TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

November 24, 2025

Laurie Gharis, Chief Clerk
Texas Commission on Environmental Quality
P.O. Box 13087, MC 105
Austin, Texas 78711-3087

Re: Backup Material for Executive Director's Response to Hearing Requests for
Freeport LNG Development LP
Air Quality Permit No. 104840 and N170M1
Docket No. 2025-1682-AIR

Dear Ms. Gharis:

Enclosed please find a copy of the following documents for inclusion in the background material for this permit application:

- The final draft permit, including any special conditions or provisions, for permit number 104840 and N170M1
- Maximum Allowable Emission Rate Table (MAERT)
- The summary of the technical review of the permit application
- The compliance summary of the applicant
- Air Quality Analysis Modeling Audit
- Second Modeling Audit
- Preliminary Determination Summary.

If you have any questions, please do not hesitate to call me at extension 5933 or email me at Katelyn.Ding@tceq.texas.gov.

Sincerely,

Katelyn Ding, Staff Attorney
Environmental Law Division

Enclosures

Special Conditions

Permit Numbers 104840 and N170M1

1. This permit covers only those sources of emissions listed in the attached table entitled "Emission Sources - Maximum Allowable Emission Rates" (MAERT), and those sources are limited to the emission limits on that table and other operating conditions specified in this permit. Also, this permit authorizes the emissions from planned maintenance, startup, and shutdown. **(TBD)**

2. Non-fugitive emissions from relief valves, safety valves, or rupture discs of gases containing volatile organic compounds (VOC) at a concentration of greater than 1 percent are not authorized by this permit unless authorized on the MAERT. Any releases directly to atmosphere from relief valves, safety valves, or rupture discs of gases containing VOC at a concentration greater than 1 weight percent are not consistent with good practice for minimizing emissions. **(TBD)**

Federal Applicability

3. These facilities shall comply with applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on Standards of Performance for New Stationary Sources, Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60): **(06/19)**

   A. Subpart A: General Provisions.

   B. Subpart Db: Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

   C. Subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

   D. Subpart KKKK: Standards of Performance for Stationary Combustion Turbines.

4. 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: National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

Flare

5. The EPN: PTFFLARE shall be designed and operated in accordance with the following requirements: **(TBD)**

   A. The flare (EPN PTFFLARE) will be pressure-assisted.

   B. The flare shall be operated with a flame present at all times when in use. 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. If operating with dual, redundant pilot flames, the loss of one of the pilot flames is not considered a loss of pilot flame to the flare system. Each pilot flame monitoring device shall be accurate to within manufacturer's specifications, and shall be calibrated at a frequency in accordance with the manufacturer's specifications. **(4/18)**

C. 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 as determined and documented using 40 CFR Part 60, Appendix A, Test Method 22 or equivalent method. **(4/18)**

D. 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 (uncertainty) specifications: the flow monitor shall be +/- 5.0%, temperature sensor shall be +/- 2.0% at absolute temperature, and pressure sensor shall be +/- 5.0 mmHg.

E. The flow monitor shall operate at least 95% of the time when the flare is operational, averaged over a rolling twelve (12) month period. The permit holder shall install composition analyzer or calorimeter that meets the requirements in AMOC-71 and follows the QA/QC procedures in AMOC-71.

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

F. Planned maintenance, startup, and shutdown vent gas releases to the flare shall be limited to no more than 71.6 MMscf/yr based on a rolling 12-month total.

G. The requirements of this condition are not applicable during emission events. Emission events are not authorized by this permit.

H. Operations of the flare are subject to the requirements of the Alternate Means of Control Plan (AMOC-71). Where applicable the requirements of AMOC-71 shall supersede the requirements of this Special Condition.

Fuel Gas

6. Combustion units are subject to the following requirements for fuel sulfur: **(TBD)**

A. Fuel for the flare pilots is limited to boil-off gas, pipeline quality natural gas, or a blend of these fuels.

B. Fuel gas streams specified in paragraph A shall have a total sulfur content not to exceed 2 grains per 100 dscf on a rolling 12-month average.

C. Compliance with the requirements of paragraph B of this Special Condition shall be verified through sampling of fuel gas at least semi-annually. Fuel gas streams identified in paragraph A may be sampled individually, or a representative sample of blended fuel gas may be taken from the fuel gas header.

For natural gas, tariff sheets documenting the sulfur content of the fuel may be retained in lieu of performing sampling.

Emergency Engines

7. The emergency engines authorized in this permit Emission Point Numbers (EPNs): PTFFWP and PTFFWP2, PTFEAC-1 and PTFEAC-2, and PTFEG-1 through PTFEG-6 may only be fired with diesel fuel containing no more than 15 parts per million (ppm) sulfur by weight. **(4/18)**

   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.

8. The following requirements apply to the emergency generators (EPNs PTFEG-1 through PTFEG-6) and the emergency firewater pumps (EPNs PTFFWP and PTFFWP2, PTFEAC-1 and PTFEAC-2, and PTFEG-1): **(TBD)**

   A. Each emergency firewater pump (EPNs PTFFWP and PTFFWP2) shall be limited to 100 hours per year of maintenance checks, readiness testing, and non-emergency operation, as defined at 40 CFR § 63.6640(f).

   B. Each emergency generator (EPNs PTFEAC-1 and PTFEAC-2, and PTFEG-1 through PTFEG-6) shall be limited to 50 hours per year of non-emergency operation, as defined at 40 CFR § 63.6640(f).

   C. Each engine shall be equipped with a non-resettable hour meter.

   D. Emergency generators (EPNs PTFEG-4 through PTFEG-5 and PTFEAC-1 through PTFEAC-2) shall satisfy the Tier 4 exhaust emission standards specified at 40 CFR Part 1039.102.

   E. Firewater pumps (EPNs PTFFWP and PTFFWP2) shall satisfy the Tier 3 exhaust emission standards specified at Appendix I to 40 CFR Part 1039.

   F. Emergency generators (EPNs PTFEG-1 through PTFEG-3 and PTFEG-6) shall satisfy the Tier 2 exhaust emission standards specified at Appendix I to 40 CFR Part 1039.

   G. Compliance with the emission limits of paragraph E and F of this Special Condition shall be demonstrated by retaining a copy of the manufacturers' certificate of conformity.

9. Opacity of emissions from the turbine, heating medium heaters, and thermal oxidizers shall not exceed five percent averaged over a six-minute period from each stack.

   A. 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.

   B. 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.

   C. Observations shall be performed and recorded quarterly. 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.

Combustion Turbine

10. Emissions Standards and Operating Specifications for Combustion Turbine (EPN: CT).

A. The concentration of nitrogen oxides (NO_x) in the exhaust gas shall not exceed 2.0 parts per million by volume dry (ppmvd) corrected to 15 percent oxygen (O_2), on a rolling 3-hour average, subject to the following specifications:

(1) Hours of startup and shutdown are excluded.

(2) Excess emissions caused by emission events are excluded.

(3) Excess emissions during initial or other major dry low NO_x burner tuning sessions are excluded. 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.

B. The concentration of carbon monoxide (CO) from EPN: CT shall not exceed 4.0 ppmvd corrected to 15 percent O_2, on a rolling 3-hour average, excluding startup and shutdown.

C. The concentration of ammonia (NH_3) from EPN: CT shall not exceed 10 ppmvd corrected to 15 percent O_2, on a rolling 24-hour average.

D. Planned startup or shutdown is limited to two hours per planned startup or shutdown event.

Heaters

11. The heaters are subject to the following requirements **(TBD)**

A. For EPNs: 65B-81A through 65B-81E.

(1) Each heater is limited to firing no more than 132 MMBtu/hr based on the HHV of the fuel. All five heaters totaled (EPNs: 65B-81A through 65B-81E) are limited to firing 1,511,136 MMBtu per rolling 12-month period.

(2) The concentration of NO_x from the exhaust gas of each stack shall not exceed 5.0 ppmvd corrected to 3 percent O_2, on a one-hour average.

(3) The concentration of CO from the exhaust gas of each stack shall not exceed 25 ppmvd corrected to 3 percent O_2, on a one-hour average. This is to be demonstrated during initial compliance testing.

B. For EPNs: 69B-81A through 69B-81C.

(1) Each heater is limited to firing no more than 132 million British thermal units per hour (132 MMBtu/hr) based on the higher heating value (HHV) of the fuel. All three heaters totaled (EPNs: 69B-81A through 69B-81C) are limited to firing 2,312,640 MMBtu per rolling 12-month period.

(2) The concentration of NO_x from the exhaust gas of each stack shall not exceed 2.0 ppmvd corrected to 3 percent O_2, on a one-hour average.

(3) The concentration of CO from the exhaust gas of each stack shall not exceed 5.0 ppmvd corrected to 3 percent O_2, on a one-hour average. This is to be demonstrated during initial compliance testing.

(4) The concentration of ammonia (NH_3) from EPNs 69B-81A through 81C shall not exceed 10 parts per million by volume dry (ppmvd) corrected to 3 percent oxygen (O2), on a rolling 24-hour average and an annual average. This concentration limit shall not apply to MSS activities, during which emissions are limited by the emission rates shown on the MAERT.

C. Heaters at this site are exempt from NO_x and CO operating requirements identified in the special conditions during planned startup and shutdown if the following criteria are satisfied.

(1) The maximum allowable emission rates in the permit authorizing the facility are not exceeded.

(2) The startup period does not exceed 8 hours in duration and the firing rate does not exceed 75 percent of the design firing rate. The time it takes to complete the shutdown does not exceed 4 hours.

(3) Control devices are started and operating properly when venting a waste gas stream.

Ammonia Handling

12. 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.

13. The permit holder shall maintain the piping and valves in NH_3 service as follows:

A. All operating practices and procedures relating to the handling and storage of NH_3 shall conform to the safety recommendations specified for that compound by guidelines of the American National Standards Institute and the Compressed Gas Association.

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

C. Immediately, but no later than 24 hours following the detection of a leak, plant personnel shall take one or more of the following actions: (**4/18)**

(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.

Fugitives

Piping, Valves, Pumps, Agitators, and Compressors - Intensive Directed Maintenance – 28LAER

14. 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:

- piping and instrumentation diagram (PID);
- a written or electronic database or electronic file;
- color coding;
- a form of weatherproof identification; or
- 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 paragraph 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. In addition, all connectors shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer with a directed maintenance program in accordance with items F thru J of this special condition.

In lieu of the monitoring frequency specified above, connectors may be monitored on a semiannual basis if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Connectors may be monitored on an annual basis if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

The percent of connectors leaking shall be determined using the following formula:

$$\frac{C_l + C_s}{C_t} \times 100 = C_p$$

Where:

C_l = the number of connectors found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

C_s = the number of connectors for which repair has been delayed and are listed on the facility shutdown log.

C_t = the total number of connectors in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including non-accessible and unsafe-to-monitor connectors.

C_p = the percentage of leaking connectors for the monitoring period.

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 by the end of the 72 hours 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 with a directed maintenance program. Non accessible valves shall be monitored by leak-checking for fugitive emissions at least annually using an approved gas analyzer with a directed maintenance program. 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. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown. 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.

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, than 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.

A directed maintenance program shall consist of the repair and maintenance of components assisted simultaneously by the use of an approved gas analyzer such that a minimum concentration of leaking VOC is obtained for each component being maintained. Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. All new and replacement pumps, compressors, and agitators shall be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. These seal systems need not be monitored and 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.

All other pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly.

H. Damaged or leaking valves, connectors, compressor seals, pump seals, and agitator seals found to be emitting VOC in excess of 500 parts per million by volume (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. Records of the first attempt to repair shall be maintained. 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. 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.

I. 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, 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.

J. 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.

K. In lieu of the monitoring frequency specified in paragraph F, valves in gas and light liquid service may be monitored on a semiannual basis if the percent of valves leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Valves in gas and light liquid service may be monitored on an annual basis if the percent of valves leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of valves leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

L. The percent of valves leaking used in paragraph K shall be determined using the following formula:

$$\frac{(V_l + V_s)}{V_t} \times 100 = V_p$$

Where:

V_l = the number of valves found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

V_s = the number of valves for which repair has been delayed and are listed on the facility shutdown log.

V_t = the total number of valves in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including non-accessible and unsafe to-monitor valves.

V_p = the percentage of leaking valves for the monitoring period.

M. Any component found to be leaking by physical inspection (i.e., sight, sound, or smell) shall be repaired or monitored with an approved gas analyzer within 15 days to determine whether the component is leaking in excess of 500 ppmv of VOC. If the component is found to be leaking in excess of 500 ppmv of VOC, it shall be subject to the repair and replacement requirements contained in this special condition.

15. The alternative screening procedure ("soap bubble test") as specified in 40 CFR 60, Appendix A-7, Method 21, Section 8.3.3 may be used for the purpose of verifying that the components are not leaking in lieu of the procedure specified in Special Condition No. 14.E, 14.F, or 14.G, or 14.H. **(06/20)**

16. All accessible connectors in gas/vapor and light liquid service shall be monitored quarterly with an approved gas analyzer in accordance with Items E, F, and H of Special Condition No. 14 that are applicable to monitoring of connectors. **(02/18)**

A. Connectors may be monitored on a semiannual basis if the percent of connectors leaking for two consecutive quarterly monitoring periods is less than 0.5 percent.

Connectors may be monitored on an annual basis if the percent of connectors leaking for two consecutive semiannual monitoring periods is less than 0.5 percent.

If the percent of connectors leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

B. The percent of connectors leaking used in paragraph A shall be determined using the following formula:

$$(C_l + C_s) \times 100/C_t = C_p$$

Where:

C_l = the number of connectors found leaking by the end of the monitoring period, either by Method 21 or sight, sound, and smell.

C_s = the number of connectors for which repair has been delayed and are listed on the facility shutdown log.

C_t = the total number of connectors in the facility subject to the monitoring requirements, as of the last day of the monitoring period, not including non-accessible and unsafe-to-monitor connectors.

C_p = the percentage of leaking connectors for the monitoring period.

Optical Gas Imaging

17. The following modifications to the fugitive monitoring program specified in these Special Conditions may be implemented. These modifications are specified in order for the permit holder to be allowed to implement an alternate work practice (AWP) as an alternative to the current Method 21 monitoring requirements specified in Special Condition Nos. 14 and 16. Prior to implementing this AWP, the permit holder shall notify the Houston Regional Office of their intent to use the alternative work practice in writing as described in 30 TAC §115.358 (g). **(08/19)**

A. In lieu of the Method 21 monitoring requirements of Special Condition Nos. 14 and 16, the permit holder may monitor components on a bi-monthly basis using an optical gas imaging camera (OGIC) meeting the requirements of 40 Code of Federal Regulations (CFR) §60.18(i)(1) as described in Attachment A of this permit. Components that would be considered inaccessible (e.g., insulated components), difficult-to-monitor (DTM), or unsafe-to-monitor (UTM) when using a Method 21 instrument will be monitored with the OGIC so long as such components are not considered DTM or UTM, as defined in Paragraph G of this condition, when using an OGIC.

B. All components described above must also be monitored annually using an approved gas analyzer conforming to the requirements listed in Method 21 of 40 CFR part 60, appendix A. Subsequent annual monitoring must be conducted every 12 months from the initial annual monitoring period. As an option, a facility may choose to space out the Method 21 monitoring of all components over a 12-month period, as long as all components are monitored on a set schedule every 12 months. Method 21 monitoring for components that are added to an area may be completed during the next scheduled annual Method 21 monitoring event for that area provided that the components are monitored within 12 months of being placed in service. This requirement does not apply to components that would be considered DTM or UTM when using a Method 21 instrument. **(06/20)**

C. All OGIC operators shall meet the minimum training requirements in 30 Texas Administrative Code (TAC) §115.358(h) as specified in subparagraph 2.1.5 of Attachment A of this permit.

D. An OGIC daily verification check shall be performed prior to a monitoring survey as specified in 40 CFR 60.18 (i) (2) (i) through (iv). The daily OGIC verification check shall be conducted by each separate OGIC operator that will be performing imaging using the same OGIC for that day.

E. Bi-monthly monitoring using the OGIC will be performed following the procedures outlined in paragraph 2 and subparagraphs 2.1.1 through 2.1.6 of Attachment A of this permit.

F. When monitoring using the OGIC, components within the OGIC field of view will be observed for a minimum of three seconds. All emissions imaged by the optical gas imaging instrument are considered to be leaks and are subject to repair. All emissions visible to the naked eye are also considered to be leaks and are subject to repair.

G. When a leak is identified with the OGIC, an approved gas analyzer conforming to the requirements listed in Method 21 of 40 CFR part 60, appendix A will be used to monitor and record the concentration of the leak before repair. Repaired components will be remonitored to verify the success of the repair using an OGIC, an approved gas analyzer, or the soap bubble test described in Section 8.3.3 of Method 21. Scenarios where a leak is detected by the OGIC but a Method 21 approved gas analyzer reading is not required include: components that are considered DTM or UTM with a Method 21 instrument, and components that are insulated and therefore not accessible for Method 21 instrument monitoring. A difficult-to-monitor component is a component that cannot be inspected without elevating the monitoring personnel more than two meters above a permanent support surface or that requires a permit for confined space entry as defined in 29 CFR §1910.146. An unsafe-to-monitor component is a component that the owner or operator determines is unsafe to monitor because monitoring personnel would be exposed to an immediate danger as a consequence of conducting the monitoring. **(06/20)**

H. The alternative monitoring schedule authorized in Subparagraph I of Special Condition No. 14 is not applicable.

I. The following records shall be kept for a period of at least 5 years and be made available to the TCEQ Executive Director or designated representative upon request:

(1) Records of the make, model, and manufacturer specifications of each OGIC used to demonstrate compliance with Subparagraph A of this condition.

(2) Records demonstrating compliance with Subparagraph C of this condition.

(3) The equipment, processes, and facilities for which the owner or operator chooses to use the alternative work practice.

(4) The detection sensitivity level selected from Table 1 to subpart A of 40 CFR 60.18 for the optical gas imaging instrument.

(5) The analysis to determine the piece of equipment in contact with the lowest mass fraction of chemicals that are detectable, as specified in paragraph (i)(2)(i)(A) of 40 CFR 60.18.

(6) The technical basis for the mass fraction of detectable chemicals used in the equation in paragraph (i)(2)(i)(B) of 40 CFR 60.18.

(7) Records of the daily OGIC verification check. Record the distance, per paragraph (i)(2)(iv)(B) of 40 CFR 60.18, and the flow meter reading, per paragraph

(i)(2)(iv)(C) of 40 CFR 60.18, at which the gas was imaged during the daily OGIC verification check. Keep a video record of the daily instrument check for each configuration of the optical gas imaging instrument used during the leak survey (for example, the daily instrument check must be conducted for each lens used). The video record must include a time and date stamp for each daily instrument check. The video record must be kept for 5 years.

(8) Records of OGIC monitoring shall indicate dates, times, component areas monitored, results of imaging and the results of Method 21 monitoring for those components found leaking with the OGIC. In addition, a video record must be used to document the leak survey results. The video record must include a time and date stamp for each monitoring event. A video record can be used to meet the recordkeeping requirements if each piece of regulated equipment selected for this work practice can be identified in the video record. The video record must be kept for 5 years.

(9) The records of the annual Method 21 screening required in subparagraph B of this condition shall identify the equipment screened, the screening value measured by Method 21, the time and date of the screening, and calibration information required in Subparagraph F of Special Condition No. 14.

(10) Records of repairs to fugitive components shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components.

(11) Records of maintenance to the OGIC, as applicable, will be maintained by the OGIC owner/operator.

Initial Determination of Compliance

18. Sampling ports and platforms shall be incorporated into the design of all exhaust stacks according to the specifications set forth in the attachment entitled “Chapter 2, Stack Sampling Facilities.” Alternate sampling facility designs may be submitted for approval by the TCEQ Regional Director.

19. 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: 69B-81A, 69B-81B, 69B-81C, TO1, TO2, TO3, and TO4 to determine initial compliance with all 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. The initial stack tests for EPNs CT, 65B-81A, 65B-81B, 65B-81C, 65B-81D, 65B-81E, TO1, TO2, and TO3 have been completed. **(4/18)**

    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, then in order to demonstrate compliance with New Source Performance Standards (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 Houston 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 EPN: CT NO_x, O_2, CO, VOC, SO_2, and NH_3. 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: 65B-81A through 65B-81E and 69B-81A through 69B-81C: NO_x, CO, VOC, and O_2. **(4/18)**

(3) For EPNs: TO1, TO2, TO3, and TO4: CO, NO_X, VOC, SO_2, total particulate matter (PM), and O_2. **(4/18)**

C. For each EPN: TO1, TO2, TO3, and TO4, a VOC destruction efficiency of at least 99% or a VOC outlet concentration of 10 ppmvd or less corrected to 3 percent oxygen on a one-hour average must be demonstrated. The minimum operating temperature shall be the average temperature at which compliance with the above was demonstrated. **(4/18)**

D. For each regenerative thermal oxidizer (EPNs: TO1, TO2, TO3, and TO4) liquid scrubber system, a SO_2 removal efficiency of 97.2% across the liquid scrubber or a SO_2 outlet concentration at the liquid scrubber outlet of 8 ppmvd or less corrected to 3 percent oxygen on a one-hour average must be demonstrated. **(TBD)**

The minimum scrubber liquid pH and flow rate established in accordance with Special Conditions No. 26 and 27 shall be the average pH and minimum liquid flow rate at which compliance with the above was demonstrated based on the results of the average of at least three test runs. **(5/15)**

E. Testing Conditions.

(1) EPN: CT shall 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: 65B-81A through 65B-81E and 69B-81A through 69B-81C shall each be tested at 80% or above of the manufacturer's stated maximum heat input capacity. **(4/18)**

(3) EPNs: TO1, TO2, TO3, and TO4 shall each be tested at least 90% of the associated amine treatment system design gas throughput. **(4/18)**

F. Sampling as required by this condition shall occur within 60 days after achieving the nominal power output at which the turbine will be operated, but no later than 180 days after initial start-up of the combustion turbine. Additional sampling may be required by TCEQ or EPA.

G. 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 Houston Regional Office.

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

Continuous Demonstration of Compliance – Combustion Turbine and Heaters

20. The permit holder shall install, calibrate, and maintain a continuous emission monitoring system (CEMS) to measure and record the in-stack concentration of for NO_x and O_2 from the heaters (EPNs 65B-81A through 81E, 69B-81A through 81C); and NO_x, CO, and O_2 from the combustion turbine (EPN: CT). Heaters are not required to have a CO CEMS installed. **(TBD)**

A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60), Appendix B. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Office of Air, Air Permits Division for requirements to be met.

B. Section 1 below applies to sources subject to the quality-assurance requirements of 40 CFR Part 60, Appendix F; section 2 applies to all other sources:

(1) The permit holder shall assure that the CEMS meets the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, Section 5.2.3 and any CEMS downtime shall be reported to the appropriate TCEQ Regional Manager, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Manager.

(2) The system shall be zeroed and spanned daily, and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B, or as specified by the TCEQ if not specified in Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days.

Each monitor shall be quality-assured at least quarterly using Cylinder Gas Audits (CGA) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, Section 5.1.2, with the following exception: a relative accuracy test audit (RATA) is not required once every four quarters when four successive quarterly CGA are conducted. An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur no closer than two months.

All CGA exceedances of +15 percent accuracy indicate that the CEMS is out of control.

C. The monitoring data shall be reduced to one hour average concentrations at least once every day, using a minimum of four equally-spaced data points from each one-hour period.

D. All monitoring data and quality-assurance data shall be maintained by the source. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

E. The appropriate TCEQ Regional Office shall be notified at least 30 days prior to any required RATA in order to provide them the opportunity to observe the testing.

F. Quality-assured (or valid) data must be generated when the heaters or combustion turbine are operating 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 heaters or combustion turbine operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded. Options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ Regional Manager.

21. The NH_3 concentration in the stack of EPNs 69B-81A through 81C and CT, 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 SCR unit is in operation except for periods of startup and shutdown. **(TBD)**

A. The holder of this permit may install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NH_3. The NH_3 concentrations shall be corrected and reported in accordance with Special Condition No. 20 above.

B. The NH_3 slip may be measured using a sorbent or stain tube device specific for NH_3 measurement in the appropriate range. The frequency of sorbent or stain tube testing shall be daily.

(1) If the sorbent or stain tube testing indicates an ammonia (NH_3) slip concentration that exceeds 10 parts per million (ppm) at any time, the permit holder shall begin NH_3 testing by either the Phenol-Nitroprusside Method, the Indophenol Method, or EPA Conditional Test Method (CTM) 27 on a quarterly basis in addition to the daily sorbent or stain tube testing.

(2) If the daily testing indicates NH_3 slip is 10 ppm or less, the Phenol Nitroprusside Indophenol CTM 27 tests may be suspended until sorbent or stain tube testing again indicate 10 ppm NH_3 slip or greater.

C. 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.

D. 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).

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

22. The permit holder shall monitor and record the average hourly fuel consumption of the turbine. The fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, fuel flow meters that meet the installation, certification, and quality assurance requirements of appendix D to part 75 of this chapter are acceptable for use under this subpart.

23. The permit holder shall monitor and record the average hourly fuel consumption of each heating medium heater. The fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions.

24. The oxygen concentration for each heating medium heater (EPNs: 65B-81A through 65B-81E and 69B-81A through 69B-81C) shall be monitored when the heater is in operation to ensure compliance with the NO_X limits of this permit. **(TBD)**

A. A minimum exhaust oxygen concentration, based on a one-hour average, shall be established using the most recent performance test data. A process oxygen monitor shall be used to ensure the oxygen content of the flue gas is within the allowable range. The monitor shall be maintained according to the manufacturer’s instructions.

Continuous Demonstration of Compliance - Thermal Oxidizers

25. Vents from each amine treatment unit must be directed to the regenerative thermal oxidizers (RTO). The RTO combustion chamber outlet temperatures for EPNs: TO1, TO2, TO3, and TO4 shall be continuously monitored when waste gas is directed to the RTO. The outlet temperature must be recorded at least four times an hour (once per quarter of the hour) when waste gas is directed to the TO and averaged hourly for compliance demonstration. The temperature monitor shall operate at least 95% of the time when the RTO is operational, averaged over a rolling twelve (12) month period. **(10/20)**

A. The minimum RTO combustion chamber outlet temperature shall be 1400 degrees Fahrenheit until a minimum operating temperature is established by the testing required in previous initial compliance testing or by Special Condition No. 20. The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall be accurate to within the greater of ± 1 percent of the temperature being measured or ± 4.5 degrees Fahrenheit. **(4/18)**

B. After a planned shutdown of any pretreatment train, the permit holder shall visually inspect packing to identify any settling or other issues that would negatively affect the RTO performance. This condition does not have to be performed more than once per year if planned shutdowns occur more frequently than once per year.

26. When waste gas is directed to the RTO, the RTO wet scrubber shall be operated at the minimum pH or higher on a 1-hour average based on the most recent performance test data. The liquid pH must be recorded at least four times an hour (once per quarter of the hour) when waste gas is directed to the RTO and averaged on an hourly basis. Each monitoring device shall be cleaned with an automatic cleaning system, or cleaned weekly using hydraulic, chemical, or mechanical cleaning. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, other written procedures that provide an adequate assurance that the device is calibrated accurately, or at least weekly, whichever is more frequent, and shall be accurate to within ± 0.5 pH units. The pH meter shall operate at least 95% of the time when the RTO is operational, averaged over a rolling twelve (12) month period.

27. When waste gas is directed to the RTO, the RTO scrubber shall be operated at the minimum liquid flow rate or higher on a 1-hour average based on the most recent performance test data. The flow rate must be recorded at least four times an hour (once per quarter of the hour) when waste gas is directed to the RTO and averaged on an hourly basis. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, other written procedures that provide an adequate assurance that the device is calibrated accurately, or at least annually, whichever is more frequent, and shall be accurate to within ± 2% of span or ± 5% of design liquid flow rate. The flow monitor shall operate at least 95% of the time when the RTO is operational, averaged over a rolling twelve (12) month period.

Electrostatic Precipitator

28. Each electrostatic precipitator (ESP) shall be operated at a minimum secondary voltage established during the most recent compliance performance test data for the associated RTO (TO1, TO2, TO3, or TO4). The secondary voltage of the ESP shall be continuously monitored and compliance is based upon a block hour and, once per day, the average daily secondary voltage recorded. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, other written procedures that provide an adequate assurance that the device is calibrated accurately, or at least annually, whichever is more frequent, and shall be accurate to within one of the following: ± 2% of reading; or ± 5% over its operating range. **(TBD)**

29. Each electrostatic precipitator (ESP) shall be operated between a minimum and maximum spark rate established during the most recent compliance test data for the associated RTO (EPNs: TO1, TO2, TO3, or TO4). The spark rate of the ESP shall be continuously monitored, and compliance shall be based upon a block hour. Once a day the hour average daily spark rate shall be calculated and recorded. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, other written procedures that provide an adequate assurance that the device is calibrated accurately, or at least annually, whichever is more frequent, and shall be accurate to within ± 5% of reading. **(TBD)**

Sulfur Content

30. In order to determine SO_2 emissions from the process, the permit holder shall analyze gas sulfur content, at least quarterly, by sampling the plant feed gas prior to the first treatment device and the CO_2-rich amine waste gas prior to the RTOs using ASTM methods D1072, D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 and perform the following: **(4/18)**

    A. Monitor total feed gas flow into the plant 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;

    B. Monitor total CO_2-rich amine waste gas flow from the amine treatment system 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;

    C. Calculate SO_2 emissions as a mass balance based on the mass of incoming sulfur using the most recent incoming plant feed gas sulfur content data and the data from paragraphs A, B, the conversion of sulfur to SO_2 in the Thermal Oxidizer, and the SO_2 wet scrubber removal efficiency; and

    D. Any additional analyses besides the above, such as measuring the sulfur content of the LNG prior to being loaded onto a ship, may be used to refine the assumption that all sulfur not removed from the incoming plant feed gas is either scrubbed out of the gas or emitted as SO_2.

Compliance Assurance Monitoring

31. The following requirements apply to capture systems for the flares (EPN PTFFLARE) and thermal oxidizers (EPNs TO1, TO2, TO3, and TO4). **(TBD)**

    A. If there is a bypass for the control device, comply with one of the following requirements:

        (1) Install a flow indicator that records and verifies zero flow at least once every fifteen minutes immediately downstream of each valve that if opened would allow a vent stream to bypass the control device and be emitted, either directly or indirectly, to the atmosphere; or

        (2) Once a month, inspect the valves, verifying the position of the valves and the condition of the car seals/lock-out tags that prevent flow out the bypass and maintain records of each inspection. If the inspection is not satisfactory, the holder of this permit shall take necessary corrective action within 24 hours; or

        (3) Install an electronic position indicator that records and verifies the open or closed position, at least once every fifteen minutes, of each valve or damper that if opened would allow a vent stream to bypass the control device and be emitted, either directly or indirectly, to the atmosphere.

Maintenance, Startup, and Shutdown

32. The permit holder shall establish, implement, and update, as appropriate, a program to maintain and repair facilities. The minimum requirements of this program must include:

A. A maintenance program developed by the permit holder for all equipment that is consistent with good air pollution control practices, or alternatively, manufacturer's specifications and recommended programs applicable to equipment performance and the effect on emissions;

B. Cleaning and routine inspection of all equipment;

C. Repair of equipment on timeframes that minimize equipment failures and maintain performance;

D. Training of personnel who implement the maintenance program; and

E. Records of conducted planned MSS activities.

33. Sections of the plant handling natural gas or natural gas liquids 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.

A. The process equipment shall be degassed using good engineering and best management practices to ensure air contaminants are removed from the system through the control device (EPN: PTFFLARE) 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.

B. Equipment that only contains material that is liquid with VOC true vapor pressure (TVP) less than 0.50 psi at the normal process temperature or 95°F may be opened to atmosphere and drained without depressuring or degassing to a control device.

C. The locations and/or identifiers where the purge gas enters the process equipment or storage vessel and the exit points for the exhaust gases shall be documented; (process flow diagrams [PFDs] or piping and instrumentation diagrams [P&IDs] may be used to demonstrate compliance with the requirement). **(4/18)**

D. If the process equipment requires purging, it will be conducted using best management and good air pollution control practices.

34. All contents from process equipment or storage tanks must be removed to the maximum extent possible 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.

Netting and Offsets

35. This Nonattainment New Source Review permit is issued/approved based on the requirement that the permit holder offset the project emission increase for facilities authorized by this permit prior to the commencement of operation, through participation in the TCEQ Emission Banking and Trading (EBT) Program in accordance with the rules in 30 TAC Chapter 101, Subchapter H. **(TBD)**

A. The permit holder shall use 58.3 tons per year (tpy) of NO_X credits to offset the 44.82 tpy project emission increase for the facilities authorized by this permit at a ratio of 1.3 to 1.0.

(1) The permit holder shall use 21.5 tpy of ECs from TCEQ credit certificate numbers 2824 and 2826 to offset the 16.53 tpy NO_X project emission increase at a ratio of 1.3 to 1.0.

(2) The permit holder shall use 36.8 tpy of Mass Emission Cap and Trade (MECT) allowances available to offset the 28.29 tpy NOx project emission increase for the MECT facilities authorized by this permit at a ratio of 1.3 to 1.0.

Identify each MECT facility using the EPN and/or FIN from the MAERT.

MECT Applicable Facility Identification Numbers (FINs):

Trains 1 – 3	
EPN	**FIN**
CT	CT
65B-81B	65B-81B
65B-81A	65B-81A
65B-81D	65B-81D
65B-81E	65B-81E
65B-81C	65B-81C

B. Prior to the start of operation of the flare gas recovery project (an emissions reduction project, the permit holder shall use 45.0 tpy of NOx credits to offset the 34.6 tpy NOx project emission increase for the facilities authorized by this permit at a ratio of 1.3 to 1.0.

C. Prior to the commencement of operation, the permit holder shall obtain approval from the TCEQ EBT Program for the credits being used and then submit a permit alteration or amendment request to the TCEQ Air Permits Division (and copy the TCEQ Regional Office) to identify approved credits by TCEQ credit certificate number.

Recordkeeping

36. The records required by these special conditions shall be maintained in either hard copy or electronic format and shall be maintained for at least five years. These records shall be made immediately available at the request of personnel from the TCEQ or any air pollution control agency with jurisdiction. **(TBD)**

Date: TBD

Attachment A

Permit Number 104840 and N170

General Optical Gas Imaging Camera Operational Procedures

Freeport LNG

1 OGIC SPECIFICATIONS

Freeport LNG will utilize a FLIR GF320 Optical Gas Imaging Camera (OGIC) for streams with predominantly high concentrations of hydrocarbons and a FLIR GF343 for streams with predominantly high concentrations of carbon dioxide, or other equivalent OGICs. The FLIR GF320 is designed to detect hydrocarbons (e.g., methane and VOCs, while the FLIR GF343 is designed to detect carbon dioxide.

Freeport LNG will maintain records of the make, model, and manufacturer specifications of each OGIC instrument used under Freeport LNG's LDAR program.

2 OGIC MONITORING PROCEDURES

OGIC monitoring will be performed by appropriately trained personnel in accordance with the procedures summarized below.

A. On a daily basis, prior to beginning each OGIC monitoring event, monitoring personnel will complete an OGIC daily verification check in accordance with Section 2.1.1 of this Plan.

B. All components subject to the LDAR program and designated for OGIC monitoring will be monitored with the OGIC unless considered difficult-to-monitor or unsafe-to-monitor.

C. The distance between the OGIC and the components being surveyed shall not exceed the maximum distance (D_{Max}) established during the OGIC daily verification check. The operator will establish an optimized D_{Max} (i.e., as large as possible) during the survey, taking into account weather conditions, thermal background, viewing angle of components, and distance to monitored components.

D. Throughout the survey, monitoring personnel will endeavor to stay within a close distance to monitored components, if possible. If, based on the judgement of monitoring personnel, the distance to the monitored component is equal to or greater than 50% of D_{Max}, monitoring personnel will use a laser range finder or equivalent device to ensure compliance with the established D_{Max}. Monitoring personnel may perform an additional OGIC daily verification check to establish a new D_{Max}, as needed.

E. All visible emissions from fugitive components identified using the OGIC are considered leaks subject to repair requirements.

F. Monitoring personnel will qualitatively assess monitoring conditions throughout the survey and will follow the procedures identified in Section 2.1.2 if adverse monitoring conditions are encountered.

G. The procedures identified in Section 2.1.3 will be followed to ensure that adequate thermal background exists when viewing each component with the OGIC.

H. The procedures identified in Section 2.1.4 will be followed if interferences are encountered during the survey.

I. Monitoring personnel will meet the qualification and experience criteria outlined in Section 2.1.5 of this Plan.

J. The OGIC will be maintained as outlined in Section 2.1.6 of this Plan.

2.1.1 OGIC Daily Verification Check

An OGIC performance check will be performed on a daily basis prior to OGIC monitoring surveys, and at other times as needed, in accordance with the following procedure.

1. Start the OGIC according to the manufacturer's instructions, ensuring that all appropriate settings conform to the manufacturer' s instructions.

2. After the OGIC start-up process is completed and the OGIC is set to the intended settings, view the image produced by the OGIC to ensure that the image is normal. If the image is abnormal, perform a lens assessment and follow a proper lens cleaning procedure, if necessary.

3. Calculate the mass flow rate to be used in the daily instrument check by the following method (see Note 1):
   a. Determine the piece of equipment in contact with the lowest mass fraction of detectable chemicals, within the distance at or below the standard detection sensitivity level.
   b. Multiply the standard detection sensitivity level by the mass fraction of chemicals from the stream to determine the mass flow rate to be used in the daily instrument check using the following equation:

$$\mathbf{E_{DIC} = (E_{SDS}) \cdot \sum(X)}$$

   Where:

   E_{DIC} = Mass flow rate for the daily instrument check (grams per hour)
   E_{SDS} = Standard detection sensitivity level from Table 1 to Subpart A, (grams per hour)
   X = Mass fraction of detectable chemical(s) seen by the optical gas imaging instrument, within the operating distance at or below the E_{SDS}.

4. Prior to the beginning of the monitoring survey, test the OGIC as follows:
   a. Record ambient temperature as measured from an onsite temperature gauge or local weather station data reported via a public feed (e.g., weather.com).
   b. Record wind speed as measured from a handheld anemometer or similar device.
   c. Install a regulator on a gas cylinder containing a gas that is visible by the OGIC (e.g., methane). The regulator flow rate and gas cylinder composition shall be selected to represent the process stream(s) to be surveyed on that day. Place the cylinder in the area where the OGIC monitoring survey will take place or where similar environmental (wind, rain, etc.) conditions exist. If the wind speed increases noticeably during the monitoring survey, repeat the OGIC daily verification check. (See Note 2).
   d. Set up the OGIC at a distance from the outlet of the cylinder regulator.
   e. Open the valve on the regulator to provide a mass flow rate that is no greater than the mass flow rate calculated in Step 3 while observing the gas flow through the OGIC.

f. Gradually increase the distance between the OGIC and the outlet of the cylinder regulator and view the emission with the OGIC at each distance interval. The maximum distance where the emission is viewed by the OGIC for a minimum duration of 10 seconds is D_{Max}. Upon establishing D_{Max}, the OGIC daily verification check is complete.

Notes:

1) The calculation described in Step 3 may be performed once for all streams at the facility based on the heat and material balance (HMB) and need not be repeated for the daily instrument check. The results of the calculation described in Step 3 will be maintained.
2) Monitoring personnel may use a single regulator/cylinder composition combination for all process streams to be monitored with the hydrocarbon OGIC as long as the combination provides a mass flow rate that is no greater than the maximum flow rate calculated in Step 3 for all process streams to be monitored.

2.1.2 OGIC Use in Adverse Conditions

2.1.2.1 Wind

Wind speed is recorded during the OGIC daily verification check. If the wind speed within the survey area(s) has a Beaufort number of five or higher, the survey will be postponed in those areas until the wind speed has decreased. A wind speed chart is presented in Table 5-1.

Table 5.1 Wind speed Chart

Beaufort number	Wind (km/h)	Wind (mph)	Wind classification	Wind effects on land	Wind effects on water
0	<1	<1	Calm	Smoke rises vertically	Water calm, mirror-like
1	1-5	1-3	Light air	Smoke drift indicates wind direction; still wind vanes	Scale-like ripples with no foam crests
2	6-11	4-7	Light breeze	Leaves rustle; wind felt on face; wind vanes moved by wind	Small wavelets; crests have a glassy appearance and do not break
3	12-19	8-12	Gentle breeze	Leaves and twigs constantly moving; light flags extended	Large wavelets; crests begin to break, scattered whitecaps
4	20-29	13-18	Moderate breeze	Dust and loose paper raised; small branches move	Small waves 1-4' becoming longer; many whitecaps
5	30-38	19-24	Fresh breeze	Small trees with leaves begin to Sway	Moderate, longer waves 4-8'; whitecaps common; some spray
6	39-50	25-31	Strong breeze	Larger tree branches moving; phone lines whistle	Larger waves 8-13 whitecaps common; more spray
7	51-61	32-38	Near gale	Whole trees moving; difficult to walk against wind	Sea heaps up; waves 13-20'; crests break; white foam streaking off breakers
8	62-74	39-46	Gale	Twigs break off trees; difficult to walk against wind	Moderately high waves, 13-20', with greater lengths; crests beginning to break into foam blown in white streaks

Beaufort number	Wind (km/h)	Wind (mph)	Wind classification	Wind effects on land	Wind effects on water
9	75-86	47-54	Strong gale	Slight damage to buildings; shingles and slates torn off roofs	High waves of 20'; rolling seas; dense streaks of foam; spray may reduce visibility
10	87-101	55-63	Storm	Trees uprooted; considerable structural damage to buildings	Very high waves, 20-30', with overhanging crests; sea white with blown foam
11	102-115	64-72	Violent storm	Widespread damage	Huge waves, 30-45', foam patches cover sea; air filled with spray; visibility reduced
12	>115	>72	Hurricane	Widespread damage	Huge waves, over 45' air filled with foam; sea all white with driving spray; little visibility

2.1.2.2 Rain

The OGIC may be used in light rain as long as the OGIC daily verification check is performed in the same rain conditions. If conditions change, additional OGIC daily verification checks will be conducted prior to the survey.

2.1.2.3 Temperature

Monitoring personnel will record the ambient temperature during the OGIC daily verification check and will confirm that the temperature is within the acceptable operating range of the OGIC. In the unlikely event that temperature within the survey area falls outside of the acceptable operating range of the OGIC, the survey will be postponed until acceptable operating conditions exist.

2.1.3 Thermal Background

The ability to easily identify fugitive emissions using an OGIC decreases as the thermal energy differential between the fugitive emission and background decreases. Monitoring personnel will view components within the field of view using multiple camera angles and will select an angle that provides an adequate thermal background. During the survey, monitoring personnel will continuously perform a qualitative analysis of the thermal properties of the background to ensure that adequate thermal background is present. If monitoring personnel identify an area where questionable thermal background is present that may reduce the detection capabilities of the OGIC, one or both of the following procedures will be followed.

1) An additional OGIC verification check will be performed in the area of question to verify that adequate thermal background is present.

2) A temporary background (e.g., a person or other background) will be inserted into the scene(s) to create an adequate thermal background when feasible to increase the thermal energy differential between the fugitive emission and the background.

2.1.4 Handling Interferences

Monitoring personnel will be knowledgeable of the process streams typically present at a LNG facility and specifically present at the site being surveyed and will be able to identify sources of potential interference, such as steam. If potential interference is identified, monitoring personnel will utilize alternate viewing angles to differentiate between the component and potential interference source. In addition, monitoring personnel may utilize a secondary confirmation instrument (e.g., handheld gas detector or bubbles) to confirm the presence of hydrocarbons in the emissions of interest.

2.1.5 OGIC Operator Training and Experience

OGIC monitoring will be performed by personnel that are trained in the proper operation of the OGIC to be used in the survey and that have prior experience using OGICs for the purposes of identifying fugitive emissions. All OGIC operators will meet the minimum training requirements of 30 TAC §115.358(h).

2.1.6 OGIC Maintenance

Maintenance of the OGIC will be performed in accordance with manufacturer's recommendations. Records of maintenance, as applicable, will be maintained by the OGIC owner/operator.

OGICs are not calibrated like a traditional Method 21 gas analyzer. However, performance is verified as previously described on at least a daily basis when used for monitoring. If the OGIC malfunctions, it will be sent to the manufacturer for repair or replacement.

Date: August 15, 2019

Emission Sources - Maximum Allowable Emission Rates

Permit Number 104840 and N170

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 (5)	
			lbs/hour	TPY (4)
65B-81A	Heating Medium Heater A	NO_x	0.80	-
		CO	2.44	-
		VOC	1.00	-
		PM	0.92	-
		PM_{10}	0.92	-
		$PM_{2.5}$	0.92	-
		SO_2	1.98	-
		H_2SO_4 (7)	0.15	-
65B-81B	Heating Medium Heater B	NO_x	0.80	-
		CO	2.44	-
		VOC	1.00	-
		PM	0.92	-
		PM_{10}	0.92	-
		$PM_{2.5}$	0.92	-
		SO_2	1.98	-
		H_2SO_4 (7)	0.15	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
65B-81C	Heating Medium Heater C	NO_x	0.80	-
		CO	2.44	-
		VOC	1.00	-
		PM	0.92	-
		PM_{10}	0.92	-
		$PM_{2.5}$	0.92	-
		SO_2	1.98	-
		H_2SO_4 (7)	0.15	-
65B-81D	Heating Medium Heater D	NO_x	0.80	-
		CO	2.44	-
		VOC	1.00	-
		PM	0.92	-
		PM_{10}	0.92	-
		$PM_{2.5}$	0.92	-
		SO_2	1.98	-
		H_2SO_4	0.15	-
65B-81E	Heating Medium Heater E	NO_x	0.80	-
		CO	2.44	-
		VOC	1.00	-
		PM	0.92	-
		PM_{10}	0.92	-
		$PM_{2.5}$	0.92	-
		SO_2	1.98	-
		H_2SO_4 (7)	0.15	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
65B-81A through 81E	Heating Medium Heaters, A through E Annual Emission Cap	NO_x	-	4.58
		CO	-	13.94
		VOC	-	5.70
		PM	-	5.29
		PM_{10}	-	5.29
		$PM_{2.5}$	-	5.29
		SO_2	-	11.33
		H_2SO_4 (7)	-	0.87
69B-81A	Heating Medium Heater 69A	NO_x	0.32	-
		CO	0.49	-
		VOC	0.25	-
		PM	0.92	-
		PM_{10}	0.92	-
		$PM_{2.5}$	0.92	-
		SO_2	1.98	-
		H_2SO_4 (7)	0.15	-
		NH_3	0.62	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates (5)**	
			lbs/hour	**TPY (4)**
69B-81B	Heating Medium Heater 69B	NO_x	0.32	-
		CO	0.49	-
		VOC	0.25	-
		PM	0.92	-
		PM_{10}	0.92	-
		$PM_{2.5}$	0.92	-
		SO_2	1.98	-
		H_2SO_4 (7)	0.15	-
		NH_3	0.62	-
69B-81C	Heating Medium Heater 69C	NO_x	0.32	-
		CO	0.49	-
		VOC	0.25	-
		PM	0.92	-
		PM_{10}	0.92	-
		$PM_{2.5}$	0.92	-
		SO_2	1.98	-
		H_2SO_4 (7)	0.15	-
		NH_3	0.62	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates (5)**	
			lbs/hour	**TPY (4)**
69B-81A through 81C	Heating Medium Heaters, A through C Annual Emission Cap	NO_x	-	2.80
		CO	-	4.27
		VOC	-	2.18
		PM	-	8.09
		PM_{10}	-	8.09
		$PM_{2.5}$	-	8.09
		SO_2	-	17.34
		H_2SO_4 (7)	-	1.33
		NH_3	-	5.43
TO1	Amine Unit/Thermal Oxidizer 61	NO_x	0.28	1.21
		CO	2.91	12.76
		VOC	2.12	2.42
		PM	1.29	5.65
		PM_{10}	1.29	5.65
		$PM_{2.5}$	1.29	5.65
		SO_2	1.08	4.72
		H_2SO_4 (7)	0.08	0.36
		H_2S	0.12	0.54

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
TO2	Amine Unit/Thermal Oxidizer 62	NO_x	0.28	1.21
		CO	2.91	12.76
		VOC	2.12	2.42
		PM	1.29	5.65
		PM_{10}	1.29	5.65
		$PM_{2.5}$	1.29	5.65
		SO_2	1.08	4.72
		H_2SO_4 (7)	0.08	0.36
		H_2S	0.12	0.54
TO3	Amine Unit/Thermal Oxidizer 63	NO_x	0.28	1.21
		CO	2.91	12.76
		VOC	2.12	2.42
		PM	1.29	5.65
		PM_{10}	1.29	5.65
		$PM_{2.5}$	1.29	5.65
		SO_2	1.08	4.72
		H_2SO_4 (7)	0.08	0.36
		H_2S	0.12	0.54

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
TO4	Amine Unit/Thermal Oxidizer 64	NO_x	0.28	1.21
		CO	2.91	12.76
		VOC	2.12	2.42
		PM	1.29	5.65
		PM_{10}	1.29	5.65
		$PM_{2.5}$	1.29	5.65
		SO_2	1.08	4.72
		H_2SO_4 (7)	0.08	0.36
		H_2S	0.12	0.54

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
CT	Combustion Turbine	NO_x	8.09	30.73
		NO_x (MSS)	87.00	
		CO	9.85	37.07
		CO (MSS)	57.00	
		VOC	0.34	1.27
		VOC (MSS)	1.27	
		PM	10.00	43.80
		PM (MSS)	2.90	
		PM_{10}	10.00	43.80
		PM_{10} (MSS)	2.90	
		$PM_{2.5}$	10.00	43.80
		$PM_{2.5}$ (MSS)	2.90	
		SO_2	4.08	11.98
		H_2SO_4 (7)	0.43	0.73
		NH_3	14.95	56.27
LUBVENT	Lube Oil Vent	VOC	0.05	0.22
		PM	0.05	0.22
		PM_{10}	0.05	0.22
		$PM_{2.5}$	0.05	0.22
PTFFLARE	PTF Flare (Before construction of flare gas recovery and Train 4)	NO_x	149.31	39.60
		NO_x(MSS)	2010.41	
		CO	594.63	155.37
		CO (MSS)	8006.66	
		VOC	39.15	1.36

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
		VOC(MSS)	420.38	
		SO_2	5.37	1.47
		SO_2(MSS)	52.66	
		H_2S	0.01	<0.01
		H_2S(MSS)	0.11	
PTFFLARE	PTF Flare (Before construction of Train 4 and after construction of flare gas recovery)	NO_x	0.27	4.99
		NO_x(MSS)	1861.37	
		CO	1.06	19.88
		CO (MSS)	7413.09	
		VOC	0.05	0.22
		VOC(MSS)	381.28	
		SO_2	0.01	0.23
		SO_2(MSS)	47.30	
		H_2S	<0.01	<0.01
		H_2S(MSS)	0.10	
PTFFLARE	PTF Flare (After construction of Train 4 and flare gas recovery)	NO_x	0.27	5.47
		NO_x(MSS)	2037.28	
		CO	1.06	21.78
		CO (MSS)	8113.70	
		VOC	0.05	0.49
		VOC(MSS)	479.64	
		SO_2	0.01	0.23
		SO_2(MSS)	47.31	
		H_2S	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
		H_2S(MSS)	0.10	
PTFFWP	Fire Water Pump	NO_x	2.56	0.13
		CO	0.67	0.03
		VOC	0.09	<0.01
		PM	0.08	<0.01
		PM_{10}	0.08	<0.01
		$PM_{2.5}$	0.08	<0.01
		SO_2	<0.01	<0.01
		H_2SO_4 (7)	<0.01	<0.01
PTFFWP2	Fire Water Pump Train 4	NO_x	2.56	0.13
		CO	0.67	0.03
		VOC	0.09	<0.01
		PM	0.08	<0.01
		PM_{10}	0.08	<0.01
		$PM_{2.5}$	0.08	<0.01
		SO_2	<0.01	<0.01
		H_2SO_4 (7)	<0.01	<0.01
PTFEG-1	Emergency Generator (DFEJ)	NO_x	8.57	0.21
		CO	0.70	0.02
		VOC	0.13	<0.01
		PM	0.05	<0.01
		PM_{10}	0.05	<0.01
		$PM_{2.5}$	0.05	<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 (5)	
			lbs/hour	TPY (4)
		H_2SO_4 (7)	<0.01	<0.01
PTFEG-2	Emergency Generator (DFEJ)	NO_x	8.57	0.21
		CO	0.70	0.02
		VOC	0.13	<0.01
		PM	0.05	<0.01
		PM_{10}	0.05	<0.01
		$PM_{2.5}$	0.05	<0.01
		SO_2	<0.01	<0.01
		H_2SO_4 (7)	<0.01	<0.01
PTFEG-3	Emergency Generator (DFEJ)	NO_x	8.57	0.21
		CO	0.70	0.02
		VOC	0.13	<0.01
		PM	0.05	<0.01
		PM_{10}	0.05	<0.01
		$PM_{2.5}$	0.05	<0.01
		SO_2	<0.01	<0.01
		H_2SO_4	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
PTFEG-4	Emergency Generator (DQFAH)	NO_x	1.38	0.03
		CO	2.00	0.05
		VOC	0.13	<0.01
		PM	0.07	<0.01
		PM_{10}	0.07	<0.01
		$PM_{2.5}$	0.07	<0.01
		SO_2	0.02	<0.01
		H_2SO_4	<0.01	<0.01
		NH_3	0.51	0.01
PTFEG-5	Emergency Generator (DQFAH)	NO_x	1.38	0.03
		CO	2.00	0.05
		VOC	0.13	<0.01
		PM	0.07	<0.01
		PM_{10}	0.07	<0.01
		$PM_{2.5}$	0.07	<0.01
		SO_2	0.02	<0.01
		H_2SO_4	<0.01	<0.01
		NH_3	0.51	0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
PTFEG-6	Emergency Generator (DFEJ)	NO_x	8.57	0.21
		CO	0.70	0.02
		VOC	0.13	<0.01
		PM	0.05	<0.01
		PM_{10}	0.05	<0.01
		$PM_{2.5}$	0.05	<0.01
		SO_2	<0.01	<0.01
		H_2SO_4	<0.01	<0.01
PTFEAC-1	Emergency Air Compressor	NO_x	1.87	0.05
		CO	1.73	0.04
		VOC	0.10	<0.01
		PM	0.10	<0.01
		PM_{10}	0.10	<0.01
		$PM_{2.5}$	0.10	<0.01
		SO_2	<0.01	<0.01
		H_2SO_4	<0.01	<0.01
		NH_3	0.14	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
PTFEAC-2	Emergency Air Compressor	NO_x	1.87	0.05
		CO	1.73	0.04
		VOC	0.10	<0.01
		PM	0.10	<0.01
		PM_{10}	0.10	<0.01
		$PM_{2.5}$	0.10	<0.01
		SO_2	<0.01	<0.01
		H_2SO_4	<0.01	<0.01
		NH_3	0.14	<0.01
FUG-TREAT	Pretreatment 1-3 VOC Fugitives (6)	VOC	1.05	4.62
		VOC (8)	1.08	4.72
		H2S	<0.01	<0.01
FUG-TRN4	Pretreatment Train 4 VOC Fugitives (6)	VOC	0.35	1.54
		VOC (8)	0.39	1.71
		H2S	<0.01	<0.01
FUG-CT	Pretreatment Ammonia Fugitives (6)	NH_3	0.12	0.51
FUG-HTR	Heater Ammonia Fugitives (6)	NH_3	0.12	0.51
67Z-97-Z1	Ammonia Loading	NH_3	<0.01	<0.01
PTFSOT	Slop Oil Tank	VOC	<0.01	<0.01
PTFOWT	Oily Water Tank	VOC	<0.01	<0.01
PTFHMT	Heating Medium Tank	VOC	3.57	0.01
PTFSOT-T4	Slop Oil Tank	VOC	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
PTFOWT-T4	Oily Water Tank	VOC	<0.01	<0.01
PTFHMT-T4	Heating Medium Tank	VOC	3.57	0.01
67T-90	Amine Storage Tank	VOC	<0.01	<0.01
PTFFWPT-1	Diesel Firewater Pump Tank	VOC	0.01	<0.01
PTFFWPT-2	Diesel Firewater Pump Tank 2	VOC	0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
PTFEGT-1	Diesel Emergency Generator (DFEJ) Tank	VOC	0.01	<0.01
PTFEGT-2	Diesel Emergency Generator (DFEJ) Tank	VOC	0.01	<0.01
PTFEGT-3	Diesel Emergency Generator (DFEJ) Tank	VOC	0.01	<0.01
PTFEGT-4	Diesel Emergency Generator (DQFAH) Tank	VOC	0.01	<0.01
PTFEGT-5	Diesel Emergency Generator (DQFAH) Tank	VOC	0.01	<0.01
PTFEGT-6	Diesel Emergency Generator (DFEJ) Tank	VOC	0.01	<0.01
PTFEACT-1	Diesel Emergency Air Compressor Tank	VOC	0.01	<0.01
PTFEACT-2	Diesel Emergency Air Compressor Tank	VOC	0.01	<0.01
60K-11A	Booster Compressors Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
60K-11B	Booster Compressors Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
60K-11C	Booster Compressors Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates (5)**	
			lbs/hour	**TPY (4)**
69K-11A	Booster Compressors Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
60K-11ATK	Lube Oil Run Down Tank	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
60K-11BTK	Lube Oil Run Down Tank	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
60K-11CTK	Lube Oil Run Down Tank	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
69K-11ATK	Lube Oil Run Down Tank	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
60K-40A	Residue Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
60K-40B	Residue Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
60K-40C	Residue Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
69K-40A	Residue Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
60K40ATK	Lube Oil Run Down Tank Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
60K40BTK	Lube Oil Run Down Tank Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
60K40CTK	Lube Oil Run Down Tank Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
69K40CTK	Lube Oil Run Down Tank Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
61K-43A	Debutanizer Overhead Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
61K-43B	Debutanizer Overhead Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
62K-43A	Debutanizer Overhead Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
62K-43B	Debutanizer Overhead Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
63K-43A	Debutanizer Overhead Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
63K-43B	Debutanizer Overhead Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
64K-43A	Debutanizer Overhead Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
64K-43B	Debutanizer Overhead Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
61K-30	Regen Gas Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
62K-30	Regen Gas Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
63K-30	Regen Gas Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (5)	
			lbs/hour	TPY (4)
64K-40	Regen Gas Compressor Lube Oil Vent	VOC	<0.01	<0.01
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<0.01	<0.01
MSS-FUG1-3	Fugitives - Train 1- 3 Vessel Opening for Maintenance	VOC	5.05	0.01
		H_2S	<0.01	<0.01
MSS-FUG4	Fugitives - Train 4 Vessel Opening for Maintenance	VOC	5.05	<0.01
		H_2S	<0.01	<0.01
All	Sitewide Emissions	Individual HAPs	---	10.00
		Total HAPs	---	25.00

(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) NO_x - total oxides of nitrogen
CO - carbon monoxide
VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
SO_2 - sulfur dioxide
H_2SO_4 - sulfuric acid mist
H_2S - hydrogen sulfide
NH_3 - ammonia
MSS - maintenance, startup, and shutdown
HAPs - hazardous air pollutant as listed in § 112(b) of the Federal Clean Air Act or Title 40 Code of Federal Regulations Part 63, Subpart C
(4) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period. Annual emission rates for each source include planned SS emissions.
(5) Planned startup and shutdown (SS) lbs/hr emission for pollutants are authorized even if not specifically identified as SS.
(6) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.
(7) Sulfuric acid mist is a subset of PM2.5 emissions.
(8) After construction of the flare gas recovery project.

Date: TBD

Permit Amendment
Source Analysis & Technical Review

Company	**Freeport LNG Development, L.P.**	Permit Numbers	**104840 and N170M1**
City	**Freeport**	Project Number	**346088**
County	**Brazoria**	Regulated Entity Number	**RN106481500**
Project Type	**Amendment**	Customer Reference Number	**CN601720345**
Project Reviewer	**Samuel Harris and Cara Hill**	Received Date	**August 9, 2022**
Site Name	**Freeport LNG Pretreatment Facility**		

Project Overview

Freeport LNG Development, L.P. (Freeport LNG) owns and operates a natural gas pretreatment plant in Quintana, Brazoria County, Texas. Freeport LNG submitted an amendment application requesting "as-built" changes. No Permit by Rule (PBR) or Standard Permit (SP) requires incorporation during this permitting action. Maintenance, startup, and shutdown (MSS) emissions are authorized under this permit.

Emission Summary

Air Contaminant	Current Allowable Emission Rates (tpy)	Proposed Allowable Emission Rates (tpy)	Change in Allowable Emission Rates (tpy)	Project Changes at Major Sources (Baseline Actual to Allowable)	Project Changes at Major Sources (Baseline Actual to Allowable)
				Train 1-3	Train 4
PM	80.83	80.83	0.00	66.45	80.26
PM_{10}	80.83	80.83	0.00	66.45	80.26
$PM_{2.5}$	80.83	80.83	0.00	66.45	80.26
VOC	23.36	27.79	4.43	20.51	7.39
NO_X	45.87	95.82	49.95	79.42	4.88
CO	109.96	309.85	199.89	244.91	19.02
SO_2	25.17	61.52	36.35	38.95	22.07
H_2SO_4	1.83	4.47	2.64	2.69	1.69
NH_3	62.77	62.77	0.00	N/A	N/A
H_2S	0.97	2.21	1.24	1.62	0.54

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	August 22, 2022
Site rating & classification:	7.53 / Satisfactory
Company rating & classification:	5.42 / Satisfactory
Has the permit changed on the basis of the compliance history or rating?	No
Did the Regional Office have any comments? If so, explain.	No

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Public Notice Information

Requirement	Date
Legislator letters mailed	8/18/2022
Date 1st notice published	08/31/2022
Publication Name: *The Facts*	
Pollutants: ammonia, carbon monoxide, hazardous air pollutants, hydrogen sulfide, nitrogen oxides, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, sulfur dioxide and sulfuric acid mist	
Date 1st notice Alternate Language published	09/01/2022
Publication Name (Alternate Language): *La Voz*	
1st public notice tearsheet(s) received	09/08/2022
1st public notice affidavit(s) received	09/15/2022
1st public notice certification of sign posting/application availability received	10/05/2022
SB709 Notification mailed	10/18/2022 (re-notice 4/14/2025)
Date 2nd notice published	
Publication Name:	
Pollutants:	
Date 2nd notice published (Alternate Language)	
Publication Name (Alternate Language):	
2nd public notice tearsheet(s) received	
2nd public notice affidavit(s) received	
2nd public notice certification of sign posting/application availability received	

Public Interest

Number of comments received	1
Number of meeting requests received	0
Number of hearing requests received	1
Date meeting held	
Date response to comments filed with OCC	
Date of SOAH hearing	

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Federal Rules Applicability

Subject to NSPS?	**Yes**
Subparts **A, Db, KKKK, & IIII**	
Subject to NESHAP?	**No**
Subparts **N/A**	
Subject to NESHAP (MACT) for source categories?	**Yes**
Subparts **A & ZZZZ**	

Nonattainment review applicability:
The plant is located in Brazoria County, which is located in an area that is currently designated serious nonattainment for ozone as of September 23, 2019. Trains 1-3 and Train 4 will be reviewed retrospectively with the major source threshold of 25 tpy for NO_X and VOCs for a severe nonattainment area under the previous 1997 8-hour ozone standard. See the Project Scope section for a detailed explanation of the project aggregation determination. NNSR applies to VOC for Trains 1-3.

Retrospective Train 1-3 review

	NO_x (tpy)	VOC (tpy)
Project increase	44.82	19.91
NNSR threshold	25	25

Retrospective Train 4 review

	NO_x (tpy)	VOC (tpy)
Project increase	4.88	7.39
NNSR threshold	25	25

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Requirement

PSD review applicability:
The plant is located in Brazoria County, which is located in an area that is currently designated serious nonattainment for ozone as of September 23, 2019. Trains 1-3 and Train 4 will be reviewed retrospectively with the major source threshold of 25 tpy for NO_X and VOCs for a severe nonattainment area under the previous 1997 8-hour ozone standard. See the Project Scope section for a detailed explanation of the project aggregation determination. The project increases do not exceed the thresholds as shown below. PSD review is not applicable.

Retrospective Train 1-3 review

	NO_x (tpy)	CO (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	H_2SO_4 (tpy)	H_2S (tpy)
Project increase	44.82	109.41	66.45	66.45	66.45	37.71	2.96	1.62
PSD threshold	250	250	250	250	250	250	250	250

Retrospective Train 4 review

	NO_x (tpy)	CO (tpy)	VOC (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	SO_2 (tpy)	H_2SO_4 (tpy)	H_2S (tpy)
Project increase	4.88	19.02	7.39	80.26	80.26	80.26	22.07	1.69	0.54
PSD threshold	250	250	250	250	250	250	250	250	250

Title V Applicability - 30 TAC Chapter 122 Rules

Requirement

Title V applicability:
The site is subject to the Title V program because it is a major source. The facility currently operates under Site Operating Permit No. O-2878.

Periodic Monitoring (PM) applicability:
Periodic Monitoring is applicable because the site is a major source. The following provisions for monitoring are being included in the special conditions:

- Continuous monitoring of flow rate and Btu content of the waste gas for the flare
- 28LAER LDAR program or OGI monitoring for the fugitives
- Continuous monitoring of the firebox temperature for the thermal oxidizers
- Standard MSS monitoring.

Compliance Assurance Monitoring (CAM) applicability:
The site is subject to Title V permitting requirements. The flares and thermal oxidizers are control devices used to achieve compliance with an applicable requirement of the permit, and control emissions sources with a pre-control emission rate in excess of an applicable major source threshold. CAM for the flares is addressed by continuous flow and composition monitoring. CAM for the thermal oxidizers is addressed by continuous temperature monitoring. The capture system is required to be inspected annually in accordance with 40 CFR Part 60, Appendix A, Test Method 21 and the bypass monitored.

Process Description

Raw pipeline gas arrives at Freeport LNG's existing Stratton Ridge meter station. The gas flows from the metering station, through Freeport LNG's existing 42-inch pipeline, and into the Pretreatment Facility where it is compressed by electrically powered booster compressors before being diverted to each of the four pretreatment trains. Each train can process approximately 823 million standard cubic feet per day (MMscfd) of incoming natural gas treatment capacity. Actual natural

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gas throughputs may vary from year to year.

In each pretreatment train, mercury is removed to protect aluminum-based heat exchangers. The gas is then compressed to meet the downstream NGL recovery plant requirements. Following compression, an amine unit removes CO2, hydrogen sulfide (H2S) and other sulfur and light organic compounds (e.g., benzene, toluene, and xylene) in order to satisfy the downstream liquefaction system requirements. Stripped CO2, H2S, and the other sulfur and organic compounds in the stream are routed to the RTOs (Unit ID Nos. TO1 through TO4), one per train.

After compression and amine treatment, water is removed from the gas in a molecular sieve dehydration system. The treated gas is sent to an NGL recovery system which removes heavy hydrocarbons (i.e., C5+ components) from the dry, treated gas prior to liquefaction. The NGL system is a closed-loop system; vapor reliefs of fluids lighter than air are collected in a flare header and routed to the cold flare scrubber (knock-out pot). The scrubber knocks out any liquids generated during relief conditions. Vapor from the scrubber is vented to the Cold Flare (Unit ID No. PTFFLARE). Any liquids (water or hydrocarbon) collected at the inlet separator, inlet filter coalescer, amine flash drum, low pressure fuel scrubber, or the cold flare scrubber are routed to slop and oily-water tanks (Unit ID Nos. PTFSOT, PTFOWT, PTFSOT-T4, and PTFOWT-T4), after passing through the closed drain drums. Gas released from liquids passing through the closed drain drums vent to the Warm Flare (Unit ID No. PTFFLARE). The site also includes stormceptor units to capture stormwater, spills, or exterior surface cleanup waters.

Heavier hydrocarbon components (e.g., C5+) present in the natural gas feed to the Pretreatment Facility are removed to prevent freezing within the downstream liquefaction process at Quintana Island. The NGL extraction process consists of a gas-gas exchanger where the natural gas feed is chilled against the cold stream from the absorber overhead. The residue gas from the gas-gas exchanger is sent to the dehydration feed cooler for energy recovery before being compressed by the residue gas compressors and cooled for transportation via pipeline to the liquefaction units on Quintana Island.

Trains 1 through 3 are supported by five heating medium heaters (Unit ID Nos. 65B-81A through 65B-81E) at the Pretreatment Facility. The heaters operate in coordination with the combustion turbine waste heat recovery unit. The waste heat recovery unit is used to transfer heat to the heating medium oil. The hot oil is used in the amine treatment units and dehydration system units in lieu of burning natural gas fuel in the heating medium heaters. The heaters for Trains 1–3 are used to supplement or replace the energy from the gas turbine waste heat recovery unit for use in the Pretreatment Trains 1–3. When the combustion turbine (Unit ID No. CT) is in operation, only one of these heaters (or the equivalent of one heater) will operate. The use of all five heaters simultaneously is necessary only when the combustion turbine is not operational. Three additional heaters (Unit ID Nos. 69B-81A through 69B-81C) are used to support the amine treatment unit and dehydration system unit in Train 4, which does not rely on waste heat provided by the combustion turbine.

The RTOs (Unit ID Nos. TO1 through TO4) are equipped with gas-fired, low-NOX burners that are typically used for initial unit start-up (cold-start) only. Once the burners heat the RTOs to the required operating temperature and the heat content of the incoming process gas stream is sufficient to sustain combustion, the burners shut off. Due to the abundant oxygen content of the process gas, complete combustion readily occurs when the ignition point is reached in the oxidizer. Boil off gas (BOG) or natural gas is fired, as necessary, to supplement the combustion heat requirements of the RTOs and maintain the proper combustion temperatures.

Freeport LNG utilizes a ground flare system (Unit ID No. PTFFLARE) to serve the four gas processing trains at the site. The ground flare consists of a Warm Flare System and a Cold Flare System. The flare systems (both warm ground flare system and cold ground flare system) are common systems that are sized to safely handle flaring scenarios from the processing trains. In general, the warm flare system handles relief sources that are greater than 32 °F in temperature. A knockout drum is provided to catch entrained liquid, which is pumped to the oily water tank for disposal. The cold flare handles relief sources that are colder than 32 °F. A knockout drum is also provided to contain entrained liquid which is pumped and combined with the NGL product. Both the Warm and Cold Flare Systems are pressure-assisted, multi-point ground flares that are located in a common enclosed radiation fence. The ground flare system controls vent streams associated with maintenance, start-up, and shutdown (MSS) activities (Unit ID No. PTFFLRMSS); pressure safety valves (PSVs), compressor seals, and pump seals for Trains 1 through 3 (Unit ID No. PTFFLRPSV); and PSVs, compressor seals, and pump seals for Train 4 (Unit ID No. PTF4FLRPSV).

The Pretreatment Facility includes one General Electric (GE) Frame 7EA simple cycle, natural gas-fired combustion turbine (Unit ID No. CT) exhausting to a heat exchanger for waste heat recovery. The combustion turbine has a nominal base-load gross electric power output of approximately 87 megawatts. The waste heat recovery unit is used to transfer heat to the heating medium oil. The hot oil is used in the amine treatment units and dehydration system units in lieu of burning natural gas fuel in the heating medium heaters for use in these units. Freeport LNG uses a dry low-NOX combustor and Selective Catalytic Reduction (SCR) to reduce NOX emissions from the combustion turbine system. The SCR uses aqueous ammonia as the reagent, where the catalyst facilitates the reaction of the ammonia with NOX to create nitrogen and water. Emissions of carbon monoxide and volatile organic compounds (VOCs) from the CT exhaust are additionally controlled by an Oxidation Catalyst (Ox-Cat).

The combustion turbine, booster compressors and residue compressors include closed-loop lubrication oil recirculation systems to lubricate moving parts of the equipment. Oil vapor (as VOC) and oil mist (as particulate matter [PM]) emissions may be generated by oil vaporization resulting from heating of the lubrication oil in the equipment and subsequent condensation of the droplets when the vapor is cooled in the cooler zones of the storage reservoir compartments. Lubrication oil mist emissions from each reservoir compartment are controlled by a mist eliminator exhausted through dedicated reservoir vents (Unit ID Nos. LUBVENT, 60K-11A, 60K-11B, 60K-11C, 69K-11A, 60K-11ATK, 60K-11BTK, 60K-11CTK, 69K-11ATK, 60K-40A, 60K-40B, 60K-40C, 69K-40A, 60K-40ATK, 60K-40BTK, 60K-40CTK, 69K-40ATK, 61K-43A, 61K-43B, 62K-43A, 62K-43B, 63K-43A, 63K-43B, 64K-43A, 64K-43B, 61K-30, 62K-30, 63K-30, and 64K-30).

In support of the operations at the site, six emergency generator engines (Unit ID Nos. PTFEG-1 through PTFEG-6) are available to serve as a reliable power source for lighting and other emergency equipment in the event of a power failure. Two emergency firewater pumps powered by diesel-fired engines (Unit ID Nos. PTFFWP and PTFFWP2) and two emergency air compressors powered by diesel-fired engines (Unit ID Nos. PTFEAC-1 and PTFEAC-2) are included at the site for emergency situations. Emergency engines PTFFWP2, PTFEG-6 and PTGEAC-2 are engines associated with the construction of Train 4. Each emergency generator engine and emergency air compressor engine is fired with ultra-low sulfur diesel fuel and is limited to 50 hours/year (hrs/yr) of operation for purposes of maintenance and testing. Each firewater pump engine is fired with ultra-low sulfur diesel fuel and limited to 100 hrs/yr of operation for purposes of maintenance and testing.

Ultra-low sulfur diesel fuel for the emergency engines is stored in small, day tanks integral or adjacent to the emergency generator, compressor, and firewater pump engines. The day tanks (Unit ID Nos. PTFFWPT-1, PTFFWPT-2, PTFEGT-1 through PTFEGT-6, PTFEACT-1, and PTFEACT-2) are fixed-roof tanks that are maintained with fuel in them at all times, in case of emergency. Tanks PTFEGT-6, PTFEACT-2, and PTFFWPT-2 are tanks associated with the installation of emergency engines PTFEG-6, PTFEAC-2, and PTFFWP2 and are therefore, associated with the construction of Train 4. The engines consume diesel fuel during periodic testing or during an emergency situation, and therefore, the associated diesel day tanks are refilled periodically.

Project Scope

Freeport LNG is requesting authorization for the following changes to the permitted representations of the Pretreatment Facility to accurately reflect the “as-built” site and current site operations:

- Streams controlled by the flare (EPN PTFFLARE), including those associated with seal gas venting and proposed MSS events that have become known through actual operation of these facilities;
- Adjustment to fugitive emissions estimates resulting from ground truthing of component counts and calculation methodology associated with fugitive components (EPNs FUG-TREAT and FUG-TRN4);
- Increase in sulfur dioxide emissions from the heaters (EPNs 65B-81A through 65B-81E and 69B-81A through 69B-81C) and RTOs (EPNs TO1 through TO4). This is a result of a proposed increase in allowance for sulfur compounds contained in the feed and fuel gas to allow for greater flexibility in operation; and
- Updates to miscellaneous representations presented with the previous permit applications.

Because these changes are being made to reflect the “as-built” units and current site operations, Freeport LNG is reevaluating major source applicability based on the proposed changes for each construction project (i.e., Trains 1-3 and separately, Train 4) in a retrospective analysis.

Freeport LNG is simultaneously proposing a flare gas recovery project to be authorized with this application. The flare gas recovery project includes the following:

- Flare gas recovery project, which will reduce seal gas vented to the flare; and
- The facilities, piping components, and other infrastructure which will result in increased fugitive component counts associated with this project.

Federal Applicability

This amendment is a retrospective review of the original three trains, a retrospective review of the unconstructed Train 4, and authorization of a flare gas recovery project. Trains 1-3 were initially authorized in Permit No. 104840 issued July 16, 2014, and began construction on February 15, 2015. Train 4 was initially authorized in amended Permit No. 104840 issued April 25, 2018. Train 4 project was conservatively aggregated with the Trains 1-3 project at time it was authorized resulting in NNSR Review for the Pretreatment Trains 1-4. Train 4 has only performed limited construction activities to support additional geotechnical engineering and does not anticipate commencement of full scale construction until early 2023 with operations likely in 2027, approximately 7 years after commencement of operation of Train 3. Because of this, Train 4 has taken on the form of a true incremental project to the original three-train project.

Since the proposed changes included in this application, except for the flare gas recovery project, are considered retrospective changes associated with the initial authorization of each emission unit, emissions from Trains 1-3 will be reviewed as if the site were greenfield (i.e., in the context of being initially permitted at these levels). Emissions from Train 4 will be evaluated as a separate addition to the site. The proposed flare gas recovery project is being evaluated as a separate project.

As a result of the flare gas recovery project that will be implemented at the site, annual and hourly emissions from the flare will decrease. There will be small increases of VOC associated with additional fugitive components (EPNs FUG TREAT and FUG TRN4) installed as part of these projects; however, the flare gas recovery project will result in an overall decrease of VOC emissions due to the proposed decrease in VOC emissions from the flare.

Special Conditions

A summary of the draft changes to the permit requirements, including control, monitoring, recordkeeping and reporting requirements, is given below.

SC No.	Comment
1	Incorporates MAERT and limits scope of authorization to sources listed on MAERT.
2	Generic prohibition on releases from uncontrolled process vents, limits on permit holder's ability to claim affirmative defense under 30 TAC Chap. 101 for releases from pressure relief devices.
5	Updates to flare conditions to reference the AMOC monitoring requirements.
6	Updates to limit on fuel gas sulfur content
8	Removal of duplicative conditions and revised reference for Tier 4 emissions standards in 40 CFR Part 1039.102
11	Update to heater operating scenario
19	Updates to SO_2 stack sampling of the thermal oxidizers
20	Updates to CEMS requirements
21	Updates to ammonia slip monitoring
31	Updates to bypass monitoring
35	Offset requirements
36	Records retention period.

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Best Available Control Technology and Lowest Achievable Emission Rate
New and modified sources of NO_X associated with the Trains 1-3 construction project are subject to a LAER analysis. The Train 4 construction project does not exceed NNSR major source thresholds and does not require a LAER analysis.

EPN	Source Name	Best Available Control Technology Description
65B-81A	Heating Medium Heater A	Freeport LNG has identified that sulfur inlet should be increased to better reflect potential variations in actual conditions and allow for greater flexibility in operation, which results in higher emissions of SO_2 and H_2SO_4 for all eight heaters. Emissions of SO_2 and H_2SO_4 are limited through the use of low-sulfur fuel.
65B-81B	Heating Medium Heater B	
65B-81C	Heating Medium Heater C	
65B-81D	Heating Medium Heater D	
65B-81E	Heating Medium Heater E	
69B-81A	Heating Medium Heater 69A	
69B-81B	Heating Medium Heater 69B	
69B-81C	Heating Medium Heater 69C	
TO1	Amine Unit / Thermal Oxidizer 61	Freeport LNG has identified that sulfur inlet should be increased to better reflect potential variations in actual conditions and allow for greater flexibility in operation, which results in higher emissions of SO_2 and H_2SO_4 for all eight heaters. Emissions of SO_2 and H_2SO_4 are limited through the use of low-sulfur fuel.
TO2	Amine Unit / Thermal Oxidizer 62	
TO3	Amine Unit / Thermal Oxidizer 63	
TO4	Amine Unit / Thermal Oxidizer 64	
PTFFLARE	PTF Flare	Emissions from the Ground Flare are being updated to reflect certain maintenance activities that have become known through actual operation of these facilities and were not represented in previous applications and the proposed flare gas recovery project. The flare is a pressure assisted, multi-staged, multi-point ground flare. The flare is designed to achieve 99.5 DRE for all VOC compounds in the vapor emissions routed to it. The flare is used to control MSS activities for Trains 1-3, including the planned shutdown and startup of one train in any one year for major maintenance turnaround purposes. Freeport LNG will continue to use good combustion practices while operating the flare to limit NO_X emissions to meet LAER. NO_X emissions from the flare are based on TCEQ's factors for high-British thermal unit (Btu) streams, based on flare stream characteristics. The flare meets the design and operating requirements of the AMOC Permit AMOC71. The flare is equipped with a flow monitor and continuous emissions analyzer to ensure compliance with these requirements. Based on an updated query of the RBLC database, permits, and other regulatory requirements (such as the California Air Resources Board (CARB) determinations and California air district rules) for similar flare operations, the operating practices and compliance with applicable regulatory requirements continue to meet LAER.
FUG-TREAT	Pretreatment Train 1-3 VOC Fugitives	Freeport LNG is updating pre-flare gas recovery fugitive component counts with this project to reflect the results of ground truthing of the component counts. Emissions from piping components will be limited through the use of the 28LAER LDAR requirements and an approved Optical Gas Imaging (OGI)
FUG-TRN4	Pretreatment Train 4 VOC Fugitives	

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EPN	Source Name	Best Available Control Technology Description
		monitoring alternative.
MSS-FUG1-3	Fugitives - Train 1- 3 Vessel Opening for Maintenance	LAER for the vessel opening is determined to be the following: minimizing of the number and duration of planned MSS events; MSS activities associated with large emissions from equipment containing materials with vapor pressures above 0.5 psia will be routed to the flare; Process equipment will only be opened for inspection and maintenance after purging to the flare to minimize VOC content down to 10,000 ppmv or 10% of the lower explosive level (LEL); and Use of knockout drums to separate liquids and vapors.
MSS-FUG4	Fugitives - Train 4 Vessel Opening for Maintenance	

Permits Incorporation

Permit by Rule (PBR) / Standard Permit / Permit Nos.	Description (include affected EPNs)	Action (Reference / Consolidate / Void)
N/A	N/A	N/A

Impacts Evaluation

Was modeling conducted? **Yes** Type of Modeling: **AERMOD**

Is the site within 3,000 feet of any school? **No**

Additional site/land use information:

Air dispersion modeling was performed by the applicant to evaluate total air emissions from the proposed project. Based on the results of the dispersion model, emissions from the site are not expected to result in a violation of any state or national ambient air quality standard. Emissions of non-criteria air contaminants are not expected to create adverse impacts to public health. The air dispersion modeling demonstration was audited by the TCEQ Air Dispersion Modeling Team and approved (memo dated June 21, 2023). A second modeling audit was conducted resulting from updates to the application (memo dated March 24, 2024). A detailed description of the air dispersion modeling performed is contained in the Preliminary Determination Summary.

Project Reviewer	Date	Team Leader	Date
Cara Hill		Joel Stanford	

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Compliance History Report

Compliance History Report for CN601720345, RN106481500, Rating Year 2022 which includes Compliance History (CH) components from September 1, 2017, through August 31, 2022.

Customer, Respondent, or Owner/Operator:	CN601720345, Freeport LNG Development, L.P.	**Classification:**	SATISFACTORY	**Rating:**	6.44
Regulated Entity:	RN106481500, FREEPORT LNG PRETREATMENT FACILITY	**Classification:**	SATISFACTORY	**Rating:**	9.00
Complexity Points:	18	**Repeat Violator:**	NO		
CH Group:	03 - Oil and Gas Extraction				
Location:	2363 CR 690 APPROXIMATELY 0.25 MI NORTH OF THE INTERSECTION OF CR 690 AND CR 891 BRAZORIA, TX, BRAZORIA COUNTY				
TCEQ Region:	REGION 12 - HOUSTON				

ID Number(s):

AIR OPERATING PERMITS PERMIT 3958
AIR NEW SOURCE PERMITS EPA PERMIT N170
AIR NEW SOURCE PERMITS PERMIT 104840
AIR NEW SOURCE PERMITS PERMIT AMOC71
AIR NEW SOURCE PERMITS EPA PERMIT N170M1
AIR NEW SOURCE PERMITS AFS NUM 4803900778
STORMWATER PERMIT TXR05GN49
WASTEWATER PERMIT WQ0005415000
WASTEWATER EPA ID TX0134056
AIR EMISSIONS INVENTORY ACCOUNT NUMBER BLA057E
POLLUTION PREVENTION PLANNING ID NUMBER P10583
INDUSTRIAL AND HAZARDOUS WASTE EPA ID TXR000085218
INDUSTRIAL AND HAZARDOUS WASTE SOLID WASTE REGISTRATION # (SWR) 97620
TAX RELIEF ID NUMBER 19421
TAX RELIEF ID NUMBER 20125
TAX RELIEF ID NUMBER 19452
TAX RELIEF ID NUMBER 19454
TAX RELIEF ID NUMBER 21050
TAX RELIEF ID NUMBER 23317
TAX RELIEF ID NUMBER 20126
TAX RELIEF ID NUMBER 19093
TAX RELIEF ID NUMBER 20122
TAX RELIEF ID NUMBER 20731
TAX RELIEF ID NUMBER 19514
TAX RELIEF ID NUMBER 20619
TAX RELIEF ID NUMBER 19453
TAX RELIEF ID NUMBER 20617
TAX RELIEF ID NUMBER 21019
TAX RELIEF ID NUMBER 20637
TAX RELIEF ID NUMBER 20621
TAX RELIEF ID NUMBER 20730
TAX RELIEF ID NUMBER 20127
TAX RELIEF ID NUMBER 20638
TAX RELIEF ID NUMBER 20620
TAX RELIEF ID NUMBER 20762
TAX RELIEF ID NUMBER 20626
TAX RELIEF ID NUMBER 20712
TAX RELIEF ID NUMBER 23291
TAX RELIEF ID NUMBER 23292
TAX RELIEF ID NUMBER 22501
TAX RELIEF ID NUMBER 22510
TAX RELIEF ID NUMBER 23290
TAX RELIEF ID NUMBER 23289
TAX RELIEF ID NUMBER 21950
TAX RELIEF ID NUMBER 22424
TAX RELIEF ID NUMBER 21953
TAX RELIEF ID NUMBER 24020

Compliance History Period: September 01, 2017 to August 31, 2022 **Rating Year:** 2022 **Rating Date:** 09/01/2022

Date Compliance History Report Prepared: November 20, 2025

Agency Decision Requiring Compliance History: Permit - Issuance, renewal, amendment, modification, denial, suspension, or revocation of a permit.

Component Period Selected: August 09, 2017 to August 09, 2022

TCEQ Staff Member to Contact for Additional Information Regarding This Compliance History.

Name: TCEQ Staff Member **Phone:** (512) 239-1000

Site and Owner/Operator History:

1) Has the site been in existence and/or operation for the full five year compliance period? YES

2) Has there been a (known) change in ownership/operator of the site during the compliance period? NO

Components (Multimedia) for the Site Are Listed in Sections A - J

A. Final Orders, court judgments, and consent decrees:

1 Effective Date: 08/25/2021 ADMINORDER 2020-1417-AIR-E (1660 Order-Agreed Order With Denial)

Classification: Moderate

Citation: 30 TAC Chapter 116, SubChapter B 116.115(c)
30 TAC Chapter 122, SubChapter B 122.143(4)
5C THSC Chapter 382 382.085(b)

Rqmt Prov: 8 OP
Special Condition 1 PERMIT

Description: Failure to prevent unauthorized emissions to the atmosphere during an emissions event that was discovered on August 23, 2019, TCEQ/STEERS Incident No. 319532 (Category A12.i.(6)).

Classification: Moderate

Citation: 30 TAC Chapter 116, SubChapter B 116.115(c)
30 TAC Chapter 122, SubChapter B 122.143(4)
5C THSC Chapter 382 382.085(b)

Rqmt Prov: AMOC-71 F.1 PERMIT
FOP Special Term & Condition (ST&C) 8 OP
NSR Special Condition (SC) 7H PERMIT

Description: Failure to maintain PTF flare (EPN: PTFFLARE) at or above 800 British thermal units per standard cubic foot (Btu/scf). [Category A12(i)(6)]

2 Effective Date: 11/16/2021 ADMINORDER 2021-0203-AIR-E (1660 Order-Agreed Order With Denial)

Classification: Moderate

Citation: 30 TAC Chapter 116, SubChapter B 116.115(c)
30 TAC Chapter 122, SubChapter B 122.143(4)
5C THSC Chapter 382 382.085(b)

Rqmt Prov: General Terms and Conditions OP
Special Condition 1 PERMIT
Special Terms and Conditions No. 8 OP

Description: Failed to to prevent unauthorized emissions. Specifically, the Respondent released 5,155.54 pounds ("lbs") of carbon monoxide, 55.93 lbs of nitrogen oxides, 0.01 lb of sulfuric acid, and 0.05 lb of sulfur dioxide from the Pretreatment Facility Flare, Emissions Point Number PTFFLARE, during an emissions event (Incident No. 344175) that occurred on October 18, 2020 and lasted ten hours.

B. Criminal convictions:

N/A

C. Chronic excessive emissions events:

N/A

D. The approval dates of investigations (CCEDS Inv. Track. No.):

Item 1	March 13, 2019	(1850881)
Item 2	April 25, 2019	(1850848)
Item 3	July 18, 2019	(1850860)
Item 4	November 08, 2019	(1850872)
Item 5	November 19, 2019	(1592392)
Item 6	January 23, 2020	(1850882)
Item 7	March 26, 2020	(1630072)
Item 8	April 14, 2020	(1850849)
Item 9	July 24, 2020	(1850861)
Item 10	July 26, 2020	(1850869)
Item 11	August 21, 2020	(1658828)
Item 12	January 25, 2021	(1850883)
Item 13	April 19, 2021	(1850850)
Item 14	June 03, 2021	(1724809)
Item 15	July 29, 2021	(1850870)

Item 16	July 30, 2021	(1850862)
Item 17	September 28, 2021	(1690657)
Item 18	October 27, 2021	(1850874)
Item 19	November 04, 2021	(1639715)
Item 20	January 18, 2022	(1850884)
Item 21	April 07, 2022	(1850851)
Item 22	May 20, 2022	(1796423)
Item 23	July 28, 2022	(1850863)

E. Written notices of violations (NOV) (CCEDS Inv. Track. No.):

A notice of violation represents a written allegation of a violation of a specific regulatory requirement from the commission to a regulated entity. A notice of violation is not a final enforcement action, nor proof that a violation has actually occurred.

N/A

F. Environmental audits:

N/A

G. Type of environmental management systems (EMSs):

N/A

H. Voluntary on-site compliance assessment dates:

N/A

I. Participation in a voluntary pollution reduction program:

N/A

J. Early compliance:

N/A

Sites Outside of Texas:

N/A

TCEQ Interoffice Memorandum

To: Cara Hill
Mechanical/Coatings Section

Thru: Chad Dumas, Team Leader
Air Dispersion Modeling Team (ADMT)

From: Ahmed Omar, P.E.
ADMT

Date: June 21, 2023

Subject: Air Quality Analysis Audit - Freeport LNG Development, L.P. (RN106481500)

1. Project Identification Information

Permit Application Number: 104840
NSR Project Number: 346088
ADMT Project Number: 8541
County: Brazoria
Published Map: \\tceq4avmgisdata\GISWRK\APD\MODEL PROJECTS\8541\8541.pdf

Air Quality Analysis: Submitted by Atkins North America, Inc., April 2023, on behalf of Freeport LNG Development, L.P. Additional modeling and information were provided May and June 2023.

2. Report Summary

The air quality analysis (AQA) is acceptable for all review types and pollutants. The results are summarized below.

This project evaluates the as-built changes to Train 1-3 and Train 4 (NSR project No. 264968 and 181065, WCC Content IDs 4878915 and 4984819). The applicant evaluated the projects sources from the beginning with the as-built changes incorporated. According to the applicant, since Train1-3 and Train 4 includes all emission sources at the site, the modeling demonstrations represent site-wide modeling.

A. Minor Source NSR and Air Toxics Analysis

Table 1. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	13	1021
H_2SO_4	1-hr	1	50
H_2SO_4	24-hr	0.7	15
H_2S	1-hr	0.4	108

Table 2. Modeling Results for Minor NSR De Minimis

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
SO_2	1-hr	13	7.8
SO_2	3-hr	13	25
NO_2	1-hr	29	7.5
NO_2	Annual	0.3	1
CO	1-hr	130	2000
CO	8-hr	38	500

The GLCmax are the maximum predicted concentrations associated with one year of meteorological data.

The applicant relied on guidance from EPA on evaluating intermittent emissions for the 1-hr NO_2 analysis. See section 4 for additional details.

The justification for selecting the EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels was 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.

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

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. = [Background + GLCmax] (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	13	18	31	196
NO_2	1-hr	29	25	54	188

The GLCmax are the maximum predicted concentrations associated with one year of meteorological data.

Background concentrations for SO_2 were obtained from the EPA AIRS monitor 480391607 located at 901 County Rd. 792 Oyster Creek, Brazoria County. The three-year average (2019-2021) of the 99th percentile of the annual distribution of the maximum daily 1-hr concentrations was used for the 1-hr value. ADMT reviewed monitoring data from most recent (2022) and verified that the applicant approach will not affect the overall modeling

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

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results. This monitor is reasonable based on the proximity of the monitor to the project site (three kilometers).

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 480391607 located at 901 County Rd. 792 Oyster Creek, Brazoria County. The three-year average (2019-2021) of the 98th percentile of the annual distribution of the daily maximum 1-hr concentrations was used for the 1-hr value. ADMT reviewed monitoring data from most recent (2022) and verified that the applicant approach will not affect the overall modeling results. This monitor is reasonable based on the proximity of the monitor to the project site (three kilometers).

3. Model Used and Modeling Techniques

AERMOD (Version 21112) was used in a refined screening mode. The most recent AERMOD version (Version 22112) should be used on all future submittals.

A unitized emission rate of 1 lb/hr was used to predict a generic short-term and long-term impact for each source. The generic impact was multiplied by the proposed pollutant specific emission rates to calculate a maximum predicted concentration for each source. The maximum predicted concentration for each source was summed to get a total predicted concentration for each pollutant. The total predicted concentrations were compared to 10 percent of their respective ESLs (step 3 of the MERA guidance). All pollutants meet step 3 of the MERA.

EPNs FUG-TREAT and FUG-TRN4 were divided into thirty-seven and five volume sources, respectively. A weighted unit impacts is calculated based on each volume source unit impact and proportion of total EPN emissions associated with each volume source. The calculated weighted unit impacts were used in the calculations described in the previous paragraph.

The applicant conducted the 1-hr and annual NO_2 NAAQS analyses using the ARM2 model option following EPA guidance.

A. Land Use

Medium roughness and elevated terrain were used in the modeling analysis. These selections are consistent with the AERSURFACE analysis, topographic maps, DEMs, and aerial photography. The selection of medium roughness is reasonable.

B. Meteorological Data

Surface Station and ID: Angleton, TX (Station #: 12976)
Upper Air Station and ID: Lake Charles, LA (Station #: 3937)
Meteorological Dataset: 2016
Profile Base Elevation: 7.3 meters

C. Receptor Grid

The grid modeled was sufficient in density and spatial coverage to capture representative maximum ground-level concentrations.

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D. Building Wake Effects (Downwash)

Input data to Building Profile Input Program Prime (Version 04274) are consistent with the aerial photography, plot plan, and modeling report.

4. Modeling Emissions Inventory

The modeled emission point and volume source parameters and rates were consistent with the modeling report. The source characterizations used to represent the sources were appropriate.

The computation of the effective stack diameters for the flares is consistent with TCEQ modeling guidance.

For H_2S analyses, the modeled sigma z for volume source, Model ID FUG63A, was not consistent with the reported sigma z; however, given the low predicted concentrations, it unlikely this inconsistency will affect the modeling results.

For the 1-hr NO_2 NAAQS analyses, emissions from six emergency generators (Model IDs PTFEG1 thru PTFEG6), two firewater pump engines (Model IDs PTFFWP and PTFFWP2), and two emergency air compressors (Model IDs PTFEAC1 and PTFEAC2) were modeled with an annual average emission rate, consistent with EPA guidance for evaluating intermittent emissions. The emergency diesel generators and the emergency air compressors will each operate no more than 50 hours per year, and the firewater pump engines will each operate no more than 100 hours per year. Since the project is located in the HGB ozone nonattainment area, the emergency engines cannot be tested between the hours of 6:00 am and 12:00 pm (Title 30 of the Texas Administrative Code Chapter § 117.2030(c)). The applicant considered this operational limitation in the determination of the annual average emission rates.

To account for abovementioned operational limitations, the modeled emission rates for six emergency generators (Model IDs PTFEG1 thru PTFEG6), two firewater pump engines (Model IDs PTFFWP and PTFFWP2), and two emergency air compressors (Model IDs PTFEAC1 and PTFEAC2) were multiplied by 0 during the hours of 6 am to 12 pm.

The applicant evaluated the start-up/shutdown emissions from the combustion turbine (EPN CT) based on EPA guidance for intermittent sources. The applicant modeled this source using an annual average emission rate for the 1-hr NO_2 NAAQS analysis. According to the applicant, the start-up/shutdown of the combustion turbine is an intermittent source: each start-up/shutdown event will last for 90 minutes or less and no more than six events per year.

Except as noted above, maximum allowable hourly emission rates were used for the short-term averaging time analyses, and annual average emission rates were used for the annual averaging time analyses.

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TCEQ Interoffice Memorandum

To: Cara Hill
Mechanical/Coatings Section

Thru: Chad Dumas, Team Leader
Air Dispersion Modeling Team (ADMT)

From: Ahmed Omar, P.E.
ADMT

Date: March 14, 2024

Subject: Second Air Quality Analysis Audit - Freeport LNG Development, L.P. (RN106481500)

1. Project Identification Information

Permit Application Number: 104840
NSR Project Number: 346088
ADMT Project Number: 9042
County: Brazoria
Published Map: \\tceq4avmgisdata\GISWRK\APD\MODEL PROJECTS\9042\9042.pdf

Air Quality Analysis: Submitted by Atkins North America, Inc., February 2024, on behalf of Freeport LNG Development, L.P. Additional modeling and information were provided March 2024.

2. Report Summary

The air quality analysis is acceptable for all review types and pollutants. The results are summarized below.

This is the second modeling audit for this NSR project number. The second modeling audit is conducted to review modeling due to additional as-built changes (adding EPN MSS-FUG) to the permitted representations of the Pretreatment Facility. The additional as-built changes only affected the H_2S state property line and health effects analysis. The applicant evaluated the project from the beginning with the as-built changes incorporated. This memo represents a complete summary and supersedes the previous audit memo dated June 21, 2023 (WCC content ID 6581554).

A. Minor Source NSR and Air Toxics Analysis

Table 1. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	13	1021
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H_2SO_4	24-hr	0.7	15
H_2S	1-hr	0.4	108

Table 2. Modeling Results for Minor NSR De Minimis

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
SO_2	1-hr	13	7.8
SO_2	3-hr	13	25
NO_2	1-hr	29	7.5
NO_2	Annual	0.3	1
CO	1-hr	130	2000
CO	8-hr	38	500

The GLCmax are the maximum predicted concentrations associated with one year of meteorological data.

The applicant relied on guidance from EPA on evaluating intermittent emissions for the 1-hr NO_2 analysis. See section 4 for additional details.

The justification for selecting the EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels was 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.

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

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. = [Background + GLCmax] (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	13	18	31	196
NO_2	1-hr	29	25	54	188

The GLCmax are the maximum predicted concentrations associated with one year of meteorological data.

Background concentrations for SO_2 were obtained from the EPA AIRS monitor 480391607 located at 901 County Rd. 792 Oyster Creek, Brazoria County. The three-year average (2019-2021) of the 99th percentile of the annual distribution of the maximum daily 1-hr concentrations was used for the 1-hr value. ADMT reviewed monitoring data from the most recent year (2022) and verified that the applicant approach will not affect the overall

[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

modeling results. This monitor is reasonable based on the proximity of the monitor to the project site (three kilometers).

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 480391607 located at 901 County Rd. 792 Oyster Creek, Brazoria County. The three-year average (2019-2021) of the 98th percentile of the annual distribution of the daily maximum 1-hr concentrations was used for the 1-hr value. ADMT reviewed monitoring data from the most recent year (2022) and verified that the applicant approach will not affect the overall modeling results. This monitor is reasonable based on the proximity of the monitor to the project site (three kilometers).

Table 4. Minor NSR Site-wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	ESL ($\mu g/m^3$)
Mercaptans	Not found	1-hr	6	18

The GLCmax is based on generic modeling (see section 3 for more details).

3. Model Used and Modeling Techniques

AERMOD (Version 21112) was used in a refined screening mode. The most recent AERMOD version (Version 23132) should be used on all future submittals.

A unitized emission rate of 1 lb/hr was used to predict a generic short-term and long-term impact for each source. The generic impact was multiplied by the proposed pollutant specific emission rates to calculate a maximum predicted concentration for each source. The maximum predicted concentration for each source was summed to get a total predicted concentration for each pollutant. The total predicted concentrations were compared to 10 percent of their respective ESLs (step 3 of the MERA guidance). All pollutants meet step 3 of the MERA except 1-hr mercaptans.

EPNs FUG-TREAT and FUG-TRN4 were divided into thirty-seven and five volume sources, respectively. A weighted unit impacts is calculated based on each volume source unit impact and proportion of total EPN emissions associated with each volume source. The calculated weighted unit impacts were used in the calculations described in the previous paragraph.

Model ID MSS_FUG represents multiple EPNs. According to the applicant, the modeled location represents the closest location of the emissions to the property line.

The applicant conducted the 1-hr and annual NO_2 NAAQS analyses using the ARM2 model option following EPA guidance.

A. Land Use

Medium roughness and elevated terrain were used in the modeling analysis. These selections are consistent with the AERSURFACE analysis, topographic maps, DEMs, and aerial photography. The selection of medium roughness is reasonable.

B. Meteorological Data

Surface Station and ID: Angleton, TX (Station #: 12976)
Upper Air Station and ID: Lake Charles, LA (Station #: 3937)
Meteorological Dataset: 2016
Profile Base Elevation: 7.3 meters

C. Receptor Grid

The grid modeled was sufficient in density and spatial coverage to capture representative maximum ground-level concentrations.

D. Building Wake Effects (Downwash)

Input data to Building Profile Input Program Prime (Version 04274) are consistent with the aerial photography, plot plan, and modeling report.

4. Modeling Emissions Inventory

The modeled emission point and volume source parameters and rates were generally consistent with the modeling report. The source characterizations used to represent the sources were appropriate.

The computation of the effective stack diameters for the flares is consistent with TCEQ modeling guidance.

For H_2S analyses, the modeled sigma z for volume source, Model ID FUG63A, was not consistent with the reported sigma z; however, given the low predicted concentrations, it is unlikely this inconsistency will affect the modeling results.

For the 1-hr NO_2 NAAQS analyses, emissions from six emergency generators (Model IDs PTFEG1 thru PTFEG6), two firewater pump engines (Model IDs PTFFWP and PTFFWP2), and two emergency air compressors (Model IDs PTFEAC1 and PTFEAC2) were modeled with an annual average emission rate, consistent with EPA guidance for evaluating intermittent emissions. The emergency diesel generators and the emergency air compressors will each operate no more than 50 hours per year, and the firewater pump engines will each operate no more than 100 hours per year. Since the project is located in the HGB ozone nonattainment area, the emergency engines cannot be tested between the hours of 6:00 am and 12:00 pm (Title 30 of the Texas Administrative Code Chapter § 117.2030(c)). The applicant considered this operational limitation in the determination of the annual average emission rates.

To account for abovementioned operational limitations, the modeled emission rates for six emergency generators (Model IDs PTFEG1 thru PTFEG6), two firewater pump engines (Model IDs PTFFWP and PTFFWP2), and two emergency air compressors (Model IDs PTFEAC1 and PTFEAC2) were multiplied by 0 during the hours of 6 am to 12 pm.

The applicant evaluated the start-up/shutdown emissions from the combustion turbine (EPN CT) based on EPA guidance for intermittent sources. The applicant modeled this source using an annual average emission rate for the 1-hr NO_2 NAAQS analysis. According to the applicant, the start-up/shutdown of the combustion turbine is an intermittent source: each start-up/shutdown event will last for 90 minutes or less and no more than six events per year.

Except as noted above, maximum allowable hourly emission rates were used for the short-term averaging time analyses, and annual average emission rates were used for the annual averaging time analyses.

Preliminary Determination Summary

Freeport LNG Development, L.P.
Permit Numbers 104840 and N170M1

I. Applicant

Freeport LNG Development L.P.
1500 Lamar Street
Quintana, TX 77541-8113

II. Project Location

Freeport LNG Pretreatment Facility
2363 Circle 690
Brazoria County
Freeport, Texas 77541

III. Project Description

Freeport LNG Development, L.P. (Freeport LNG) owns and operates a natural gas pretreatment plant in Quintana, Brazoria County, Texas. Freeport LNG submitted an amendment application requesting "as-built" changes. No Permit by Rule (PBR) or Standard Permit (SP) requires incorporation during this permitting action. Maintenance, startup, and shutdown (MSS) emissions are authorized under this permit.

IV. Emissions

Air Contaminant	Proposed Allowable Emission Rates (tpy)
VOC	27.79
NO_x	95.82
SO_2	61.52
CO	309.85
$PM/PM_{10}/PM_{2.5}$	80.83
H_2SO_4	4.47
H_2S	2.21
NH_3	62.77

V. Federal Applicability

The following chart illustrates the annual project emissions for each pollutant and whether this pollutant triggers PSD or Nonattainment (NA) review.

Trains 1-3

Pollutant	Project Emissions (tpy)	Major Mod Trigger (tpy)	NA Triggered Y/N	PSD Triggered Y/N
VOC	19.91	25	N	N
NO_x	44.82	25	Y	N
SO_2	37.71	250	N/A	N
CO	109.41	250	N/A	N
PM	66.45	250	N/A	N
PM_{10}	66.45	250	N/A	N
$PM_{2.5}$	66.45	250	N/A	N
H_2SO_4	2.96	250	N/A	N
H_2S	1.62	250	N/A	N

Train 4

Pollutant	Project Emissions (tpy)	Major Mod Trigger (tpy)	NA Triggered Y/N	PSD Triggered Y/N
VOC	7.39	25	N	N
NO_x	4.88	25	n	N
SO_2	22.07	250	N/A	N
CO	19.02	250	N/A	N
PM	80.26	250	N/A	N
PM_{10}	80.26	250	N/A	N
$PM_{2.5}$	80.26	250	N/A	N
H_2SO_4	1.69	250	N/A	N

Pollutant	Project Emissions (tpy)	Major Mod Trigger (tpy)	NA Triggered Y/N	PSD Triggered Y/N
H_2S	0.54	250	N/A	N

VI. Control Technology Review

New and modified sources of NO_X associated with the Trains 1-3 construction project are subject to a LAER analysis. The Train 4 construction project does not exceed NNSR major source thresholds and does not require a LAER analysis.

PTFFLARE	PTF Flare	Emissions from the Ground Flare are being updated to reflect certain maintenance activities that have become known through actual operation of these facilities and were not represented in previous applications and the proposed flare gas recovery project. The flare is a pressure assisted, multi-staged, multi-point ground flare. The flare is designed to achieve 99.5 DRE for all VOC compounds in the vapor emissions routed to it. The flare is used to control MSS activities for Trains 1-3, including the planned shutdown and startup of one train in any one year for major maintenance turnaround purposes. Freeport LNG will continue to use good combustion practices while operating the flare to limit NO_X emissions to meet LAER. NO_X emissions from the flare are based on TCEQ's factors for high-British thermal unit (Btu) streams, based on flare stream characteristics. The flare meets the design and operating requirements of the AMOC Permit AMOC71. The flare is equipped with a flow monitor and continuous emissions analyzer to ensure compliance with these requirements. Based on an updated query of the RBLC database, permits, and other regulatory requirements (such as the California Air Resources Board (CARB) determinations and California air district rules) for similar flare operations, the operating practices and compliance with applicable regulatory requirements continue to meet LAER.
FUG-TREAT	Pretreatment Train 1-3 VOC Fugitives	Freeport LNG is updating pre-flare gas recovery fugitive component counts with this project to reflect the results of ground truthing of the component counts. Emissions from piping components will be limited through the use of the 28MID LDAR requirements and an approved Optical Gas Imaging (OGI) monitoring alternative.
FUG-TRN4	Pretreatment Train 4 VOC Fugitives	
MSS-FUG1-3	Fugitives - Train 1- 3 Vessel Opening for Maintenance	LAER for the vessel opening is determined to be the following: minimizing of the number and duration of planned MSS events; MSS activities associated with large emissions from equipment containing materials with vapor pressures above 0.5 psia will be routed to the
MSS-FUG4	Fugitives - Train 4 Vessel Opening for Maintenance	

		flare; Process equipment will only be opened for inspection and maintenance after purging to the flare to minimize VOC content down to 10,000 ppmv or 10% of the lower explosive level (LEL); and Use of knockout drums to separate liquids and vapors.

VII. Air Quality Analysis

The air quality analysis (AQA) is acceptable for all review types and pollutants. The results are summarized below.

A. Minor Source NSR and Air Toxics Review

Table 1. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	13	1021
H_2SO_4	1-hr	1	50
H_2SO_4	24-hr	0.7	15
H_2S	1-hr	0.4	108

Table 2. Modeling Results for Minor NSR De Minimis

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
SO_2	1-hr	13	7.8
SO_2	3-hr	13	25
NO_2	1-hr	29	7.5
NO_2	Annual	0.3	1
CO	1-hr	130	2000
CO	8-hr	38	500

The GLCmax are the maximum predicted concentrations associated with one year of meteorological data.

The applicant relied on guidance from EPA on evaluating intermittent emissions for the 1-hr NO_2 analysis. See section 4 for additional details.

The justification for selecting the EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels was 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.

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

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. = [Background + GLCmax] (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	13	18	31	196
NO_2	1-hr	29	25	54	188

The GLCmax are the maximum predicted concentrations associated with one year of meteorological data.

Background concentrations for SO_2 were obtained from the EPA AIRS monitor 480391607 located at 901 County Rd. 792 Oyster Creek, Brazoria County. The three-year average (2019-2021) of the 99th percentile of the annual distribution of the maximum daily 1-hr concentrations was used for the 1-hr value. ADMT reviewed monitoring data from the most recent year (2022) and verified that the applicant approach will not affect the overall modeling results. This monitor is reasonable based on the proximity of the monitor to the project site (three kilometers).

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 480391607 located at 901 County Rd. 792 Oyster Creek, Brazoria County. The three-year average (2019-2021) of the 98th percentile of the annual distribution of the daily maximum 1-hr concentrations was used for the 1-hr value. ADMT reviewed monitoring data from the most recent year (2022) and verified that the applicant approach will not affect the overall modeling results. This monitor is reasonable based on the proximity of the monitor to the project site (three kilometers).

Table 4. Minor NSR Site-wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax (µg/m^3)	ESL (µg/m^3)
Mercaptans	Not found	1-hr	6	18

The GLCmax is based on generic modeling (see section 3 for more details).

1. Model Used and Modeling Techniques

[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

AERMOD (Version 21112) was used in a refined screening mode. The most recent AERMOD version (Version 23132) should be used on all future submittals.

A unitized emission rate of 1 lb/hr was used to predict a generic short-term and long-term impact for each source. The generic impact was multiplied by the proposed pollutant specific emission rates to calculate a maximum predicted concentration for each source. The maximum predicted concentration for each source was summed to get a total predicted concentration for each pollutant. The total predicted concentrations were compared to 10 percent of their respective ESLs (step 3 of the MERA guidance). All pollutants meet step 3 of the MERA except 1-hr mercaptans.

EPNs FUG-TREAT and FUG-TRN4 were divided into thirty-seven and five volume sources, respectively. A weighted unit impacts is calculated based on each volume source unit impact and proportion of total EPN emissions associated with each volume source. The calculated weighted unit impacts were used in the calculations described in the previous paragraph.

Model ID MSS_FUG represents multiple EPNs. According to the applicant, the modeled location represents the closest location of the emissions to the property line.

The applicant conducted the 1-hr and annual NO_2 NAAQS analyses using the ARM2 model option following EPA guidance.

A. Land Use

Medium roughness and elevated terrain were used in the modeling analysis. These selections are consistent with the AERSURFACE analysis, topographic maps, DEMs, and aerial photography. The selection of medium roughness is reasonable.

B. Meteorological Data

Surface Station and ID: Angleton, TX (Station #: 12976)
Upper Air Station and ID: Lake Charles, LA (Station #: 3937)
Meteorological Dataset: 2016
Profile Base Elevation: 7.3 meters

C. Receptor Grid

The grid modeled was sufficient in density and spatial coverage to capture representative maximum ground-level concentrations.

D. Building Wake Effects (Downwash)

Input data to Building Profile Input Program Prime (Version 04274) are consistent with the aerial photography, plot plan, and modeling report.

2. Modeling Emissions Inventory

The modeled emission point and volume source parameters and rates were generally consistent with the modeling report. The source characterizations used to represent the sources were appropriate.

The computation of the effective stack diameters for the flares is consistent with TCEQ modeling guidance.

For H_2S analyses, the modeled sigma z for volume source, Model ID FUG63A, was not consistent with the reported sigma z; however, given the low predicted concentrations, it is unlikely this inconsistency will affect the modeling results.

For the 1-hr NO_2 NAAQS analyses, emissions from six emergency generators (Model IDs PTFEG1 thru PTFEG6), two firewater pump engines (Model IDs PTFFWP and PTFFWP2), and two emergency air compressors (Model IDs PTFEAC1 and PTFEAC2) were modeled with an annual average emission rate, consistent with EPA guidance for evaluating intermittent emissions. The emergency diesel generators and the emergency air compressors will each operate no more than 50 hours per year, and the firewater pump engines will each operate no more than 100 hours per year. Since the project is located in the HGB ozone nonattainment area, the emergency engines cannot be tested between the hours of 6:00 am and 12:00 pm (Title 30 of the Texas Administrative Code Chapter § 117.2030(c)). The applicant considered this operational limitation in the determination of the annual average emission rates.

To account for above mentioned operational limitations, the modeled emission rates for six emergency generators (Model IDs PTFEG1 thru PTFEG6), two firewater pump engines (Model IDs PTFFWP and PTFFWP2), and two emergency air compressors (Model IDs PTFEAC1 and PTFEAC2) were multiplied by 0 during the hours of 6 am to 12 pm.

The applicant evaluated the start-up/shutdown emissions from the combustion turbine (EPN CT) based on EPA guidance for intermittent sources. The applicant modeled this source using an annual average emission rate for the 1-hr NO_2 NAAQS analysis. According to the applicant, the start-up/shutdown of the combustion turbine is an intermittent source: each start-up/shutdown event will last for 90 minutes or less and no more than six events per year.

Except as noted above, maximum allowable hourly emission rates were used for the short-term averaging time analyses, and annual average emission rates were used for the annual averaging time analyses.

VIII. Offsets

The site is located in Brazoria County, which has been designated as a serious nonattainment area for ozone. For the Houston-Galveston-Brazoria nonattainment area, designated “severe” nonattainment under the 1997 8-hour ozone standard, the retroactive analysis of this project would require permit offsets at the rate of 1:3 to 1.0 for NO_X emissions.

When issued, the permit requires that the permit holder offset the project emission increase for facilities authorized by this permit prior to the commencement of operation, through participation in the TCEQ Emission Banking and Trading (EBT) Program in accordance with the rules in 30 TAC Chapter 101, Subchapter H.

The permit holder shall use 21.5 tpy of ECs from TCEQ credit certificate numbers 2824 and 2826 to offset the 16.53 tpy NOX project emission increase at a ratio of 1.3 to 1.0.

The permit holder shall use 36.8 tpy of Mass Emission Cap and Trade (MECT) allowances available to offset the 28.29 tpy NOx project emission increase for the MECT facilities authorized by this permit at a ratio of 1.3 to 1.0.

Prior to the start of operation of the flare gas recovery project (an emissions reduction project, the permit holder shall use 45.0 tpy of NOx credits to offset the 34.6 tpy NOx project emission increase for the facilities authorized by this permit at a ratio of 1.3 to 1.0.

Prior to the commencement of operation, the permit holder is required to obtain approval from the TCEQ EBT Program for the credits being used and then submit a permit alteration or amendment request to the TCEQ Air Permits Division (and copy the TCEQ Regional Office) to identify approved credits by TCEQ credit certificate number.

IX. Alternative Site Analysis and Compliance Certification

The applicant has submitted the required demonstration relating to consideration of alternative sites and Clean Air Act compliance status for sites owned or operated by the applicant (or by any entity controlling, controlled by, or under common control with the applicant). The analysis demonstrated that the benefits of the proposed location and source configuration significantly outweigh the environmental and social costs of that location.

X. Conclusion

As described above, the applicant has demonstrated that the project meets all applicable rules, regulations and requirements of the Texas and Federal Clean Air Acts. The Executive Director’s preliminary determination is that the permits should be issued.