.

(1) The permit holder shall maintain an emissions record which includes calculated emissions of VOC from all storage tanks during the previous calendar month and the past consecutive 12-month period. The record shall include tank identification number, control method used, tank capacity in gallons, name of the material stored, VOC molecular weight, VOC monthly average temperature in degrees Fahrenheit, VOC vapor pressure at the monthly average material temperature in psia, VOC throughput for the previous month and year-to-date. Records of VOC monthly average temperature are not required to be kept for unheated tanks which receive liquids that are at or below ambient temperatures.

(2) Emissions from tanks shall be calculated using the methods that were used to determine the MAERT limits in the permit application Form PI-1 dated September 12, 2019. Sample calculations from the application shall be attached to a copy of this permit at the plant site.

B. The condensate storage tanks, and condensate truck loading operations shall be routed to the ground flare.

(1) The permit holder shall maintain and update a monthly emissions record which includes calculated emissions of VOC from all loading operations over the previous rolling 12-month period. The record shall include the loading spot, control method used, quantity loaded in gallons, name of the liquid loaded, vapor molecular weight, liquid temperature in degrees Fahrenheit, liquid vapor pressure at the liquid temperature in psia, liquid throughput for the previous month and rolling 12 months to date. Records of VOC temperature are not required to be kept for liquids loaded from unheated tanks which receive liquids at or below ambient temperatures. Emissions shall be calculated using the equations provided in the PI-1 dated September 12, 2019, and subsequent updates.

(2) All lines and connectors shall be visually inspected for any defects prior to hookup. Lines and connectors that are visibly damaged shall be removed from service. Operations shall cease immediately upon detection of any liquid leaking from the lines or connections.

(3) Each tank truck shall be leak checked and certified annually in accordance with Title 40 Code of Federal Regulations Part 60 (40 CFR 60), Subpart XX. The permit holder shall not allow a tank truck to be filled unless it has passed a leak-tight test within the past year as evidenced by a certificate which shows the date the tank truck last passed the leak-tight

test required by this condition and the identification number of the tank truck.

12. Fuel fired in the two preheaters shall be limited to fuel gas (as identified in the permit application), boil-off gas, pipeline quality natural gas, or a blend of these fuels. Heat input to each of the two fuel preheaters shall not exceed 3.8 million British thermal units per hour.

Ammonia (NH_3) Handling

13. The permit holder shall maintain prevention and protection measures for the NH_3 storage system. The NH_3 storage tank area will be marked and protected so as to protect the NH_3 storage area from accidents that could cause a rupture. The aqueous ammonia stored shall have a concentration of less than 20% NH_3 by weight.

14. In addition to the requirements of Special Condition No. 13, the permit holder shall maintain the piping and valves in NH_3 service as follows:

    A. Audio, visual, and olfactory (AVO) checks for NH_3 leaks shall be made once per day.

    B. Immediately, but no later than 24 hours following detection of a leak, plant personnel shall take one or more of the following actions:

        (1) Locate and isolate the leak, if necessary.

        (2) Commence repair or replacement of the leaking component.

        (3) Use a leak collection or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

Piping, Valves, Connectors, Pumps, Agitators, and Compressors - 28VHP

15. Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

    A. The requirements of paragraphs F and G shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 pounds per square inch, absolute (psia) at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

       The exempted components may be identified by one or more of the following methods:

(1) piping and instrumentation diagram (PID);

(2) a written or electronic database or electronic file;

(3) color coding;

(4) a form of weatherproof identification; or

(5) designation of exempted process unit boundaries.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked buried connectors shall be welded.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made readily available upon request. The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in subparagraph A above. If an unsafe-to-monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times. A difficult-to-monitor component for which quarterly monitoring is specified may instead be monitored annually.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open-ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

(1) a cap, blind flange, plug, or second valve must be installed on the line or valve; or

(2) the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once within the 72-hour period following the creation of the open-ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings of 500 ppmv and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. If a relief valve is equipped with rupture disc, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity.

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed at least quarterly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.
The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR Part 60, Appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. A calculated average is not required when all of the compounds in the mixture have a response factor less than 10 using methane. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

I. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I), the TCEQ Regional Manager and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. The instrument monitoring record shall include the time that monitoring took place for no less than 95% of the instrument readings recorded. Records of physical inspections shall be noted in the operator's log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC § 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable NSPS, or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS) and does not constitute approval of alternative standards for these regulations.

Initial Determination of Compliance

16. Sampling ports and platforms shall be incorporated into the design of the combustion turbine and thermal oxidizer exhaust stacks according to the specifications set forth in the attachment entitled "TCEQ Sampling Procedures Manual, Chapter 2, Stack Sampling Facilities." Alternate sampling facility designs may be submitted for approval by the TCEQ Regional Director.

17. The holder of this permit shall perform stack sampling and other testing as required to establish the actual quantities of air contaminants being emitted into the atmosphere from EPNs CT-COMP-1, CT-COMP-2, CT-COMP-3, CT-COMP-4, CT-COMP-5, CT-COMP-6, CT-COMP-7, CT-COMP-8, CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, CT-GEN-9, TO-1, TO-2, TO-3, and TO-4, to determine initial compliance with emission limits established in this permit. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods to be determined during the pretest meeting.

Fuel sampling using the methods and procedures of 40 CFR § 60.4415 may be conducted in lieu of stack sampling for sulfur dioxide (SO_2) or the permit holder may be exempted from fuel monitoring of SO_2 as provided under 40 CFR § 60.4365(a). If fuel sampling is used, compliance with NSPS Subpart KKKK, SO_2 limits shall be based on 100 percent conversion of the sulfur in the fuel to SO_2. Any deviations from those procedures must be approved by the Executive Director of the TCEQ prior to sampling. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.

A. The TCEQ Beaumont Regional Office shall be contacted as soon as testing is scheduled but not less than 45 days prior to sampling to schedule a pretest meeting.

The notice shall include:

(1) Date for pretest meeting.

(2) Date sampling will occur.

(3) Name of firm conducting sampling.

(4) Type of sampling equipment to be used.

(5) Method or procedure to be used in sampling.

(6) Procedure used to determine turbine loads during and after the sampling period.

The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports. A written proposed description of any deviation from sampling procedures specified in permit conditions, or the TCEQ or EPA sampling procedures shall be made available to the TCEQ prior to the pretest meeting. The TCEQ Regional Director shall approve or disapprove of any deviation from specified sampling procedures. Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office of Air, Air Permits Division. Test waivers and alternate or equivalent procedure proposals for NSPS testing which must have EPA approval shall be submitted to the EPA and copied to TCEQ Regional Director.

B. Air contaminants and diluents to be sampled and analyzed include (but are not limited to)

(1) For EPNs EPN CT-COMP-1, CT-COMP-2, CT-COMP-3, CT-COMP-4, CT-COMP-5, CT-COMP-6, CT-COMP-7, CT-COMP-8, CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, and CT-GEN-9: NO_x, carbon monoxide (CO), VOC, SO_2, NH_3 (generator turbines only), and O_2. Fuel sampling using the methods and procedures of 40 CFR § 60.4415 or 40 CFR § 60.4365(a) may be conducted for monitoring SO_2.

(2) For EPNs TO-1, TO-2, TO-3, and TO-4: NO_x, CO, VOC, SO_2, total particulate matter (PM), and O_2.

C. For each EPN TO-1, TO-2, TO-3, and TO-4, a VOC destruction efficiency of at least 99.9% or a VOC outlet concentration of 2 ppmvd or less corrected to 3 percent oxygen must be demonstrated, based upon the average of three one-hour sampling test runs. The minimum operating temperature shall be the average temperature at which compliance with the above was demonstrated.

D. Testing Conditions.

(1) EPNs CT-COMP-1, CT-COMP-2, CT-COMP-3, CT-COMP-4, CT-COMP-5, CT-COMP-6, CT-COMP-7, CT-COMP-8, CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, and CT-GEN-9, shall each be tested at or above 90% of the maximum turbine load for the given atmospheric conditions at the time of testing. Each tested turbine load shall be identified in the sampling report.

(2) EPNs TO-1, TO-2, TO-3, and TO-4, shall each be tested at least 90% of the associated acid gas removal unit design gas feed rate.

E. Sampling as required by this condition shall occur within 60 days after achieving commencement of commercial operation of each respective liquefied natural gas (LNG) train, but no later than 180 days after commencement of commercial operation of each LNG train. Additional sampling may be required by TCEQ or EPA.

F. Within 60 days after the completion of the testing and sampling required herein, two copies of the sampling reports shall be distributed as follows:

(1) One copy to the TCEQ Beaumont Regional Office.

(2) One copy to the EPA Region 6 Office, Dallas.

Continuous Demonstration of Compliance

18. The holder of this permit shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) to measure and record the concentrations of NOx, CO, and diluents (O2 or carbon dioxide (CO2)) in the turbine exhaust (EPNs CT-COMP-1, CT-COMP-2, CT-COMP-3, CT-COMP-4, CT-COMP-5, CT-COMP-6, CT-COMP-7, CT-COMP-8, CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, and CT-GEN-9). As an alternative to installing and operating a CEMS, the permit holder may install, calibrate, and maintain a predictive emission monitoring system (PEMS) to measure and record the in-stack concentration of any pollutant required to be monitored by a CEMS from the gas turbines identified above.

A. The CEMS or PEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and data analysis and reporting requirements specified in the applicable Performance Specifications in 40 CFR Part 60, Appendix B. The CEMS shall follow the monitoring requirements of 40 CFR § 60.13. The PEMS shall also follow the requirements of 30 TAC § 117.8100(b).

B. The NOx/diluent CEMS or PEMS must be operated according to the methods and procedures as set out in 40 CFR § 60.4345.

C. The CO CEMS or PEMS shall meet the appropriate quality assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur at least two months apart.

D. The TCEQ Beaumont Regional Office shall be notified at least 21 days prior to any required relative accuracy test audit in order to provide them the opportunity to observe the testing.

E. Monitored NO_x and CO concentrations must be corrected and recorded in dimensional units and averaging times corresponding to the emission limitations in

Special Condition No. 7 and the MAERT. Compliance for monitored pollutants is based on this data.

F. The CEMS or PEMS shall be operational during 95 percent of the operating hours of the facility, exclusive of the time required for zero and span checks. If this operational criterion is not met for the reporting quarter, the holder of this permit shall develop and implement a monitor quality improvement plan. The monitor quality improvement plan shall be developed and submitted to the TCEQ Beaumont Regional Office for their approval within six months. The plan should address the downtime issues to improve availability and reliability.

A CEMS or PEMS with downtime due to breakdown, malfunction, or repair of more than 10% of the facility operating time for any calendar year shall be considered as a defective CEMS or PEMS and the applicable CEMS or PEMS component(s) shall be replaced within 30 days.

19. The NH_3 concentration in the stack of the generator turbine exhaust (EPNs CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, and CT-GEN-9) shall be tested or calculated according to one of the methods listed below and shall be monitored according to one of the methods listed below. Monitoring NH_3 slip is only required on days when the selective catalytic reduction (SCR) unit is in operation.

A. The permit holder may install and operate a second NO_x CEMS probe located before the SCR, upstream of the stack NO_x CEMS, which may be used in association with the SCR efficiency and NH_3 injection rate to estimate NH_3 slip. This condition shall not be construed to set a minimum NO_x reduction efficiency on the SCR unit.

B. The permit holder may install and operate a dual stream system of NO_x CEMS at the exit of the SCR. One of the exhaust streams would be routed, in an unconverted state, to one NO_x CEMS and the other exhaust stream would be routed through a NH_3 converter to convert NH_3 to NO_x and then to a second NO_x CEMS. The NH_3 slip concentration shall be calculated from the delta between the two NO_x CEMS readings (converted and unconverted).

C. Any other method used for measuring NH_3 slip shall require prior approval from the TCEQ Office of Air, Air Permits Division.

Thermal Oxidizers

20. Vent gas from the Acid Gas Removal Unit and other gas streams represented in the air permit application must be directed to any of the four TOs. The TO combustion chamber outlet temperatures and exhaust oxygen concentration for EPNs TO-1, TO-2, TO-3, and TO-4, shall be continuously monitored when vent gases are directed to any of the four TOs. The outlet temperature and oxygen concentration must be recorded at least four times an hour (once per quarter of the hour) and averaged hourly for compliance demonstration when vent gases are directed to any of the four TOs. A partial

operational hour with greater than 30 minutes of data and two recorded outlet temperature and oxygen concentrations measurements shall count as a valid hour.

A. The minimum outlet temperature shall be 1400 degrees Fahrenheit until a minimum operating temperature is established by the testing required in Special Condition No. 17. The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have accuracy the greater of 1 percent of the temperature being measured or 4.5 degrees Fahrenheit.

B. Each TO shall be equipped with low NO_x burners and emit less than 0.06 lb NO_x/MMBtu.

C. The minimum exhaust oxygen concentration shall not be less than 3 percent oxygen. The oxygen monitor shall be zeroed and spanned daily and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in Performance Specification No. 3, 40 CFR Part 60, Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days. The oxygen monitor shall be audited in accordance with §5.1 of 40 CFR Part 60, Appendix F with the following exception to Procedure 1, § 5.1.2: the monitor may be quality-assured semiannually using cylinder gas audits (CGAs) and a relative accuracy test audit is not required once every four quarters (i.e., two successive semiannual CGAs may be conducted). An equivalent quality assurance method approved by the TCEQ may also be used. Successive semiannual audits shall occur no closer than four months. Necessary corrective action shall be taken for all CGA exceedances of ±15 percent accuracy and any continuous emissions monitoring system downtime in excess of 5 percent of the time when waste gas is directed to the TO. These occurrences and corrective actions shall be reported to the appropriate TCEQ Regional Director on a quarterly basis. No report is required if no corrective action was necessary. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Director.

Quality assured (or valid) data must be generated when waste gas is directed to the TO except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in minutes) that the TO operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

21. The permit holder shall determine SO_2 emissions from each of the four TOs by utilizing a mass balance of sulfur upstream and downstream of the TOs. The permit holder shall analyze gas sulfur content, at least quarterly, by sampling the gas prior to the first acid gas treatment device and by sampling the gas sulfur content after the last acid gas treatment device prior to being loaded onto a ship. The permit holder may use ASTM methods D1072, D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 to determine sulfur content in the gas streams. Additionally,

the permit holder shall monitor total feed gas flow into and out of the Acid Gas Removal Unit on an hourly basis. The flow monitor must receive an in situ third-party certification on an annual basis to demonstrate it will meet ± 5.0% accuracy.

Maintenance, Startup, and Shutdown

22. Sections of the plant undergoing shutdown or maintenance that requires breaking a line or opening a vessel shall be depressurized, emptied, degassed, and placed in service in accordance with the following requirements. The process equipment shall be degassed using good engineering and best management practices to ensure air contaminants are removed from the system through a control device, to the extent allowed by process equipment or storage vessel design. The facilities to be degassed shall not be vented directly to atmosphere, except as necessary to establish isolation of the work area or to monitor VOC concentration following controlled depressurization. The venting shall be minimized to the maximum extent practicable and actions taken recorded. The control device or recovery system utilized shall be recorded with the estimated emissions from controlled and uncontrolled degassing calculated using the methods that were used to determine allowable emissions for the permit application.

23. All contents from process equipment or storage tanks must be removed to the maximum extent practicable prior to opening equipment to commence degassing and maintenance. Liquid and solid removal must be directed to covered containment, recycled, or disposed of properly. If it is necessary to drain liquid into an open pan or the sump, the liquid must be covered and transferred to a covered vessel within one hour of being drained.

Alternative Means of Compliance (AMOC)

24. If a request for an AMOC is granted by the regulating authority (TCEQ or EPA) for the ground flare (EPN G-FLARE), the requirement of the approved AMOC shall supersede the requirements of Special Conditions No. 6. The permit holder shall incorporate these conditions into the permit through an alteration no later than 90 days after approval of the AMOC.

Recordkeeping Requirements

25. The following records must be kept at the plant for the life of the permit. All records required in this permit must be made available at the request of personnel from the TCEQ, EPA, or any air pollution control agency with jurisdiction:

    A. A copy of this permit.

    B. Permit application dated September 2019, the February 2020 updates to the original applications, and subsequent permit application representations submitted to the TCEQ.

C. A complete copy of the testing reports and records of the initial performance testing completed pursuant to Special Condition No. 17 to demonstrate initial compliance.

26. The following information must be maintained by the holder of this permit in a form suitable for inspection for a period of five years after collection and must be made available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:

A. Records of the sulfur content of the diesel fuel fired in the standby generator and fire water pump engines to show compliance with Special Conditions No.5. Fuel delivery receipts are an acceptable record.

B. Records of standby generator and fire water pump engine hours of operation to show compliance with Special Condition No. 4 including date, time, and duration of operation.

C. Records of pilot flame loss required by Special Condition No. 6C.

D. Records of hourly flow rates to the flare as required by Special Condition No. 6E and totals on a monthly and rolling 12-month basis.

E. The CEMS data of NO_x, CO, and O_2 emissions from EPNs CT-COMP-1, CT-COMP-2, CT-COMP-3, CT-COMP-4, CT-COMP-5, CT-COMP-6, CT-COMP-7, CT-COMP-8, CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, and CT-GEN-9, to demonstrate compliance with concentration limits in Special Condition No. 7 and with the emission rates listed in the MAERT.

F. Raw data files of all CEMS data including calibration checks, adjustments, and maintenance performed on these systems in a permanent form suitable for inspection.

G. Records of visible emissions and opacity observations and any corrective actions taken pursuant to Special Condition No. 9.

H. Records of ammonia concentration, AVO checks, and maintenance performed to any piping and valves in NH_3 service, and records of accidental releases, spills, or venting of NH_3 and the corrective action taken pursuant to Special Condition Nos. 13 and 14.

I. Records of NH_3 monitoring pursuant to Special Condition No. 19.

J. Records of TO exhaust temperature and oxygen concentration as required by Special Condition No. 20 on an hourly basis.

K. Records of calculated SO_2 emissions from the thermal oxidizers, including records of gas sulfur content sampling and gas flow rates pursuant to Special Condition No. 21.

L. Records required by Special Condition No. 15 related to the leak detection and repair program.

M. Records of miscellaneous maintenance, startup and shutdown activities at the plant, including:

(1) Date, time, and duration of the event; and

(2) Emissions from the event.

Additional GHG Specific Conditions

27. Combustion turbines used for refrigeration compression (EPN CT-COMP-1, CT-COMP-2, CT-COMP-3, CT-COMP-4, CT-COMP-5, CT-COMP-6, CT-COMP-7, and CT-COMP-8) shall adhere to the following emissions standards and operating specifications.

A. The applicant represented the following design choices that will improve efficiency and decrease GHG emissions: selection of efficient “E” class gas turbines, utilization of a heat recovery on the four (4) Propane Compressor Combustion Turbines only to heat oil circulated in the Hot Oil Circulation Pumps, and minimization of heat losses with insulation applied to the turbine casings.

B. Emission of CO_2 from each combustion turbine during MSS operation must not exceed 115,068 pounds/hour, on a block one-hour average and shall also be minimized by adhering to startup and shutdown duration limits identified in Special Condition No. 7.

C. Emissions of CO_2e shall not exceed the maximum allowable emission rates specified in the MAERT under all operating scenarios, including periods of authorized MSS activities.

28. Each electric power generation combustion turbines (EPN CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, and CT-GEN-9) shall adhere to the following emissions standards and operating specifications, on a 12-month rolling average during non-MSS operation.

A. Emissions of CO_2 from each turbine must not exceed 1,053 pounds per megawatt-hour (lbs/MWh) based on generator gross output.

B. Emission of CO_2 from each combustion turbine during MSS operation must not exceed 35,788 pounds/hour, on a block one-hour average and shall also be minimized by adhering to startup and shutdown duration limits identified in Special Condition No. 7.

C. Emissions shall not exceed the maximum allowable emission rates of CO_2e specified in the MAERT under all operating scenarios, including periods of authorized MSS activities.

29. The permit holder shall continuously monitor and record the average hourly fuel consumption of the combustion turbines with individual flow measurements being taken no less frequently than once every 15 minutes. The fuel flow meters shall be installed,

calibrated, maintained, and operated according to the manufacturer's instructions. Fuel flow meters shall be recalibrated annually. The flow meters shall be accurate to ± 5.0 percent of the unit’s maximum flow. Alternatively, fuel flow meters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 are acceptable. Fuel flow meter data shall be automatically recorded with a data acquisition and handling system. Additionally, the permit holder shall monitor and record the gross electric output produced by the combustion turbine electric generators. The monitoring system data shall be used to demonstrate continuous compliance with the performance specifications of Special Condition Nos. 27 and 28 and the emission limits of CO_2e in the attached MAERT.

30. The permit holder shall continuously monitor and record (1) the average hourly flow rate to each thermal oxidizer from the vent of each Acid Gas Removal Unit and (2) the average hourly fuel consumption of each TO with individual flow measurements being taken no less frequently than once every 15 minutes. The volumetric concentration of CO_2 from the vent of each Acid Gas Removal Unit shall be sampled, analyzed, and calculated according to 40 CFR §98.233(d). Fuel flow meters shall be recalibrated annually. The flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. The flow meters shall be accurate to ± 5.0 percent of the unit’s maximum flow.

31. The permit holder shall monitor and record the average hourly fuel consumption of each of the pre-heaters. Fuel flow meters shall be recalibrated annually. The fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. The flow meters shall be accurate to ± 5.0 percent of the unit’s maximum flow.

GHG- Piping, Valves, Connectors, Pumps, Agitators, and Compressors - 28VHP

32. Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment in pipeline quality natural gas service:

    A. The requirements of paragraphs F and G shall not apply where the operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

    The exempted components may be identified by one or more of the following methods:

    (1) piping and instrumentation diagram (PID);

    (2) a written or electronic database or electronic file;

    (3) color coding;

    (4) a form of weatherproof identification; or

(5) designation of exempted process unit boundaries.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked buried connectors shall be welded.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made readily available upon request. The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in subparagraph A above. If an unsafe-to-monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times. A difficult-to-monitor component for which quarterly monitoring is specified may instead be monitored annually.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open-ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

(1) a cap, blind flange, plug, or second valve must be installed on the line or valve; or

(2) the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an

approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once within the 72 hour period following the creation of the open ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings of 500 ppmv and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. If a relief valve is equipped with rupture disc, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity.

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed at least quarterly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown. The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR Part 60, Appendix A. The gas analyzer shall be calibrated with methane. Replacements for leaking components shall be re-monitored within 15 days of being placed back into methane service.

G. Except as may be provided for in the special conditions of this permit, all pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of methane from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting methane in excess of 500 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting methane in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

I. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I), the TCEQ Regional Manager and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. The instrument monitoring record shall include the time that monitoring took place for no less than 95% of the instrument readings recorded. Records of physical inspections shall be noted in the operator's log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC § 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS) and does not constitute approval of alternative standards for these regulations.

33. The permit holder shall minimize emissions from pressurized components and equipment containing GHG pollutants as follows:

A. Piping and valves in natural gas service within the operating area must be checked daily for leaks using AVO sensing for natural gas leaks.

B. The sulfur hexafluoride (SF_6)-enclosed circuit breakers used to prevent damage in the event of a power surge must be designed to meet the latest ANSI C37.013 standard for high-voltage circuit breakers. The circuit breakers must be guaranteed to achieve a SF_6 leak rate of 0.5% by weight or less annually.

(1) For EPN Circuit Breakers, SF_6 emissions shall be calculated annually (calendar year) in accordance with the mass balance approach provided in equation DD-1 of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use, 40 CFR Part 98, Subpart DD. Permittee shall not exceed insulated circuit breaker SF_6 capacity of 3,360 lbs.

(2) Permittee shall equip the circuit breakers with a low-pressure alarm and a low-pressure lockout. The SF_6 leak detection system shall be able to detect a leak of at least 1 lb per year.

(3) Permittee shall maintain a file of all records, data measurements, reports and documents related to the fugitive emission sources including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to compliance with the Monitoring and Quality Assurance and Quality Control procedures outlined in 40 CFR § 98.304.

GHG Continuous Demonstration of Compliance

34. Calculations and recordkeeping shall be the basis for demonstrating continuous compliance with the CO_2e emission limits and work practices identified in the permit and on the MAERT. 60 days after achieving commencement of commercial operation of each respective LNG train, but no later than 180 days after commencement of commercial operation of each LNG train, the permit holder shall compare a calendar month's emission rate of CO_2e to the limits in the MAERT. The permit holder shall submit a report, no later than 60 days following the time period identified above, to the TCEQ Regional Office identifying whether the data causes any concerns regarding the permit holder's ability to comply with the applicable limitations.

35. Emission calculation methodologies and monitoring and quality assurance/quality control requirements related to GHG emissions shall adhere to the applicable requirements in 40 CFR Part 98 and in this permit.

If any condition of this permit conflicts with applicable requirements in 40 CFR Part 98, then for the purposes of complying with this permit, the requirements in 40 CFR Part 98 shall govern and be the standard by which compliance shall be demonstrated. All fuels identified in this permit as authorized fuels for the combustion turbines, flare pilots, pre-heaters, and thermal oxidizers, with the exception of diesel and rich amine flash gas or other vent streams from the Acid Gas Removal Unit, shall be considered natural gas for purposes of calculating GHG emission in accordance with 40 CFR 98.

36. In lieu of the requirements of Special Condition No. 34 for a given turbine or TO, the permit holder may install, calibrate, maintain, and operate a CEMS for CO_2 emission measurements. If a CEMS is installed, the CEMS shall meet the specifications and test procedures for CO_2 emission monitoring system at stationary sources, 40 CFR Part 98; or meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 3

and follow the monitoring requirements of 40 CFR § 60.13. If a CEMS is installed, the permit holder shall also measure volumetric flow and install a data acquisition and handling system to record all measurements.

GHG Calculation Methodology

37. Calculations of emissions of CO_2, CH_4, and N_2O to determine compliance with the MAERT CO_2e emission limitation shall be calculated in the following manner by the end of the current month for the previous rolling 12-month basis.

A. Any referenced methodology of 40 CFR Part 98 is modified as follows

(1) References to annual measurements are to be construed as a rolling 12-month total if the variable is measured on a monthly or more frequent basis.

(2) References to annual measurements that are not measured at a frequency greater than one month (e.g. quarterly or semiannual) are to be construed as the average of the most recent measurements based on a rolling twelve-month period (e.g. average of 4 quarterly or 2 semiannual).

B. For each combustion turbine (EPN CT-COMP-1, CT-COMP-2, CT-COMP-3, CT-COMP-4, CT-COMP-5, CT-COMP-6, CT-COMP-7, CT-COMP-8, CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, and CT-GEN-9)

(1) Use the rolling 12-month total fuel flow rate.

(2) Use the methodology in 40 CFR § 98.33(a)(2)(i) (Equation C-2) with CO_2 converted to short tons.

(3) Use the default CH_4 and N_2O emission factors contained in Table C-2 and Equation C-9a of 40 CFR Part 98, and

C. For each TO (EPNs TO-1, TO-2, TO-3, and TO-4)

(1) For the acid gas stream, use the methodology in 40 CFR § 98.233(d)(2) (Equation W-3) to calculate CO_2 with $E_{a,CO2}$ converted to short tons.

(2) For the acid gas stream, to calculate unburned CH_4 emission use

(a) The rolling 12-month total flow rate of acid gas sent to the TO;

(b) A DRE of 99.9% for CH_4.

(3) Use the default CO_2, CH_4, and N_2O emission factors contained in Table C-1 and Table C-2 and Equation C-9a of 40 CFR Part 98 for TO fuel and pilot gas, and

D. For each flare system (EPNs M-FLARE and G-FLARE)

(1) To calculate CH_4 and CO_2 emissions, use the methodology in 40 CFR § 98.233(n)(4) – (6) with

(a) The rolling 12-month average CH_4 content and total volumetric gas flow to the flare and

(b) A DRE of 99%

(2) To calculate CO_2 emissions use

(a) The rolling 12-month average CO_2 content

(b) The rolling 12-month average total hydrocarbon content and a DRE of 99%

(3) To calculate N_2O emissions use

(a) The methodology in 40 CFR § 98.233(z)(2) (Equation W-40) and

(b) The rolling 12-month average volumetric gas flow, and

E. For the diesel-fired standby generators and fire water pump engines (EPNs ENG-GEN-1, ENG-GEN-2, ENG-GEN-3, ENG-GEN-4, ENG-FWP-1, and ENG-FWP-2)

(1) Use the default CO_2, CH_4, and N_2O emission factors contained in Table C-1 and Table C-2 and 40 CFR Part 98.33.

(2) Using hours of non-emergency runtime is acceptable if maximum fuel consumption is assumed, and

F. For the Pre-Heaters (EPN HTR-1 and HTR-2)

(1) Use the rolling 12-month total fuel flow rate.

(2) Use the methodology in 40 CFR § 98.33(a)(3)(iii) (Equation C-5) with CO_2 converted to short tons.

(3) Use the default CH_4 and N_2O emission factors contained in Table C-2 and Equation C-9a of 40 CFR Part 98, and

G. For Fugitive Equipment Leaks (EPN FUGITIVES)

(1) Use the methodology in 40 CFR § 98.233(q) with CH_4 converted to short tons.

38. Permittee shall calculate the CO_2e emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on November 29, 2013 (78 FR 71904).

39. Emissions calculations for each electric power generation combustion turbines may utilize calculation methodologies in 40 CFR Part 75 or 95 to show compliance with the lb CO_2/MWh emission rates in Special Condition No. 28. Calculation must be performed by the end of the current month for the previous rolling 12-month basis.

A. Calculate CO_2 emissions utilizing 40 CFR Part 98 referenced above in Special Condition No. 36.B.

B. Calculate CO_2 emissions utilizing 40 CFR Part 75.

(1) Heat input. Calculate the heat input in million Btus, using the measured fuel flow and the HHV of the fuel. Calculate the hourly heat input consistent with Equation F-20 and the procedures for determining the HHV, in Section 5.5.2 of 40 CFR Part 75, Appendix F. In this section, the HHV is referred to as the gross calorific value of gaseous fuel, GCV_g, and is expressed in Btu/100 scf.

(2) CO_2 emission rate. Calculate the CO_2 emission rate in short tons per hour, during all non-MSS periods of operation, in accordance with 40 CFR Part 75, Appendix G, section 2.3, Equation G-4, using:

(a) the default emission factor of 118.9 lb CO_2/MMBtu; or

(b) a custom emission factor determined in accordance with 40 CFR Part 75, Appendix F, section 3.3.6, Equation 7-b.

(3) Output-specific CO_2 emission rate. Calculate the output-specific CO_2 emission rate in lb CO_2/MWh by dividing the hourly CO_2 emission rate by the corresponding hourly gross output in MWh of the combustion turbine. Output-specific CO_2 emissions do not need to be calculated during periods of MSS.

(4) Calculate 12-month rolling data from hourly data. Monthly output-specific CO_2 emissions are the sum of the hourly CO_2 emissions for the month, excluding periods of MSS, divided by the sum of the hourly gross output for the same hourly periods. At the end of each calendar month, add the monthly CO_2 emissions to the monthly CO_2 emissions for the preceding 11 operating months and divide the resulting sum by the gross output in MWh for the same period.

(5) An operating month is any calendar month in which the combustion turbine is operated in normal operation for any time.

Additional GHG Recordkeeping Requirements

40. The following information must be maintained by the holder of this permit in a form suitable for inspection for a period of five years after collection and must be made available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:

A. Records sufficient to demonstrate compliance with 30 Texas Administrative Code § 116.164. Records shall be sufficient to demonstrate the amount of emissions of GHGs from the source as a result of construction, a physical change or a change in method of operation does not require authorization under 30 TAC §116.164(a).

B. Records for each combustion turbine (EPNs CT-COMP-1, CT-COMP-2, CT-COMP-3, CT-COMP-4, CT-COMP-5, CT-COMP-6, CT-COMP-7, CT-COMP-8,

CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, and CT-GEN-9) of:

(1) Monthly and rolling 12-month CO_2 and CO_2e emissions data in tons.

(2) Monthly and rolling 12-month fuel flow data.

C. Records of electrical generation from each electric power generation combustion turbines combustion turbine (EPNs CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, or CT-GEN-9) to show compliance with Special Condition No. 7.F.

D. For each thermal oxidizer (EPNs TO-1, TO-2, TO-3, and TO-4), records of:

(1) Hourly combustion chamber outlet temperature.

(2) Hourly exhaust oxygen content.

(3) Monthly, and rolling 12-month fuel consumption.

(4) Monthly, and rolling 12-month vent flow from each Acid Gas Removal Unit.

(5) Results of CO_2 sampling required by 40 CFR Part 98.233(d)(6).

E. For the pre-heaters (EPNs HTR-1 and HTR-2), records of:

(1) Monthly and rolling 12-month CO_2e emissions data in tons.

(2) Monthly and rolling 12-month fuel flow data.

F. For the flares (EPN M-FLARE and G-FLARE), records of:

(1) Monthly and rolling 12-month CO_2e emissions data in tons.

(2) Monthly and rolling 12-month vent gas flow measurement data.

G. For fugitive emissions (EPN FUG), records required by the monitoring program in Special Condition No. 32.

H. Records of parameters used in calculations and the calculations required in Special Condition Nos. 37 and 39.

I. If a CEMS is selected to measure CO_2 emissions from the combustion turbines and/or TOs pursuant to Special Condition No 36, then raw data files of all CEMS data shall be kept, including calibration checks, adjustments, and maintenance performed on these systems in a permanent form suitable for inspection.

Emission Sources - Maximum Allowable Emission Rates

Permit Numbers 158420 and PSDTX1572

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
M-FLARE	Marine Flare	NO_x	240.22	26.11
		CO	479.58	52.13
		VOC	4.72	0.69
		SO_2	1.30	0.14
		PM	0.01	0.01
		PM_{10}	0.01	0.01
		$PM_{2.5}$	0.01	0.01
G-FLARE	Ground Flare	NO_x	12.24	52.94
		CO	24.49	105.69
		VOC	3.24	5.32
		SO_2	0.07	0.33
		PM	0.13	0.55
		PM_{10}	0.13	0.55
		$PM_{2.5}$	0.13	0.55
G-FLARE	Ground Flare (MSS)	NO_x	1,706.74	368.66
		CO	3,407.29	735.97
		VOC	114.49	24.73
		SO_2	8.66	1.87
		PM	0.13	0.55
		PM_{10}	0.13	0.55
		$PM_{2.5}$	0.13	0.55

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
CT-COMP-1	Refrigeration Compressor Turbine1	NO_x	36.45	139.59
		NO_x (MSS)	96.02	-
		CO	61.62	238.46
		CO (MSS)	467.60	-
		VOC	2.82	11.00
		VOC (MSS)	33.40	-
		PM	11.07	42.15
		PM_{10}	11.07	42.15
		$PM_{2.5}$	11.07	42.15
		SO_2	10.24	2.60
		H_2SO_4	1.57	0.40
CT-COMP-2	Refrigeration Compressor Turbine 2	NO_x	36.45	139.59
		NO_x (MSS)	96.02	-
		CO	61.62	238.46
		CO (MSS)	467.60	-
		VOC	2.82	11.00
		VOC (MSS)	33.40	-
		PM	11.07	42.15
		PM_{10}	11.07	42.15
		$PM_{2.5}$	11.07	42.15
		SO_2	10.24	2.60
		H_2SO_4	1.57	0.40

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
CT-COMP-3	Refrigeration Compressor Turbine 3	NO_x	36.45	139.59
		NO_x (MSS)	96.02	-
		CO	61.62	238.46
		CO (MSS)	467.60	-
		VOC	2.82	11.00
		VOC (MSS)	33.40	-
		PM	11.07	42.15
		PM_{10}	11.07	42.15
		$PM_{2.5}$	11.07	42.15
		SO_2	10.24	2.60
		H_2SO_4	1.57	0.40
CT-COMP-4	Refrigeration Compressor Turbine 4	NO_x	36.45	139.59
		NO_x (MSS)	96.02	-
		CO	61.62	238.46
		CO (MSS)	467.60	-
		VOC	2.82	11.00
		VOC (MSS)	33.40	-
		PM	11.07	42.15
		PM_{10}	11.07	42.15
		$PM_{2.5}$	11.07	42.15
		SO_2	10.24	2.60
		H_2SO_4	1.57	0.40

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
CT-COMP-5	Refrigeration Compressor Turbine 5	NO_x	36.45	139.59
		NO_x (MSS)	96.02	-
		CO	61.62	238.46
		CO (MSS)	467.60	-
		VOC	2.82	11.00
		VOC (MSS)	33.40	-
		PM	11.07	42.15
		PM_{10}	11.07	42.15
		$PM_{2.5}$	11.07	42.15
		SO_2	10.24	2.60
		H_2SO_4	1.57	0.40
CT-COMP-6	Refrigeration Compressor Turbine 6	NO_x	36.45	139.59
		NO_x (MSS)	96.02	-
		CO	61.62	238.46
		CO (MSS)	467.60	-
		VOC	2.82	11.00
		VOC (MSS)	33.40	-
		PM	11.07	42.15
		PM_{10}	11.07	42.15
		$PM_{2.5}$	11.07	42.15
		SO_2	10.24	2.60
		H_2SO_4	1.57	0.40

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
CT-COMP-7	Refrigeration Compressor Turbine 7	NO_x	36.45	139.59
		NO_x (MSS)	96.02	-
		CO	61.62	238.46
		CO (MSS)	467.60	-
		VOC	2.82	11.00
		VOC (MSS)	33.40	-
		PM	11.07	42.15
		PM_{10}	11.07	42.15
		$PM_{2.5}$	11.07	42.15
		SO_2	10.24	2.60
		H_2SO_4	1.57	0.40
CT-COMP-8	Refrigeration Compressor Turbine 8	NO_x	36.45	139.59
		NO_x (MSS)	96.02	-
		CO	61.62	238.46
		CO (MSS)	467.60	-
		VOC	2.82	11.00
		VOC (MSS)	33.40	-
		PM	11.07	42.15
		PM_{10}	11.07	42.15
		$PM_{2.5}$	11.07	42.15
		SO_2	10.24	2.60
		H_2SO_4	1.57	0.40

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
CT-GEN-1	Generator Combustion Turbine 1	NO_x	7.37	28.21
		NO_x (MSS)	36.84	-
		CO	8.07	30.84
		CO (MSS)	22.43	-
		VOC	1.03	3.93
		VOC (MSS)	7.67	-
		PM	2.32	8.84
		PM_{10}	2.32	8.84
		$PM_{2.5}$	2.32	8.84
		SO_2	2.96	1.88
		H_2SO_4	0.45	0.29
		NH_3	5.46	20.78
		Formaldehyde	0.13	0.48
CT-GEN-2	Generator Combustion Turbine 2	NO_x	7.37	28.21
		NO_x (MSS)	36.84	-
		CO	8.07	30.84
		CO (MSS)	22.43	-
		VOC	1.03	3.93
		VOC (MSS)	7.67	-
		PM	2.32	8.84
		PM_{10}	2.32	8.84
		$PM_{2.5}$	2.32	8.84
		SO_2	2.96	1.88
		H_2SO_4	0.45	0.29
		NH_3	5.46	20.78
		Formaldehyde	0.13	0.48

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
CT-GEN-3	Generator Combustion Turbine 3	NO_x	7.37	28.21
		NO_x (MSS)	36.84	-
		CO	8.07	30.84
		CO (MSS)	22.43	-
		VOC	1.03	3.93
		VOC (MSS)	7.67	-
		PM	2.32	8.84
		PM_{10}	2.32	8.84
		$PM_{2.5}$	2.32	8.84
		SO_2	2.96	1.88
		H_2SO_4	0.45	0.29
		NH_3	5.46	20.78
		Formaldehyde	0.13	0.48
CT-GEN-4	Generator Combustion Turbine 4	NO_x	7.37	28.21
		NO_x (MSS)	36.84	-
		CO	8.07	30.84
		CO (MSS)	22.43	-
		VOC	1.03	3.93
		VOC (MSS)	7.67	-
		PM	2.32	8.84
		PM_{10}	2.32	8.84
		$PM_{2.5}$	2.32	8.84
		SO_2	2.96	1.88
		H_2SO_4	0.45	0.29
		NH_3	5.46	20.78
		Formaldehyde	0.13	0.48

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
CT-GEN-5	Generator Combustion Turbine 5	NO_x	7.37	28.21
		NO_x (MSS)	36.84	-
		CO	8.07	30.84
		CO (MSS)	22.43	-
		VOC	1.03	3.93
		VOC (MSS)	7.67	-
		PM	2.32	8.84
		PM_{10}	2.32	8.84
		$PM_{2.5}$	2.32	8.84
		SO_2	2.96	1.88
		H_2SO_4	0.45	0.29
		NH_3	5.46	20.78
		Formaldehyde	0.13	0.48
CT-GEN-6	Generator Combustion Turbine 6	NO_x	7.37	28.21
		NO_x (MSS)	36.84	-
		CO	8.07	30.84
		CO (MSS)	22.43	-
		VOC	1.03	3.93
		VOC (MSS)	7.67	-
		PM	2.32	8.84
		PM_{10}	2.32	8.84
		$PM_{2.5}$	2.32	8.84
		SO_2	2.96	1.88
		H_2SO_4	0.45	0.29
		NH_3	5.46	20.78
		Formaldehyde	0.13	0.48

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
CT-GEN-7	Generator Combustion Turbine 7	NO_x	7.37	28.21
		NO_x (MSS)	36.84	-
		CO	8.07	30.84
		CO (MSS)	22.43	-
		VOC	1.03	3.93
		VOC (MSS)	7.67	-
		PM	2.32	8.84
		PM_{10}	2.32	8.84
		$PM_{2.5}$	2.32	8.84
		SO_2	2.96	1.88
		H_2SO_4	0.45	0.29
		NH_3	5.46	20.78
		Formaldehyde	0.13	0.48
CT-GEN-8	Generator Combustion Turbine 8	NO_x	7.37	28.21
		NO_x (MSS)	36.84	-
		CO	8.07	30.84
		CO (MSS)	22.43	-
		VOC	1.03	3.93
		VOC (MSS)	7.67	-
		PM	2.32	8.84
		PM_{10}	2.32	8.84
		$PM_{2.5}$	2.32	8.84
		SO_2	2.96	1.88
		H_2SO_4	0.45	0.29
		NH_3	5.46	20.78
		Formaldehyde	0.13	0.48

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
CT-GEN-9	Generator Combustion Turbine 9	NO_x	7.37	28.21
		NO_x (MSS)	36.84	-
		CO	8.07	30.84
		CO (MSS)	22.43	-
		VOC	1.03	3.93
		VOC (MSS)	7.67	-
		PM	2.32	8.84
		PM_{10}	2.32	8.84
		$PM_{2.5}$	2.32	8.84
		SO_2	2.96	1.88
		H_2SO_4	0.45	0.29
		NH_3	5.46	20.78
		Formaldehyde	0.13	0.48
HTR-1	Gas Turbine Preheater 1	NO_x	0.19	0.82
		CO	0.31	1.37
		VOC	0.02	0.09
		SO_2	0.01	0.02
		PM	0.03	0.12
		PM_{10}	0.03	0.12
		$PM_{2.5}$	0.03	0.12
HTR-2	Gas Turbine Preheater 2	NO_x	0.19	0.82
		CO	0.31	1.37
		VOC	0.02	0.09
		SO_2	0.01	0.02
		PM	0.03	0.12
		PM_{10}	0.03	0.12
		$PM_{2.5}$	0.03	0.12

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
TO-1	Thermal Oxidizer 1	NO_x	4.68	20.50
		CO	6.42	28.14
		VOC	0.43	1.86
		PM	0.58	2.55
		PM_{10}	0.58	2.55
		$PM_{2.5}$	0.58	2.55
		SO_2	1.28	5.73
		H_2SO_4	0.10	0.44
TO-2	Thermal Oxidizer 2	NO_x	4.68	20.50
		CO	6.42	28.14
		VOC	0.43	1.86
		PM	0.58	2.55
		PM_{10}	0.58	2.55
		$PM_{2.5}$	0.58	2.55
		SO_2	1.28	5.73
		H_2SO_4	0.10	0.44
TO-3	Thermal Oxidizer 3	NO_x	4.68	20.50
		CO	6.42	28.14
		VOC	0.43	1.86
		PM	0.58	2.55
		PM_{10}	0.58	2.55
		$PM_{2.5}$	0.58	2.55
		SO_2	1.28	5.73
		H_2SO_4	0.10	0.44

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
TO-4	Thermal Oxidizer 4	NO_x	4.68	20.50
		CO	6.42	28.14
		VOC	0.43	1.86
		PM	0.58	2.55
		PM_{10}	0.58	2.55
		$PM_{2.5}$	0.58	2.55
		SO_2	1.28	5.73
		H_2SO_4	0.10	0.44
ENG-GEN-1	Diesel Standby Generator 1	NO_x	47.39	0.57
		CO	27.78	0.33
		VOC	3.40	0.04
		PM	1.59	0.02
		PM_{10}	1.59	0.02
		$PM_{2.5}$	1.59	0.02
		SO_2	0.06	<0.01
ENG-GEN-2	Diesel Standby Generator 2	NO_x	47.39	0.57
		CO	27.78	0.33
		VOC	3.40	0.04
		PM	1.59	0.02
		PM_{10}	1.59	0.02
		$PM_{2.5}$	1.59	0.02
		SO_2	0.06	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
ENG-GEN-3	Diesel Standby Generator 3	NO_x	47.39	0.57
		CO	27.78	0.33
		VOC	3.40	0.04
		PM	1.59	0.02
		PM_{10}	1.59	0.02
		$PM_{2.5}$	1.59	0.02
		SO_2	0.06	<0.01
ENG-GEN-4	Diesel Standby Generator 4	NO_x	47.39	0.57
		CO	27.78	0.33
		VOC	3.40	0.04
		PM	1.59	0.02
		PM_{10}	1.59	0.02
		$PM_{2.5}$	1.59	0.02
		SO_2	0.06	<0.01
ENG-FWP-1	Diesel Fire Water Pump 1	NO_x	8.89	0.17
		CO	4.97	0.10
		VOC	0.64	0.01
		PM	0.30	0.01
		PM_{10}	0.30	0.01
		$PM_{2.5}$	0.30	0.01
		SO_2	0.01	<0.01
ENG-FWP-2	Diesel Fire Water Pump 2	NO_x	8.89	0.17
		CO	4.97	0.10
		VOC	0.64	0.01
		PM	0.30	0.01
		PM_{10}	0.30	0.01
		$PM_{2.5}$	0.30	0.01
		SO_2	0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lb/hr	TPY(5)
TRK-LOAD-1	Condensate Truck Loading 1 Fugitives	VOC	1.15	0.73
TRK-LOAD-2	Process Wastewater Truck Loading Fugitives	VOC	<0.01	<0.01
TK-DSLF-1	Diesel Storage Tank for FWP-1	VOC	0.03	<0.01
TK-DSLF-2	Diesel Storage Tank for FWP-2	VOC	0.03	<0.01
TK-DSLG-1	Diesel Storage Tank for Standby Generator 1	VOC	0.20	<0.01
TK-DSLG-2	Diesel Storage Tank for Standby Generator 2	VOC	0.20	<0.01
TK-DSLG-3	Diesel Storage Tank for Standby Generator 3	VOC	0.20	<0.01
TK-DSLG-4	Diesel Storage Tank for Standby Generator 4	VOC	0.20	<0.01
TK-DSL-1	Diesel Storage Tank 1	VOC	0.46	0.01
TK-LAMINE-1	Lean Amine Storage Tank 1	VOC	<0.01	<0.01
TK-FAMINE-1	Fresh Amine Storage Tank 1	VOC	<0.01	<0.01
TK-HOTOIL-1	Hot Oil Storage Tank 1	VOC	0.04	<0.01
TK-SLOPOIL-1	Slop Oil Storage Tank 1	VOC	0.57	<0.01
FUGITIVES	Equipment Leak Fugitives (6)	VOC	9.88	43.29
AMFUG	Ammonia Piping Fugitives (6)	NH_3	<0.01	0.03
TK-PWW-1	Process Wastewater Storage Tank	VOC	<0.01	<0.01

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
CO - carbon monoxide
H_2SO_4 - sulfuric acid
NH_3 - ammonia
MSS - maintenance, startup, and shutdown emissions
(4) Planned maintenance, startup and shutdown (MSS) lb/hour emissions for all pollutants are authorized even if not specifically identified as MSS. During any clock hour that includes one or more minutes of planned MSS, that pollutant's maximum hourly emission rate shall apply during that clock hour. Continuous demonstration of compliance with the lb/hr emission limits for NO_x, CO, and NH_3, from any of the refrigeration or generation turbines equipped with CEMS or PEMS shall be based upon a three-hour rolling average.
(5) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period. Annual emission rates for each source include planned MSS emissions, unless otherwise noted.

Emission Sources - Maximum Allowable Emission Rates

(6) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.

Date: Xxx xx, 2020

Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPSDTX198

This table lists the maximum allowable emission rates of greenhouse gas (GHG) emissions, as defined in Title 30 Texas Administrative Code § 101.1, for sources of GHG air contaminants on the applicant's property authorized by this permit. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
M-FLARE	Marine Flare	CO_2	24,088.34
		CH_4	77.34
		N_2O	0.01
		CO_2e	26,024
G-FLARE	Ground Flare	CO_2	42,777.97
		CH_4	125.56
		N_2O	0.02
		CO_2e	45,923
G-FLARE	Ground Flare (MSS)	CO_2	294,618.52
		CH_4	1,082.16
		N_2O	<0.01
		CO_2e	321,673
CT-COMP-1	Refrigeration Compressor Turbine1	CO_2	503,996.77
		CH_4	9.50
		N_2O	0.95
		CO_2e	504,517
CT-COMP-2	Refrigeration Compressor Turbine2	CO_2	503,996.77
		CH_4	9.50
		N_2O	0.95
		CO_2e	504,517
CT-COMP-3	Refrigeration Compressor Turbine3	CO_2	503,996.77
		CH_4	9.50
		N_2O	0.95
		CO_2e	504,517

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
CT-COMP-4	Refrigeration Compressor Turbine4	CO_2	503,996.77
		CH_4	9.50
		N_2O	0.95
		CO_2e	504,517
CT-COMP-5	Refrigeration Compressor Turbine5	CO_2	503,996.77
		CH_4	9.50
		N_2O	0.95
		CO_2e	504,517
CT-COMP-6	Refrigeration Compressor Turbine6	CO_2	503,996.77
		CH_4	9.50
		N_2O	0.95
		CO_2e	504,517
CT-COMP-7	Refrigeration Compressor Turbine7	CO_2	503,996.77
		CH_4	9.50
		N_2O	0.95
		CO_2e	504,517
CT-COMP-8	Refrigeration Compressor Turbine8	CO_2	503,996.77
		CH_4	9.50
		N_2O	0.95
		CO_2e	504,517
CT-GEN-1	Generator Combustion Turbine 1	CO_2	156,749.07
		CH_4	2.95
		N_2O	0.30
		CO_2e	156,912
CT-GEN-2	Generator Combustion Turbine 2	CO_2	156,749.07
		CH_4	2.95
		N_2O	0.30
		CO_2e	156,912

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
CT-GEN-3	Generator Combustion Turbine 3	CO_2	156,749.07
		CH_4	2.95
		N_2O	0.30
		CO_2e	156,912
CT-GEN-4	Generator Combustion Turbine 4	CO_2	156,749.07
		CH_4	2.95
		N_2O	0.30
		CO_2e	156,912
CT-GEN-5	Generator Combustion Turbine 5	CO_2	156,749.07
		CH_4	2.95
		N_2O	0.30
		CO_2e	156,912
CT-GEN-6	Generator Combustion Turbine 6	CO_2	156,749.07
		CH_4	2.95
		N_2O	0.30
		CO_2e	156,912
CT-GEN-7	Generator Combustion Turbine 7	CO_2	156,749.07
		CH_4	2.95
		N_2O	0.30
		CO_2e	156,912
CT-GEN-8	Generator Combustion Turbine 8	CO_2	156,749.07
		CH_4	2.95
		N_2O	0.30
		CO_2e	156,912
CT-GEN-9	Generator Combustion Turbine 9	CO_2	156,749.07
		CH_4	2.95
		N_2O	0.30
		CO_2e	156,912

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
HTR-1	Gas Turbine Preheater 1	CO_2	1,946.97
		CH_4	0.04
		N_2O	<0.01
		CO_2e	1,951
HTR-2	Gas Turbine Preheater 2	CO_2	1,946.97
		CH_4	0.04
		N_2O	<0.01
		CO_2e	1,951
TO-1	Thermal Oxidizer 1	CO_2	472,886
		CH_4	1.09
		N_2O	0.08
		CO_2e	472936
TO-2	Thermal Oxidizer 2	CO_2	472,886
		CH_4	1.09
		N_2O	0.08
		CO_2e	472936
TO-3	Thermal Oxidizer 3	CO_2	472,886
		CH_4	1.09
		N_2O	0.08
		CO_2e	472936
TO-4	Thermal Oxidizer 4	CO_2	472,886
		CH_4	1.09
		N_2O	0.08
		CO_2e	472936
ENG-GEN-1	Diesel Standby Generator 1	CO_2	66.07
		CH_4	<0.01
		N_2O	<0.01
		CO_2e	67

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
ENG-GEN-2	Diesel Standby Generator 2	CO_2	66.07
		CH_4	<0.01
		N_2O	<0.01
		CO_2e	67
ENG-GEN-3	Diesel Standby Generator 3	CO_2	66.07
		CH_4	<0.01
		N_2O	<0.01
		CO_2e	67
ENG-GEN-4	Diesel Standby Generator 4	CO_2	66.07
		CH_4	<0.01
		N_2O	<0.01
		CO_2e	67
ENG-FWP-1	Diesel Fire Water Pump 1	CO_2	20.13
		CH_4	<0.01
		N_2O	<0.01
		CO_2e	21
ENG-FWP-2	Diesel Fire Water Pump 2	CO_2	20.13
		CH_4	<0.01
		N_2O	<0.01
		CO_2e	21
FUGITIVES	Equipment Leak Fugitives (5)	CO_2	17.03
		CH_4	88.34
		CO_2e	2,226
Circuit Breakers	Circuit Breakers (5)	SF_6	0.01
		CO_2e	192

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) CO_2 - carbon dioxide
N_2O - nitrous oxide
CH_4 - methane
SF_6 - sulfur hexafluoride
CO_2e - carbon dioxide equivalents, based on the following Global Warming Potentials from 40 CFR Part 98, subpart A, Table A-1, as published on November 29, 2013 (78 FR71904): CO_2 (1), CH_4 (25), N_2O (298), and SF_6 (22,800)

Emission Sources - Maximum Allowable Emission Rates

(4) Compliance with annual CO_2e emission limits (tons per year) is based on a 12-month rolling period. Annual emission limits includes normal and planned maintenance, startup, and shutdown (MSS) emissions. For all non-CO_2e GHG emissions, listed emission rates are given for informational purposes only and do not constitute an enforceable limit.
(5) Fugitive emission rates are estimates and are enforceable through compliance with the applicable special conditions and permit application representations.

Date: Xxx xx, 2020

Preliminary Determination Summary

Port Arthur LNG, LLC
Permit Numbers 158420, PSDTX1572, and GHGPSDTX198

I. Applicant

Port Arthur LNG LLC
2925 Briarpark Drive Ste 900
Houston, TX 77042-3781

II. Project Location

The proposed site is located on TX 87, approximately 5.3 miles south of the intersection of TX 82 and TX 87 in Port Arthur, Jefferson County, Texas 77642.

III. Project Description

Port Arthur LNG, LLC (PALNG) proposes to construct and operate a natural gas liquefaction and export terminal near Port Arthur, Jefferson County and the Sabine Pass in Southeast Texas. The proposed liquefaction plant will consist of four liquefaction trains, each capable of producing 6.76 million metric tonnes per annum of liquefied natural gas (LNG). Each LNG train will consist of one propane and one mixed refrigeration compression turbine and an Acid Gas Removal Unit (AGRU). Pipeline quality natural gas will be delivered from interconnecting intrastate pipeline systems. The natural gas will be treated to remove acid gases (carbon dioxide and sulfur compounds) with an amine treatment process. Emissions from the AGRU will be controlled with a thermal oxidizer. Water, mercury, and heavy hydrocarbons will also be removed from the natural gas. The treated natural gas is then sent to the liquefaction process where the gas is cooled to become a liquid. The LNG will then be stored in one of three LNG storage tanks and loaded onto a marine vessel for export at the marine berthing area. Emissions from routine maintenance, startup, and shutdown (MSS) activities are included in the permit application and have been reviewed.

The proposed project will include the following new emission points:

- Eight GE Frame 7EA gas-fired refrigeration compressor turbines, four with waste heat recovery
- Nine GE PGT25+G4 simple cycle gas-fired combustion turbine electric generating units
- One marine flare
- One ground flare
- Two gas-fired fuel pre-heaters
- Four thermal oxidizers
- Four diesel-fired engine standby generators
- Two diesel-fired engine fire water pumps

- Seven diesel storage tanks
- Two amine storage tanks
- Two oil storage tanks
- Fugitive emissions

IV. Emissions

The table below summarizes proposed maximum annual emissions in tons per year (TPY) for the project, including routine MSS emissions. These emissions include nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compounds (VOC), particulate matter (PM), PM less than 10 microns in average diameter (PM_{10}), PM less than 2.5 microns in average diameter ($PM_{2.5}$), sulfur dioxide (SO_2), sulfuric acid (H_2SO_4) mist, ammonia (NH_3), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), carbon dioxide (CO_2) and the carbon dioxide equivalent (CO_2e) of all greenhouse gases (GHG) emitted. The pollutants NO_x, CO, PM_{10}, $PM_{2.5}$, and SO_2 are criteria pollutants, for which a national ambient air quality standard (NAAQS) has been promulgated. In addition, NO_x and VOC are regulated as criteria pollutants for the NAAQS pollutant ozone, which forms in the atmosphere as a reaction of NO_x and VOC emissions.

Table 1. PALNG Project Emission Summary

Air Contaminant	Proposed Allowable Emission Rates (tpy)
VOC	206.06
NO_x	1,904.58
SO_2	63.02
CO	3,195.85
$PM/PM_{10}/PM_{2.5}$	428.41
H_2SO_4	7.59
NH_3	187.05
CO_2	7,699,960
CH_4	1,480.4
SF_6	0.01
N_2O	10.7
CO_2 Equivalents (CO_2e)	7,741,044

CO2e - carbon dioxide equivalents based on global warming potentials of CH_4 = 25, N_2O = 298, SF_6=22,800.

Predicted ground level concentrations for these pollutants identified in the table are discussed in Section VII below. The listed PM, PM_{10}, and $PM_{2.5}$ emissions include filterable and condensable particulate matter.

V. Federal Applicability

The PALNG terminal will be located in Jefferson County, which is classified as an attainment or unclassified area for all criteria pollutants. Because the ambient air in the county where the facility will be located is considered to attain the NAAQS, federal nonattainment permit review does not apply. The table below summarizes annual project emissions for each federally regulated new source review (NSR) pollutant and whether PSD review is triggered for the pollutant.

The PALNG terminal is considered a major source under the PSD program, since it has the potential to emit over the PSD major source threshold for at least one regulated pollutant. The project emissions for nitrogen oxides (NO_x), carbon monoxide (CO), and particulate matter, including particulate matter including particulate matter less than 10 microns and less than 2.5 microns in diameter ($PM/PM_{10}/PM_{2.5}$) are above the major source threshold level. As a major source for CO, NO_x and $PM/PM_{10}/PM_{2.5}$, PALNG also triggers PSD for VOC, SO_2 and H_2SO_4, since emissions of these pollutants are above their respective significance levels. The net emissions increase of greenhouse gases (GHG) will also exceed the 75,000 TPY significance level; therefore, PALNG is also required to obtain a PSD permit for GHG.

Table 2. PSD Pollutant Applicability to PALNG Project Emission Summary

Pollutant	Project Emissions (tpy)	Major Source Trigger (tpy)	PSD Significant Emission Rate (tpy)	PSD Triggered Y/N
VOC	206.06	250	40	Y
NO_x	1,904.58	250	40	Y
SO_2	63.02	250	40	Y
CO	3,195.85	250	100	Y
PM	428.41	250	25	Y
PM_{10}	428.41	250	15	Y
$PM_{2.5}$	428.41	250	10	Y

Pollutant	Project Emissions (tpy)	Major Source Trigger (tpy)	PSD Significant Emission Rate (tpy)	PSD Triggered Y/N
H_2SO_4	7.59	250	7	Y
CO_2e	7,741,044	--	75,000	Y

VI. Control Technology Review

Emission sources for the proposed project consist of: eight GE Frame 7EA gas-fired refrigeration compressor turbines (four with waste heat recovery), nine GE PGT25+G4 simple cycle gas-fired combustion turbine electric generating units, one marine flare, one ground flare, two gas-fired fuel pre-heaters, four thermal oxidizers, four diesel-fired engine standby generators, two diesel-fired engine fire water pumps, seven diesel storage tanks, two amine storage tanks, two oil storage tanks, and fugitives sources from natural gas and ammonia piping, and circuit breakers. As part of the best available control technology (BACT) review process, the Texas Commission on Environmental Quality (TCEQ) evaluates information from the Environmental Protection Agency's (EPA's) RACT/BACT/LAER Clearinghouse (RBLC), on-going permitting in Texas and other states, and the TCEQ's continuing review of emissions control developments.

The TCEQ performed an analysis of the applicant's proposed BACT for each emission source. The record of these BACT determinations is in the Preliminary Determination Summary (PDS) that is a part of the record for this permit. PALNG used EPA's "top-down" and the TCEQ's three tier BACT process to evaluate BACT for the emission sources identified above.

In addition to a review of control technology for steady state operations, the BACT analyses include MSS emissions and the numerical emission limits and work practices in the draft permit reflect this analysis. BACT for each pollutant include the numerical limits in the Maximum Allowable Emission Rate Table (MAERT).

Combustion Turbines for Refrigeration Compression

NO_x Emissions

NO_x will be controlled by dry low NO_x (DLN) burners to 9.0 ppmvd @ 15% O_2 on a 24-hour rolling average. This is BACT for the combustion turbines used for refrigeration compression. PALNG identified and evaluated the following NO_x reduction options: $SCONO_x$, SCR, and Selective Non-Catalytic Reduction (SNCR), DLN burners, water injection, and good combustion practices. $SCONO_x$

and SNCR were eliminated due to technical infeasibility. SCR was eliminated due to economic unreasonableness. SCR was estimated to cost between \$20,454 and \$27,800 per ton of NO_x removed. The use of DLN burners controlled to 9 ppmvd were selected for BACT. Water injection was not selected for BACT since it is less effective at reducing NO_x than DLN. A review of the RBLC and recently issued permits for refrigeration compressor combustion turbines indicates NO_x BACT ranging from 5 to 25 ppm. The RBLC review confirms that the controls proposed by PALNG are consistent with recent BACT decisions and satisfies BACT.

CO Emissions

CO emissions are the result of incomplete combustion of the carbon in a fuel. CO emissions can be reduced by combustion control techniques or by post combustion controls. Combustion control techniques include the incorporation of design and good combustion practices of maintaining proper air to fuel ratios, adequate residence time and temperature. Post-combustion CO control technologies use a catalyst to oxidize CO to CO_2. PALNG identified and evaluated oxidation catalyst and good combustion practices as CO reduction options. Oxidation catalyst was eliminated due to economic unreasonableness. Oxidation catalyst was estimated to cost approximately \$5,005 per ton of CO removed. The use of good combustion practices with CO emissions limited to 25 ppmvd @15% O_2 on a 3-hour rolling average was selected as BACT. A review of the RBLC and recently issued permits for refrigeration compressor combustion turbines indicates CO BACT ranged from 25 to 43.6 ppmvd. The RBLC review confirms that the controls proposed by PALNG are consistent with recent BACT decisions and satisfies BACT.

VOC Emissions

VOC emissions result from the incomplete combustion of the natural gas. VOC emissions can be reduced by combustion control techniques or by post-combustion controls. Combustion control techniques include the incorporation of design and good combustion practices of maintaining proper air to fuel ratios, adequate residence time and temperature. Post-combustion VOC control technologies use a catalyst to oxidize VOC. Oxidation catalyst was eliminated due to economic unreasonableness. Oxidation catalyst was estimated to cost approximately \$110,902 per ton of VOC removed. PALNG will utilize good combustion practices to limit VOC stack concentrations to 2 ppmvd @ 15% O_2 on a 3-hour rolling average. A review of the RBLC for refrigeration compression combustion turbines identified good combustion practices as the most prevalent control selected for BACT. The RBLC review confirms that the VOC controls proposed by PALNG are consistent with recent BACT decisions and satisfies BACT.

$PM/PM_{10}/PM_{2.5}$ Emissions

$PM/PM_{10}/PM_{2.5}$ is emitted from combustion processes as a result of the presence of ash and other inorganic constituents contained in the fuel, particulate matter in the inlet air, and incomplete combustion of the organic constituents in the fuel. Because the refrigeration combustion turbines will only fire fuel gas and natural gas, $PM/PM_{10}/PM_{2.5}$ emissions will primarily be limited to the incomplete combustion. A search of the RBLC database shows that no add-on controls have been required for gas-fired combustion turbines to control $PM/PM_{10}/PM_{2.5}$. Therefore, the use of fuel gas and pipeline-quality natural gas and the application of good combustion controls is BACT for $PM/PM_{10}/PM_{2.5}$.

SO_2 and H_2SO_4 Emissions

Emissions of SO_2 will occur as a result of oxidation of sulfur in the gas fired in the turbines, with the majority of the sulfur converted to SO_2. H_2SO_4 is formed through subsequent reactions in air affecting a fraction of the SO_2. The formation of SO_2 will be minimized by using low sulfur fuel gas and pipeline-quality natural gas with a sulfur content not exceeding 3 grain sulfur per 100 standard cubic feet on an hourly basis and 0.5 grains sulfur per 100 standard cubic feet on an annual average basis. A search of the RBLC for refrigeration compression combustion turbines did not show any post-combustion SO_2 control technologies. The RBLC showed that limitation on the fuel sulfur content has been accepted as BACT for SO_2. H_2SO_4 formation is limited by reducing SO_2 emissions. Therefore, the use of low sulfur fuel gas and natural gas with the sulfur contents listed above satisfies BACT for SO_2 and H_2SO_4 emissions.

GHG Emissions

As shown on the MAERT, the main GHG pollutant from the turbines is CO_2 which is about 99.9% of GHG emissions. BACT was based on control of CO_2. Unlike turbines that are attached to a generator to make electricity, there is not an accurate measure of instantaneous horsepower produced when driving a compressor, therefore, a numerical BACT limit which includes output for a turbine in compressor service is inappropriate. A power generation turbine can continuously measure megawatts produced at the generator terminals. A turbine driving a compressor could estimate the current horsepower, but not directly measure it like electricity. Reviews of other LNG facilities show that BACT reviews addressed technology selection and required low-carbon fuel such as natural gas.

PALNG identified and evaluated the following GHG control options for the refrigeration compression combustion turbines: carbon capture and storage

(CCS), the use of low carbon fuels, design energy efficiency, and operational energy efficiency. CCS was eliminated in the early stages of the BACT analysis due to technical infeasibility. CCS has never been demonstrated or utilized on a simple cycle gas-fired combustion turbine. For GHG BACT, PALNG selected the use of low carbon fuels, design energy efficiency, and operational energy efficiency. PALNG is also required to comply with CO_2e emission rates listed in the MAERT and will be limited to an hourly CO_2 emission rate limit during MSS. PALNG will conduct periodic maintenance to optimize thermal efficiency, utilize good combustion practices to maximize thermal efficiency, and will operate with optimum excess oxygen for efficient combustion.

PALNG designed the project to provide safe and reliable commercial production of LNG for export using proven and demonstrated technologies. The design was carefully selected to meet PALNG business objectives. PALNG plans to select Air Products and Chemicals Inc. proprietary C3MR™ liquefaction technology based on prior use of this technology and financial requirements necessary for commercial LNG project development. PALNG matched the power requirements of the refrigerant compressors with the turbine models selected. Combustion turbines used for electric generations were selected based upon size, efficiency, reliability and load following aspects of those turbines. PALNG will also install waste heat recovery coils in the exhaust in each of the four propane compressor combustion turbines to heat oil which will be circulated to the process units, thereby increasing overall efficiency. Additional waste heat is not able to be used in the proposed plant design.

The control methodologies accepted as BACT for GHG are consistent with recently issued GHG PSD permits for other refrigeration compression combustion turbines used at LNG facilities.

Turbine MSS Emissions

Operation of the turbines will result in emissions from planned startup and shutdowns that are being authorized in this permit. The combustion turbines will be started up and shut down in a manner that minimizes the emissions during these events. BACT will be achieved by minimizing the duration of the startup and shutdown events, engaging the pollution control equipment (e.g., the SCR system in the combustion turbines used for electric power generation and optimizing DLN combustors in the combustion turbines used for refrigeration compression) as soon as practicable (based on vendor recommendations and guarantees), and meeting the emissions limitations on the MAERT. The hourly emission limits are based on turbine vendor information. The special conditions of the permit limit the duration of each startup and shutdown to 60 minutes. Emissions from turbine maintenance are subject to the hourly emission limits for MSS. Because turbine maintenance is not conducted frequently, and annual limits for normal operation are sufficiently conservative, maximum annual emission limits for normal operation are large enough to accommodate both normal operation and maintenance.

Combustion Turbines for Electric Power Generation

NO_x Emissions

Combustion Turbine (GE PGT25+G4): NO_x will be controlled by selective catalytic reduction (SCR) and low NO_x burners to 5.0 ppmvd @ 15% O_2. PALNG identified and evaluated the following NO_x reduction options: $SCONO_x$, SCR, and Selective Non-Catalytic Reduction (SNCR), DLN burners, water injection, and good combustion practices. $SCONO_x$ and SNCR were eliminated due to technical infeasibility. PALNG will utilize DLN and SCR to control NO_x emissions. The turbines selected by PALNG are aero derivative turbines and will operate in simple cycle. A review of the RBLC and recently issued permits for simple cycle combustion turbines used to produce electricity indicates NO_x BACT ranging from 2.5 to 25 ppmvd. The RBLC review confirms that the controls proposed by PALNG are consistent with recent BACT decisions and satisfies BACT.

CO and VOC Emission

PALNG identified and evaluated oxidation catalyst and good combustion practices as CO reduction options. Oxidation catalyst and good combustion controls were selected as BACT for the combustion turbines used for electric power generation. The selection of oxidation catalyst for CO control will also reduce VOC emissions. CO and VOC emission concentration will be limited to 9 and 2 ppmvd respectively, both @ 15% O_2 on a 3-hour rolling average. A review of the RBLC and recently issued permits for simple cycle combustion turbines used in electric power generation indicates CO BACT ranging from 4 to 63 ppmvd. Good combustion practices were the most prevalent method of control listed for VOC emissions in the RBLC. The RBLC review confirms that the controls proposed by PALNG are consistent with recent BACT decisions and satisfies BACT.

$PM/PM_{10}/PM_{2.5}$ Emissions, Sulfur Compound Emissions, and MSS Emissions

The BACT analysis, RBLC results, and resulting selection of BACT for the combustion turbines used for electric power generation are similar to the combustion turbines used for refrigeration compression identified above for $PM/PM_{10}/PM_{2.5}$ emissions, sulfur compound emissions, and MSS emissions. PALNG will use pipeline-quality natural gas and the application of good combustion controls as BACT for $PM/PM_{10}/PM_{2.5}$ emissions. PALNG will use of low sulfur natural gas with the sulfur contents listed above to satisfy BACT for SO_2 and H_2SO_4 emissions. PALNG will utilize the work practices identified above and will be limited to the emission rates listed in the MAERT as BACT during periods of MSS.

Greenhouse Gas (GHG) Emissions

The BACT analysis and resulting selection of BACT for the combustion turbines used for electric power generation is similar to the BACT for combustion turbines used for refrigeration compression identified above for GHG emissions. PALNG selected the use of low carbon fuels, design energy efficiency (turbine), and operational energy efficiency for GHG BACT. PALNG is also required to comply with CO_2e emission rates listed in the MAERT, reflecting GHG controls, and will be limited to an hourly CO_2 emission rate limit during MSS. Additionally, output based numerical BACT limits for the turbines in electrical power generation service are included in the permit, because electrical output can continuously be measured. Emissions of carbon dioxide (CO_2) from each turbine will not exceed 1,060 pounds per megawatt-hour (lbs/MWh). The permit contains an enforceable limit on electrical output that can be sold to the electric grid to ensure the combustion turbines in electrical power service will not be subject to NSPS Subpart TTTT. The GHG control methods proposed by PALNG have been accepted as BACT in recently issued GHG PSD permits for other combustion turbines used for power generation and satisfy BACT.

Thermal Oxidizers/Amine Treatment System

Thermal oxidizers are control devices that will control acid gas streams from the AGRU, the H_2S Scavenger Unit, and emissions associated with the condensate storage and truck loading. PALNG proposed the thermal oxidizers will achieve 99.9% destruction and removal efficiency (DRE) for VOC and sulfur compounds. PALNG will use low NO_x burners that achieve an emission rate of 0.06 lb/MMBtu as BACT for NO_x. SCR was identified and evaluated as a potential control option, but was rejected due to technical infeasibility. PALNG will utilize good combustion practices for control of all other pollutants. The thermal oxidizers will meet the design, operational, monitoring, recordkeeping and testing requirements necessary to claim 99.9 % DRE. PALNG will maintain a minimum operating temperature of 1400 degrees F with a residence time of one second and will continuously monitor and record the combustion chamber temperature. A review of the RBLC database and recently permitted thermal oxidizers identified good combustion practices and the use of low NO_x burners as potentially applicable controls. PALNG BACT proposal for the thermal oxidizers is consistent with recent BACT determinations and satisfies BACT.

PALNG identified and evaluated the following GHG control options for the thermal oxidizers (TO): CCS, design energy efficiency, and operational efficiency. CCS was not selected as a control option for the thermal oxidizers due to technical infeasibility. CCS has not been demonstrated nor used commercially for any amine treatment systems at currently operating LNG facilities, and no LNG plant permitted recently has been required to install CCS as a part of a PSD BACT determinations. For GHG BACT, PALNG selected the use of design efficiency and operational efficiency. Operational energy efficiency includes the continuous monitoring of firebox temperature and oxygen concentration to ensure a 99.9 % DRE of methane while optimizing fuel consumption, and maintaining a combustion chamber temperature above 1400 degrees F.
The amine treatment system removes CO_2 from the incoming pipeline natural gas which is routed to the thermal oxidizers. PALNG is limited to an annual CO_2e emission limit for the thermal oxidizers and they are required to measure and calculate CO_2 emissions to demonstrate compliance with the emission rate limits.

Ground Flares and Marine Flares

PALNG will utilize good combustion practices and compliance with 40 CFR 60.18 as BACT for NO_x, CO, PM/PM_{10}/$PM_{2.5}$ and SO_2. The flares will be designed to achieve 99 percent destruction of molecules with three or less carbon atoms and 98 percent destruction of molecules with more than three carbon atoms. The permit also minimizes emissions by containing limitations on the volume of vent gas that can be sent to the flares, which represents several operational and MSS scenarios. BACT for each pollutant during flaring includes a numerical limit in the MAERT. In the case of the ground flare, PALANG may propose an Alternative Method of Control (AMOC), if required by a regulatory agency. If this occurs, the AMOC will be incorporated into the air permit. A review of the RBLC database and recently issued permits for flares identified good combustion practices and compliance with 40 CFR 60.18 as the only applicable control technology utilized to minimize emissions from flares. No add-on control technologies identified for flares, since flares are themselves control devices used to control combustible waste gas streams.

PALNG identified and evaluated flare gas recovery and good flare design and operating practices as GHG control options for the two flares. PALNG eliminated flare gas recovery as not being a technically feasible control option for this site, given the sporadic nature of emissions controlled by the flares. PALNG selected good flare design as the most effective control option for controlling methane emissions from the flares. The flares will achieve 99% DRE for methane. The addition of post combustion control on the GPP flares is generally not practicable, since the flares themselves are control devices designed to control VOC and methane (CH_4) from venting. The control of CH_4 by the flares results in the creation of additional CO_2 through combustion; however, given the relative global warming potential of CO_2 to CH_4, combustion of CH_4 is an appropriate control.

Diesel-Fired Emergency Generators/Firewater Pump Engines -

The diesel-fired emergency generators at the site are each limited to 24 hours per year of non-emergency operations. Diesel-fired firewater pump engines are limited to 39 hours of non-emergency use per year. The diesel-fired engines will be new equipment which must comply with the federal Standards of Performance for New Stationary Sources (NSPS), Subpart IIII. Compliance with the NSPS Subpart IIII represents BACT for NO_x, CO, and $PM/PM_{10}/PM_{2.5}$. BACT for SO_2 for the diesel-fired engines is the use of ultra-low sulfur diesel containing no more than 15 parts per million by weight sulfur. Each engine will be equipped with a non-resettable runtime meter. BACT for GHG will be achieved by the efficient operation of the engines and limited hours of operation. Additional controls for the engines would not be economically reasonable, given the very low hours of operation allowed.

Fuel Pre-Heaters

PALNG will operate two 3.8 MMBtu/hr natural gas-fired fuel gas pre-heaters. PALNG will use low NO_x burners as BACT to meet an emission limit of 0.049 lb/MMBtu. BACT for CO is 0.049 lb/MMBtu. BACT for NO_x, VOC, CO and GHG is also the use of good combustion practices. BACT for $PM/PM_{10}/PM_{2.5}$ and SO_2 is the use of low sulfur gaseous fuel. PALNG proposes the use of low carbon fuels, design energy efficiency measures, and operational energy efficiency measures as BACT for GHG emissions. Other potential controls were not selected due to technical infeasibility or economic infeasibility, since the pre-heaters are very small emission sources. A review of the RBLC data base confirms that the controls proposed for the small gas-fired fuel gas pre-heaters by PALNG are consistent with recent BACT decisions for small combustion sources and satisfies BACT.

Storage Tanks

Due to the low vapor pressure of diesel and amine makeup solution (less than 0.5 psia), and due to the relatively small size of the tanks, BACT for all tanks that will store diesel or amine makeup solution is a fixed-roof tank with submerged fill. These tanks will be painted white or aluminum, except those provided to service fire water pumps, which will be painted red. The two-condensate storage tank will be equipped with a closed vent system that captures and collects VOC vapors and routes them to the ground flare, achieving a 98% DRE. The RBLC shows no additional control for storage of low volatility organic liquids containing low levels of hydrocarbons. PALNG's proposed BACT for VOC for storage tanks storing these substances is consistent with recent BACT decisions and satisfies BACT.

Condensate Truck Loading

Condensate truck loading emissions will also be captured and routed to the ground flare. Capture efficiency will be 98.7% in accordance with NSPS XX. This represents BACT for condensate truck loading.

Equipment Leak Fugitives

PALNG will implement the TCEQ's 28VHP LDAR program to control VOC and methane (GHG) emissions from equipment fugitive leaks as BACT. Accessible valves will be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer that conforms to requirements of 40 CFR 60, Appendix A, Method 21. Leaking valves or components found to be emitting 500 parts per million by volume or found by visual inspection to be leaking will be tagged and replaced or repaired.

Circuit Breakers

As BACT, PALNG will use state of the art circuit breakers that are designed to meet the American National Standards Institute C37.013 standard for high-voltage circuit breakers, which must achieve a SF_6 leak rate of 0.05% by weight or less annually. PALNG will also equip the circuit breakers with a leak detection monitor and alarm. No other controls are feasible or economically reasonable for GHG emissions from the circuit breakers.

VII. Air Quality Analysis

PALNG's air quality analysis (AQA) utilized air dispersion modeling and existing ambient monitoring data to demonstrated that the proposed project's emissions will not adversely affect public health and welfare, which includes the National Ambient Air Quality Standards (NAAQS), PSD increment, additional impacts, minor new source review of regulated pollutants without a NAAQS, and air toxics review. The AQA was audited by the TCEQ's Air Dispersion Modeling Team (ADMT). The AQA, as supplemented by the ADMT, is acceptable for all review types and pollutants. The results are summarized below.

A. De Minimis Analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results indicate that 1-hr NO_2 and 24-hr $PM_{2.5}$ exceed the respective de minimis concentrations and require a full impacts analysis. The De Minimis analysis modeling results for SO_2, PM_{10}, annual $PM_{2.5}$, annual NO_2, and CO indicate that the project is below the respective de minimis concentrations and no further analysis is required.

The justification for selecting the EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels is based on the assumptions underlying EPA's development of the 1-hr NO_2 and 1-hr SO_2 De Minimis levels. As explained in EPA guidance memoranda[1,2], the EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 1-hr NO_2 and 1-hr SO_2 NAAQS.

The $PM_{2.5}$ De Minimis levels are the EPA recommended De Minimis levels. The use of the EPA recommended De Minimis levels is sufficient to conclude that a proposed source will not cause or contribute to a violation of a $PM_{2.5}$ NAAQS or $PM_{2.5}$ PSD increments based on the analyses documented in EPA guidance and policy memoranda[3].

While the De Minimis levels for both the NAAQS and increment are identical for $PM_{2.5}$ in the table below, the procedures to determine significance (that is, predicted concentrations to compare to the De Minimis levels) are different. This difference occurs because the NAAQS for $PM_{2.5}$ are statistically based, but the corresponding increments are exceedance-based.

Table 1. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter ($\mu g/m^3$)

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	De Minimis ($\mu g/m^3$)
SO_2	1-hr	5.2	7.8
SO_2	3-hr	5	25
SO_2	24-hr	2	5
SO_2	Annual	0.05	1
PM_{10}	24-hr	2	5
PM_{10}	Annual	0.2	1
$PM_{2.5}$ (NAAQS)	24-hr	1.3	1.2

[1] www.epa.gov/sites/production/files/2015-07/documents/appwso2.pdf
[2] www.tceq.texas.gov/assets/public/permitting/air/memos/guidance_1hr_no2naaqs.pdf
[3] www.tceq.texas.gov/permitting/air/modeling/epa-mod-guidance.html

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
$PM_{2.5}$ (NAAQS)	Annual	0.16	0.2
$PM_{2.5}$ (Increment)	24-hr	2	1.2
$PM_{2.5}$ (Increment)	Annual	0.19	0.2
NO_2	1-hr	16	7.5
NO_2	Annual	0.96	1
CO	1-hr	1874	2000
CO	8-hr	186	500

The 1-hr SO_2, 24-hr and annual $PM_{2.5}$ (NAAQS), and 1-hr NO_2 GLCmax are based on the highest five-year averages of the maximum predicted concentrations determined for each receptor.

The GLCmax for all other pollutants and averaging times represent the maximum predicted concentrations over five years of meteorological data.

Intermittent guidance was relied on for the 1-hr SO_2 and 1-hr NO_2 PSD De Minimis analyses.

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA' s Guideline on Air Quality Models (GAQM). Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind the MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the 1000 tpy NO_x and 500 tpy SO_2 Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.2 µg/m^3 and 0.009 µg/m^3, respectively. Since the combined direct and secondary 24-hr $PM_{2.5}$ impacts are above the De minimis level, a full impacts analysis is required. Since the combined direct and secondary annual $PM_{2.5}$ impacts are below the De minimis level, no additional analysis is required.

The applicant reviewed ozone photochemical modeling conducted for a nearby site. More information regarding the photochemical modeling can be found below in the NAAQS Analysis section.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that 24-hr SO_2, 24-hr PM_{10}, annual NO_2, and 8-hr CO are below their respective monitoring significance level.

Table 2. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (µg/m^3)	Significance (µg/m^3)
SO_2	24-hr	2	13
PM_{10}	24-hr	2	10
NO_2	Annual	0.96	14
CO	8-hr	186	575

The GLCmax represent the maximum predicted concentrations over five years of meteorological data.

The applicant evaluated ambient $PM_{2.5}$ and ozone monitoring data to satisfy the requirements for the pre-application analysis.

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 482450021 located at 2200 Jefferson Dr., Port Arthur, Jefferson County. The applicant used a three-year average (2016-2018) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value (22 µg/m^3). The three-year average (2016-2018) of the annual concentrations was used for the annual value (9 µg/m^3) .The use of this monitor for $PM_{2.5}$ is reasonable based on this monitor being the closest $PM_{2.5}$ monitor to the site (approximately 16 kilometers [km] to the northeast), a quantitative analysis of source emissions located within 10 km of the project site and monitor location, and the monitor is located in an area surrounded by industry that is similar to the project site. The background concentrations were also used in the NAAQS analysis.

Background concentrations for ozone were obtained from the EPA AIRS monitor 482450101 located at 5200 Mechanic St., Sabine Pass, Jefferson County. A three-year average (2016-2018) of the annual fourth highest daily maximum 8-hr concentrations (68 ppb) was used in the analysis. The use of this monitor for ozone is reasonable based on this monitor being the closest ozone monitor to the site (approximately 8 km to the southeast) and the monitor is located in an area surrounded by industry that is similar to the project site

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 24-hr $PM_{2.5}$ and 1-hr NO_2 exceed the respective de minimis concentration and require a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 3. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Conc. = [Background + GLCmax] ($\mu g/m^3$)	Standard ($\mu g/m^3$)
$PM_{2.5}$	24-hr	5	22	27	35
NO_2	1-hr	175	Note background discussion below	175	188

The 24-hr $PM_{2.5}$ GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted 24-hr concentrations determined for each receptor.

The 1-hr NO_2 GLCmax is the highest five-year average of the 98th percentile of the annual distribution of predicted daily maximum 1-hr concentrations determined for each receptor.

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 482450628 located at 6956 James Gamble Dr., Port Arthur, Jefferson County. For the 1-hr NO_2 NAAQS analysis, the applicant conducted their evaluation by combining NO_2 background concentrations with the predicted concentrations on an hourly basis for each modeled receptor. The applicant followed EPA guidance when developing hourly background concentrations. The applicant determined the three-year average (2016-2018) of the 98th percentile of the annual distribution of the 1-hr concentrations for each hour of the day. These background values were then used in the model (as hourly background scalars) to be combined with model predictions giving a total predicted concentration. The use of this monitor is reasonable based on this monitor being near the project site (approximately 9.5 km to the north), the quantitative analysis of source emissions located within 10 km of the project site and monitor location, and the monitor is located in an area surrounded by greater amount of industry than the project site.

As stated above, to evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA' s GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind the MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the 1000 tpy NO_x and 500 tpy SO_2 Harris County source, the applicant estimated a 24-hr secondary $PM_{2.5}$ concentration of 0.2 $\mu g/m^3$. When this estimate is added to the GLCmax listed in Table 3 above, the results are less than the NAAQS. The applicant did not include some recently permitted sources as noted in the protocol review (permit # 6056 and 8404); the ADMT utilized secondary $PM_{2.5}$ formation results from previous modeling memos and found the results would not be affected.

To evaluate proposed emissions for the ozone analysis, the applicant reviewed photochemical modeling for a nearby project (Cheniere Sabine Pass). The nearby project that conducted photochemical modeling is located a few kilometers away from this project site and was conducted for the same type of facilities (i.e. a liquefaction facility that liquefies natural gas for export from an existing terminal). However, the applicant noted that the photochemical modeling project had approximately five times the amount of NO_x emissions than what is proposed for this project. The photochemical modeling technical report notes that the predicted impacts at monitors in the BPA area ranged from 0.1-0.5 parts per billion (ppb) for the allowable case, which represents the base case plus the nearby project's allowable emissions. Finally, the applicant concluded that their proposed project would be insignificant for ozone based on the current air quality trends and the photochemical modeling that demonstrates that the same type of facility, with approximately five times as much NO_x, is insignificant. The photochemical modeling results added together with the representative monitoring data is less than the 8-hr ozone NAAQS.

The applicant also addressed a recent source of emissions not included in previous photochemical modeling (Golden Pass project - Permit Numbers 116055 and PSDTX1386). The proposed Port Arthur LNG facility, the Cheniere Sabine Pass facility, and the Golden Pass facility are all in close proximity to each other and have similar source types. In addition, the Port Arthur LNG facility and Golden Pass facility have a smaller quantity of NO_x emissions than the Cheniere Sabine Pass facility. Although the combined VOC emissions from the Port Arthur LNG facility and Golden Pass facility are greater than the VOC emissions from the Cheniere Sabine Pass facility, the BPA area is NO_x-limited and ozone formation is more dependent on NO_x emissions. Therefore, due to the proximity of the facilities, common source types, and quantity of emissions at each site, it is reasonable to use the photochemical modeling from the Cheniere Sabine Pass facility.

D. Increment Analysis

The De Minimis analysis modeling results indicate that 24-hr $PM_{2.5}$ exceeds the respective de minimis concentration and requires a PSD increment analysis.

Table 4. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (μg/m^3)	Increment (μg/m^3)
$PM_{2.5}$	24-hr	8.8	9

The GLCmax for the 24-hr $PM_{2.5}$ is the maximum high, second high (H2H) predicted concentration across five years of meteorological data.

The GLCmax for 24-hr $PM_{2.5}$ reported in the table above represents the total predicted concentration associated with modeling the direct $PM_{2.5}$ emissions and the contributions associated with secondary $PM_{2.5}$ formation (discussed above in the NAAQS Analysis section).

E. Additional Impacts Analysis

The applicant performed an Additional Impacts Analysis as part of the PSD AQA. The applicant conducted a growth analysis and determined that population will not significantly increase as a result of the proposed project. The applicant conducted a soils and vegetation analysis and determined that all evaluated criteria pollutant concentrations are below their respective secondary NAAQS. The applicant meets the Class II visibility analysis requirement by complying with the opacity requirements of 30 TAC Chapter 111. The Additional Impacts Analyses are reasonable and possible adverse impacts from this project are not expected.

The ADMT evaluated predicted concentrations from the proposed project to determine if emissions could adversely affect a Class I area. The nearest Class I area, Breton Wilderness, is located approximately 470 kilometers (km) from the proposed site.

The H_2SO_4 24-hr maximum predicted concentration of 0.3 µg/m^3 occurred approximately 608 meters from the property line towards the southwest. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 10.5 km from the proposed sources, in the direction of the Breton Wilderness Class I area is 0.05 µg/m^3. The Breton Wilderness Class I area is an additional 459.5 km from the edge of the receptor grid. Therefore, emissions of H_2SO_4 from the proposed project are not expected to adversely affect the Breton Wilderness Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than de minimis levels at a distance of 23 km from the proposed sources in the direction the Breton Wilderness Class I area. The Breton Wilderness Class I area is an additional 447 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Breton Wilderness Class I area.

F. Minor Source NSR and Air Toxics Review

Table 5. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	8	817
H_2SO_4	1-hr	1	50
H_2SO_4	24-hr	0.3	15
H_2S	1-hr	0.0003	108

Table 6. Minor NSR Site-wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	GLCmax Location	ESL ($\mu g/m^3$)
Ethylene	74-85-1	1-hr	355	Western Property Line	1400
Ethylene	74-85-1	Annual	7	Western Property Line	34
Ammonia	7664-41-7	1-hr	6	155m South	180
Diesel Fuel	68334-30-5	1-hr	1487	Western Property Line	1000
Diesel Fuel	68334-30-5	Annual	11	Eastern Property Line	100
Formaldehyde	50-00-0	1-hr	0.4	1166m North	15

The applicant did not address site-wide diesel fuel for the annual averaging time analysis. However, the ADMT performed a test run based on the 1-hr diesel fuel modeling submitted by the applicant and supplemented this information in Table 6 above.

Table 7. Minor NSR Hours of Exceedance for Health Effects

Pollutant	Averaging Time	1 X ESL GLCmax
Diesel Fuel	1-hr	3

The GLCmax locations are listed in Table 7 above. The locations are listed by their approximate distance and direction from the property line of the project site.
The applicant considered the GLCmax as the GLCni.

G. Greenhouse Gases

EPA has stated that unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs, including no PSD increment. The global climate-change inducing effects of GHG emissions, according to the “Endangerment and Cause or Contribute Finding”, are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [EPA’s PSD and Title V Permitting Guidance for GHGs at 48]. Thus, EPA has concluded in other GHG PSD permitting actions it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit.

The TCEQ has determined that an air quality analysis would provide no meaningful data and has not required the applicant to perform one. As stated in the preamble to TCEQ's adoption of the GHG PSD program, the impacts review for individual air contaminants will continue to be addressed, as applicable, in the state's traditional minor and major NSR permits program per 30 TAC Chapter 116.

VIII. Conclusion

PALNG has demonstrated that this project meets all applicable rules, regulations and requirements of the Texas and Federal Clean Air Acts. The proposed facilities and controls represent BACT. The modeling analysis indicates that the proposed project will not violate the NAAQS, cause an exceedance of the increment, or have any adverse impacts on soils, vegetation, or Class I Areas. Sitewide modeling for health effects identified three instances of the concentration of diesel fuel exceeding the effective screening level (ESL) for the modeled meteorological year. Subsequent review by TCEQ toxicology division found that due to the conservative nature of the ESL, the relatively small exceedance amount and the location of the exceedance at the facility property line, no short- or long-term adverse health effects are anticipated. Therefore, the modeling predicted non-criteria pollutants were not expected to cause adverse health effects.

The Executive Director of the TCEQ proposes a preliminary determination of issuance of this permit for PALNG to construct and operate the natural gas liquefaction plant and export terminal as proposed.