<u>Texas Commission on Environmental Quality</u>
INTEROFFICE MEMORANDUM

TO: Office of Chief Clerk **Date:** November 5, 2024

FROM: Contessa N. Gay
Amanda Kraynok
Staff Attorneys
Environmental Law Division

SUBJECT: Transmittal of Documents for Administrative Record

Applicant:	Corpus Christi Liquefaction, LLC
Proposed Permit Nos.:	139479 and PSDTX1496M1
Program:	Air
Docket Nos.:	TCEQ Docket No. 2024-1197-AIR SOAH Docket No. 582-25-02533

In a contested case hearing, the administrative record includes copies of the public notices relating to the permit application, as well as affidavits of public notices that are filed by the Applicant directly with the Office of the Chief Clerk (OCC). In addition, the record includes the documents listed below that are provided to the OCC by the Executive Director's staff, as required by 30 Tex. Admin. Code § 80.118.

This transmittal serves to also request that the OCC transmit the attached items and the public notice documents, including the notice of hearing, to the State Office of Administrative Hearings.

Documents included with this transmittal are indicated below:

- The final draft permit, including any special conditions or provisions
- Maximum Allowable Emission Rate Table (MAERT)
- The summary of the technical review of the permit application
- The First Air Quality Analysis Audit memoranda
- The Second Air Quality Analysis Audit memoranda
- The compliance summary of the Applicant
- The Executive Director's Preliminary Decision and the Executive Director's Decision on the Permit Application, if applicable.
- The List of Actions from the Commissioner's Integrated Database (CID)

Special Conditions

Permit Numbers 139479, PSDTX1496M1, and GHGPSDTX157M1

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

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. Affected 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):

   A. Subpart A: General Provisions.

   B. Subpart Dc: Standards of Performance for Small Industrial Commercial Institutional Steam Generation Units. **(06/19)**

   C. Subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels.

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

4. Affected 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: **(TBD)**

   A. Subpart A: General Provisions.

   B. Subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Industrial for Institutional, Commercial, and Industrial Boilers and Process Heaters

   C. Subpart ZZZZ: National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines.

Emission Standards and Operating Specifications

5. This permit authorizes nine (9) liquefied natural gas (LNG) liquefaction trains and associated support facilities. Each train contains the following equipment: a gas-fired furnace (Emission Point Nos. (EPNs) MSFURN1 through MSFURN9), a thermal oxidizer (EPNs MSTO1 through MSTO9), a standby diesel generator (EPNs MSGEN1 through MSGEN9) with diesel storage day tank (EPNs MSGENTK1 through MSGENTK9), and an amine storage tank (MSAMTNK1 through MSAMTNK9). This permit also authorizes the following support facilities: two (2) fire water pumps and diesel storage tanks (EPNs MSFWP1 and MSFWP2 and MSFWPTK1 and MSFWPTK2, respectively), three (3) multi-point ground flares (EPNs MSGFLR1 through MSGFLR3), and one fugitive emission source cap (EPN MSFUGITIVE). Emissions from flares and MSS activities are authorized under caps (EPNs GFLCAP, FLMSSCAP, MSSVACTRK) as appropriate. **(TBD)**

A. The concentration of nitrogen oxides (NO_x) from EPNs MSFURN1 through MSFURN9 shall not exceed 0.0306 pounds per Million British thermal units (lb/MMBtu) per furnace on a one-hour average, except during startup or shutdown.

B. The concentration of carbon monoxide (CO) from EPNs MSFURN1 through MSFURN9 shall not exceed 50 ppmvd, corrected to 3% O_2, per furnace on a one-hour average, except during startup and shutdown.

Emergency Engines

6. The standby generators (EPNs MSGEN1 through MSGEN9) are limited to no more than 100 hours each of non-emergency operation per calendar year. **(TBD)**

7. The firewater pump engines (EPNs MSFWP1 and MSFWP2) are limited to no more than 100 hours each of non-emergency operation per calendar year. **(06/19)**

Fuel Gas

8. Fuel for the facilities authorized by this permit is limited to the following:

   A. Thermal oxidizers and flare pilots are limited to fuel containing no more than 4 ppmv H_2S. **(06/19)**

   B. The furnaces are limited to fuel containing no more than 4 ppmv H_2S. **(06/19)**

   C. The standby generators and firewater pump engines are limited to ultra-low sulfur diesel containing no more than 15 ppm by weight sulfur.

   D. 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.

Thermal Oxidizers

9. Vents from each Acid Gas Removal Unit must be directed to the thermal oxidizers (TO). The Thermal Oxidizers (EPNs MSTO1 through MSTO9) are subject to the following requirements: **(TBD)**

   A. The Thermal Oxidizers (EPNs MSTO1 through MSTO9) shall achieve a VOC destruction efficiency greater than 99.9 percent.

   B. The thermal oxidizer firebox exit temperature shall be maintained at not less than 1400°F and exhaust oxygen concentration not less than 3 percent on a one-hour average while waste gas is being fed into the oxidizer prior to initial stack testing. After the initial stack test has been completed, the one-hour average temperature shall be equal to, or greater than the respective hourly average maintained during the most recent satisfactory stack testing required by Special Condition No. 14.

   C. The thermal oxidizer exhaust temperature shall be continuously monitored and recorded when waste gas is directed to the oxidizer. The temperature measurement device shall record the temperature readings at 15 minute intervals or less and record it at that frequency.

The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have an accuracy of the greater of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5ºC.

Quality assured (or valid) data must be generated when the thermal oxidizer is 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 thermal oxidizer operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

D. For EPNs MSTO8 and MSTO9, the oxygen analyzer used to satisfy paragraph B of this Special Condition shall continuously monitor and record oxygen concentration when waste gas is directed to the oxidizer. It shall reduce the oxygen readings to an averaging period of 1 hour or less and record it at 15 minute intervals or less.

The oxygen analyzer shall be zeroed and spanned daily and corrective action taken when the 24-hour span drift exceeds two times the amounts specified Performance Specification No. 3, 40 CFR Part 60, Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days.

The analyzer shall be quality-assured at least semiannually using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2, with the following exception: a relative accuracy test audit is not required once every four quarters (i.e., two successive semiannual CGAs may be conducted). An equivalent quality-assurance method approved by the TCEQ may also be used. Successive semiannual audits shall occur no closer than four months. Necessary corrective action shall be taken for all CGA exceedances of ±15 percent accuracy and any continuous emissions monitoring system downtime in excess of 5 percent of the incinerator operating time. These occurrences and corrective actions shall be reported to the appropriate TCEQ Regional Director on a quarterly basis. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Director.

Quality assured (or valid) data must be generated when the thermal oxidizer is 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 thermal oxidizer operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

E. During periods when the TO is not operational, vents from the Acid Gas Removal Unit shall be directed to the Low-Pressure (Acid Gas) Flare burners within each of the Multi-Point Ground Flares (MPGFs) (EPNs MSGFLR1 through MSGFLR3). **(03/23)**

Flares

10. The Low-Pressure (Acid Gas) Flare burners within each of the Multi-Point Ground Flares (EPNs MSGFLR1 through MSGFLR3), except as set forth herein, shall be designed and operated in accordance with the following requirements:**(03/23)**

A. The low-pressure flare systems shall be designed such that the combined assist natural gas and waste stream to each flare meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity under normal maintenance, startup and shutdown flow conditions. The heating value and velocity requirements shall be satisfied during operations authorized by this permit. Flare testing per 40 CFR § 60.18(f) may be requested by the appropriate regional office to demonstrate compliance with these requirements. **(03/23)**

B. The low-pressure flares shall be operated with a flame present at all times and/or have a constant pilot flame. The pilot flame shall be continuously monitored by a thermocouple, infrared, or ultraviolet monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated at a frequency in accordance with the manufacturer's specifications. **(03/23)**

C. The low-pressure flares shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours. **(03/23)**

The requirements above are not applicable during emission events. Emission events are not authorized by this permit.

D. The permit holder shall install a continuous flow monitor and composition analyzer or calorimeter that provide a record of the vent stream flow and composition (total VOC or Btu content) to the flare. The flow monitor sensor and analyzer sample points shall be installed in the vent stream as near as possible to the flare inlet such that the total vent stream to the flare is measured and analyzed. Readings shall be taken at least once every 15 minutes and the average hourly values of the flow and composition (or Btu content) shall be recorded each hour.

The monitors shall be calibrated or have a calibration check performed on an annual basis to meet the following accuracy specifications: the flow monitor shall be ±5.0%, temperature monitor shall be ±2.0% at absolute temperature, and pressure monitor shall be ±5.0 mm Hg.

If the VOC content of the vent stream is monitored for purposes of compliance with this Special Condition, calibration of the analyzer shall follow the procedures and requirements of Section 10.0 of 40 CFR Part 60, Appendix B, Performance Specification 9, as amended through October 17, 2000 (65 FR 61744), except that the multi-point calibration procedure in Section 10.1 of Performance Specification 9 shall be performed at least once every calendar quarter instead of once every month, and the mid-level calibration check procedure in Section 10.2 of Performance Specification 9 shall be performed at least once every calendar week instead of once every 24 hours. The calibration gases used for calibration procedures shall be in accordance with Section 7.1 of Performance Specification 9. Net heating value of the gas combusted in the flare shall be calculated according to the equation given in 40 CFR §60.18(f)(3) as amended through October 17, 2000 (65 FR 61744).

Notwithstanding any contrary part of this paragraph, for a gas chromatograph or mass spectrometer for compositional analysis for net heating value, the calibration error (CE) of the net heating value (NHV) measured versus the cylinder tag value NHV as the measure of agreement for daily calibration and quarterly audits in lieu of determining the compound-specific CE may be used in accordance with 40 CFR § 63.2450(e)(5)(x).

A calorimeter may be used to directly measure the heating value of the flared gas. If used, the calorimeter shall be calibrated, installed, operated, and maintained, in accordance with manufacturer recommendations, to continuously measure and record the net heating value of the gas sent to the flare, in British thermal units/standard cubic foot of the gas.

The monitors and analyzers shall operate as required by this section at least 95% of the time when the flare is operational, averaged over a rolling 12 month period. Flared gas net heating value and actual exit velocity determined in accordance with 40 CFR §§60.18(f)(3) and 60.18(f)(4) shall be recorded at least once every hour. Hourly mass emission rates shall be determined and recorded using the above readings and the emission factors used in the permit amendment application, PI-1 dated November 29, 2022 and subsequent application updates associated with TCEQ Project No. 350743. **(03/23)**

11. The high-pressure (dry flare header and wet flare header streams) burners within each of the Multi-Point Ground Flares (EPNs MSGFLR1 through MSGFLR3), except as set forth herein, shall be designed with six (6) wet vent gas high-pressure (HP) stages, nine (9) dry vent gas HP stages, associated pilots (2 per stage), and a total of 240 Zeeco MJ-4 burners with no assist air or assist steam, and shall operate in accordance with the following requirements when regulated materials are routed to each flare, to achieve at least 99% VOC, methane, and H_2S destruction and removal efficiencies (DREs). **(03/23)**

A. Operating Requirements: The net heating value of the flare vent gas combustion zone (NHVcz) must be greater than or equal to 800 British thermal units per standard cubic foot (Btu/scf), which shall be demonstrated by continuously monitoring (i.e., at least once every 15 minutes), as follows:

(1) Net Heating Values NHVcz and NHVvg. Determine the concentration of individual components and effects of assist media in the flare vent gas using the methods in 40 CFR §§ 63.670(j), (l)(1), (m)(1), and Table 12 and Table 13 of 40 CFR 63 Subpart CC (MACT CC), as applicable. Alternatively, the net heating value of the flare vent gas and hydrogen concentration may be directly monitored following the methods provided in 40 CFR §63.670(l)(2)-(3), as applicable. Different monitoring methods may be used to determine vent gas composition for different gaseous streams provided the composition or net heating value of all gas streams that contribute to the flare vent gas are determined following the options in this condition. Notwithstanding any contrary part of this paragraph, for a gas chromatograph or mass spectrometer for compositional analysis for net heating value, the calibration error (CE) of net heating value (NHV) measured versus the cylinder tag value NHV as the measure of agreement for daily calibration and quarterly audits in lieu of determining the compound-specific CE may be used in accordance with 40 CFR § 63.2450(e)(5)(x).

(2) Maximum Flare Tip Velocity (Vtip). Calculation of Vtip is not applicable to the HP MPGF burners consistent with 40 CFR § 63.1103(e)(4)(vii)(A) or § 63.2450(e)(5)(viii)(A).

(3) Flare Vent Gas Flow Rate Requirements. Install, operate, calibrate, and maintain a monitoring system capable of continuously measuring calculating, and recording the cumulative volumetric flow rates in the flare header or headers that feed the flare, including any supplemental natural gas used with the flare. The flow rate monitoring systems must comply with 40 CFR § 63.670(i), as applicable. The monitors shall meet the measurement location, accuracy, and calibration requirements of Table 13 to 40 CFR Part 63, Subpart CC.

B. Pilot Flame Requirements: Operate each stage of the pressure-assisted multi-point flare with a flame present at all times when regulated material is routed to that stage of burners. Each stage of burners that cross-lights in the pressure-assisted multi-point flare must have at least two pilots with at least one continuously lit and capable of igniting all regulated material that is routed to that stage of burners. The pilot flame(s) on each stage of burners that use cross-lighting must be continuously monitored by a thermocouple, ultraviolet beam sensor, or infrared sensor, used to detect the presence of a flame. If a stage of burners on the flare uses cross-lighting, the distance between any two burners in series on that stage shall be no more than 6 feet when measured from the center of one burner to the next burner.

C. Visible Emission Requirements: When any HP flare stage is receiving regulated materials, the MPGF shall be operated with no visible emissions except for periods not to exceed a total of 5 minutes during any 2 consecutive hours and meet 40 CFR § 63.670(c) and (h).

D. Pressure Monitor and Stage Valve Position Indicator Requirements: Install and operate pressure monitor(s) on the main flare header, as well as a valve position indicator monitoring system for each staging valve to ensure that the flares operate within the proper range of conditions as specified by the manufacturer. The pressure monitor must meet the requirements in Table 13 to 40 CFR Part 63, Subpart CC.

E. Closed Vent Capture Systems: The following requirements apply to capture systems for the Multi-Point Ground Flares.

(1) Conduct a visual, audible, and/or olfactory inspection of the capture system at least once per month to verify there are no leaking components in the capture system; or

(2) Verify the capture system is leak-free by inspecting in accordance with 40 CFR Part 60, Appendix A, Test Method 21, at least once per year. Leaks shall be indicated by an instrument reading greater than or equal to 500 ppmv above background.

(3) If there is a bypass for the control device, comply with either of the following requirements:

(a) 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

(b) Once a month, inspect the valves, verifying the position of the valves and the condition of the car seals prevent flow out the bypass.

(4) Records of the inspections required shall be maintained and if the results of any of the above inspections are not satisfactory, the permit holder shall promptly take necessary corrective action.

F. Continuous Monitoring Requirements: Follow the specifications, calibration, and maintenance procedures according to the following:

(1) At all times, all monitoring equipment must operate and be maintained in a manner consistent with 40 CFR §§ 60.11(d), 63.6(e)(1)(i), 63.671(a), and Table 13 of MACT CC with the TCEQ as the Administrator.

(2) Any monitor downtime must comply with 40 CFR §§ 63.671(a)(4) and 63.671(c). The monitors and analyzers shall operate as required by this section at least 95% of the time when the flare is operational, averaged over a rolling 12 month period.

(3) Unless otherwise specified, each measurement taken by the monitoring systems shall comply with 40 CFR §63.671(d).

G. Recordkeeping Requirements: Keep records according to 40 CFR § 63.655(i)(9)(i) through (x), except for the flare tip velocity and dilution operating limits requirements of §63.655(i)(9)(vii), and sufficient records to demonstrate compliance with this Special Condition.

H. Emission Determinations: Calculations of hourly and annual emissions to determine compliance with the MAERT limitations shall be determined and recorded using the monitoring data collected pursuant to this Special Condition applying the direct calculation method specified by §63.670(l)(5)(ii) and the emission factors and emissions methodology represented in the permit application, PI-1 dated November 29, 2022 and subsequent application updates associated with TCEQ Project No. 350743. Annual emissions shall be calculated by the end of the current month for the previous rolling 12-month period. To calculate CH_4, CO_2, and N_2O greenhouse gas emissions, use the methodology specified in Special Condition No. 31.D.

Visible Emissions

12. Opacity of emissions from any one stack, other than the flares, authorized by this permit shall not exceed five percent averaged over a six-minute period from each stack, except during planned maintenance, startup, and shutdown where it shall not exceed 15 percent. This determination shall be made by first observing for visible emissions while each facility is in operation. Observations shall be made at least 15 feet and no more than 0.25 miles from the emission point(s). Up to three emissions points may be read concurrently, provided that all three emissions points are within a 70 degree viewing sector or angle in front of the observer such that the proper sun position (at the observer's back) can be maintained for all three emission points.

    If visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60), Appendix A, Test Method 9. Instead of determining opacity as described above, the permit holder may choose to consider any observed visible emissions a violation of the opacity limit and record it as such. Observations shall be performed and recorded quarterly. If the opacity exceeds five percent or 15 percent, as applicable, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation.

Initial Determination of Compliance

13. Sampling ports and platforms shall be incorporated into the design of all thermal oxidizers and hot oil furnaces 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. **(06/19)**

14. 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 MSFURN1 through MSFURN9 and MSTO1 through MSTO9 and to determine initial compliance with all emission limits for EPNs MSFURN1 through MSFURN9 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. **(TBD)**

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 Corpus Christi 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. For EPNs MSFURN1 through MSFURN9, air contaminants and diluents to be sampled and analyzed include (but are not limited to) NO_x, O_2, CO.

C. Sampling as required by this condition shall occur within 60 days after achieving the maximum production rate at which each facility will be operated, but no later than 180 days after initial start-up of each facility. Additional sampling may be required by TCEQ or EPA.

D. The facility being sampled shall operate at maximum firing rate (i.e. 90% load +/- 10%) during stack emission testing. These conditions/parameters and any other primary operating parameters that affect the emission rate shall be monitored and recorded during the stack test. Any additional parameters shall be determined at the pretest meeting and shall be stated in the sampling report. Permit conditions and parameter limits may be waived during stack testing performed under this condition if the proposed condition/parameter range is identified in the test notice specified in paragraph A and accepted by the TCEQ Regional Office. Permit allowable emissions and emission control requirements are not waived and still apply during stack testing periods.

During subsequent operations, if the firing rate (or production rate) is greater than that recorded during the test period, stack sampling shall be performed at the new operating conditions within 120 days. This sampling may be waived by the TCEQ Air Section Manager for the region. **(06/19)**

E. Within 60 days after the completion of the testing and sampling required herein, one copy of the sampling report shall be sent to the TCEQ Corpus Christi Regional Office.

Continuous Demonstration of Compliance

15. The holder of this permit shall install, calibrate, maintain, and operate a system to continuously monitor and record the fuel consumption in the furnaces (EPNs MSFURN1 through MSFURN9). The systems shall be accurate to ± 5.0 percent of the unit's maximum flow. **(TBD)**

16. The holder of this permit shall perform stack testing in accordance with the requirements of 40 CFR Part 60, Subpart Dc. **(06/19)**

Piping, Valves, Connectors, Pumps, and Compressors – 28VHP

17. Except as may be provided for in the special conditions of this permit, the following requirements apply to all piping, valves, connectors, pumps, and compressors:

    A. These conditions shall not apply (1) where the VOC have an aggregate partial pressure or vapor pressure of less than 0.044 pound per square inch, absolute (psia) at 68ºF or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure; or (3) to components in pipeline quality natural gas or BOG service. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

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

       (1) piping and instrumentation diagram (PID);

       (2) a written or electronic database;

       (3) color coding;

       (4) a form of weatherproof identification; or

       (5) designation of exempted process unit boundaries.

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

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

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

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

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling or other such periods where flow through the valve(s) is necessary for maintenance, both valves shall be closed. If 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 24 hours. If the repair or replacement is not completed within 24 hours, the line or valve must have a cap, blind flange, plug, or second valve installed.

F. Accessible valves shall be monitored by leak checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. 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 weekly and recorded in the unit log.

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. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOCs to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each VOC to be measured.

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

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

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

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC § 115.782(c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown as calculated in accordance with 30 TAC § 115.782(c)(1)(B)(i)(I), the TCEQ Regional Manager, and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. Records of physical inspections shall be noted in the operator's log or equivalent.

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

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

Maintenance, Startup, and Shutdown

18. During planned startup, shutdown, and maintenance (MSS) for trains authorized by this permit, the maximum cumulative heat input to the common flare header, shall not exceed 8,085 MMBtu/hr in any given hour. The annual heat input from MSS activities shall not exceed 5,564,251 MMBtu. The maximum and annual heat input to the common flare header during periods of MSS will be determined using the monitoring data collected in accordance with Special Conditions No. 10 and 11. **(TBD)**

19. 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.

20. Sections of the plant handling mixed refrigerant or mixed refrigerant components 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 emptied to the pressurized refrigerant storage vessels, pumping as much liquid as practicable to the storage vessels, prior to venting to atmosphere, degassing, or draining liquid. Facilities shall be degassed using good engineering and best management practices as developed per Special Condition No. 19 to ensure air contaminants are removed from the system through the control device (EPNs MSGFLR1 through MSGFLR3) 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. **(06/19)**

B. 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 recorded (process flow diagrams [PFDs] or piping and instrumentation diagrams [P&IDs] may be used to demonstrate compliance with the requirement).

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

21. 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, sent off-site as product, 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.

Recordkeeping

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

A. A copy of this permit.

B. Permit application dated June 27, 2018 and subsequent representations submitted to the TCEQ. **(06/19)**

C. A complete copy of the testing reports and records of performance testing completed pursuant to Special Condition No. 14.

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

A. Records of continuous monitoring of fuel usage for EPNs MSFURN1; MSFURN2; MSFURN3; MSFURN4; MSFURN5; MSFURN6; MSFURN7; MSFURN8; and MSFURN9. **(TBD)**

B. For records of MSS:

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

(2) Emissions from the event.

C. Records of visible emission checks and opacity readings as required by Special Condition No. 12 and any corrective actions taken.

D. Hours of operation on a monthly and calendar year periods for the standby generators and the firewater pumps.

E. Records of thermal oxidizer temperature as required by Special Condition No. 9.

F. Records required by the monitoring program in Special Condition No. 17.

Additional GHG Specific Conditions

24. Hot oil furnaces (EPNs MSFURN1 through MSFURN9) shall adhere to the following emissions standards and operating specifications. **(TBD)**

A. The applicant represented the following design choices that will improve efficiency and decrease GHG emissions: limiting furnace fuel to natural gas or equivalent (based on CO_2 lb/MMBTU) fuel gas and Implementing vendor's recommended comprehensive inspection and maintenance program for the furnaces. **(06/19)**

B. Emissions of CO_{2e} shall not exceed the maximum allowable emission rates specified in the MAERT under all operating scenarios, including periods of authorized MSS activities.

25. The permit holder shall continuously monitor and record the average hourly fuel consumption of the furnaces with individual flow measurements being taken no less frequently than once every 15 minutes. The fuel flow meters shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. The flow meters shall be accurate to ± 5.0 percent of the unit's maximum flow. Alternatively, fuel flow meters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 are acceptable. Fuel flow meter data shall be automatically recorded with a data acquisition and handling system. The monitoring system data shall be used to demonstrate continuous compliance with the emission limits of CO_{2e} in the attached MAERT.

26. The permit holder shall continuously monitor and record (1) the average hourly flow rate to each thermal oxidizer from the vent of each Acid Gas Removal Unit and (2) the average hourly fuel consumption of each TO with individual flow measurements being taken no less frequently than once every 15 minutes. The flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. The flow meters shall be accurate to ± 5.0 percent of the unit's maximum flow. **(06/19)**

27. The permit holder shall monitor and record the operating hours of the standby generator engines and firewater pump engines.

GHG- Piping, Valves, Connectors, Pumps, Agitators, and Compressors – 28M LDAR

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

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

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

    (1) piping and instrumentation diagram (PID);

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

    (3) color coding;

    (4) a form of weatherproof identification; or

    (5) designation of exempted process unit boundaries.

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

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

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

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

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

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

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

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

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed at least quarterly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR Part 60, Appendix A. The gas analyzer shall be calibrated with methane. Replacements for leaking components shall be re-monitored within 15 days of being placed back into methane service.

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

H. Damaged or leaking valves, pump seals, compressor seals, agitator seals or connectors found to be emitting methane in excess of 10,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

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

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

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

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

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

GHG Continuous Demonstration of Compliance

30. The Facility will demonstrate compliance with CO_{2e} emissions via annual EPA GHG reporting program requirements of 40 CFR Part 98. Emission calculation methodologies and monitoring and quality assurance/quality control requirements related to GHG emissions shall adhere to the applicable requirements in 40 CFR Part 98 and in this permit. **(06/19)**

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

GHG Calculation Methodology

31. Calculations of emissions of CO_2, CH_4, and N_2O to determine compliance with the MAERT CO_{2e} emission limitation shall be calculated in the following manner by the end of the current month for the previous rolling 12-month basis.

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

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

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

    B. For each hot oil furnace (EPN MSFURN1 through MSFURN9):

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

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

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

    C. For each TO (EPNs MSTO1 through MSTO9):

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

            (a) The rolling 12-month total flow rate and CH_4 content, based on process knowledge, of acid gas sent to the TO.

            (b) A DRE of 99.9% for CH_4.

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

    D. For each flare system (EPNs MSGFLR1 through MSGFLR3): **(03/23)**

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

            (a) The rolling 12-month average CH_4 content, based on process knowledge, and total volumetric gas flow to the flare.

            (b) A DRE of 99% for methane and 100% for all other hydrocarbon compounds. **(03/23)**

        (2) To calculate N_2O emissions use

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

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

E. For the standby generators (EPNs MSGEN1 through MSGEN9) and firewater pump engines (EPNs MSFWP1 and MSFWP2):

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

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

F. For Fugitive Equipment Leaks (EPN MSFUGITIVE):

(1) Use the methodology used in the permit application.

32. Permittee shall calculate the CO_{2e} emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on November 29, 2013 (78 FR 71904).

Additional GHG Recordkeeping Requirements

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

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

B. Records for each hot oil furnace (EPNs MSFURN1 through MSFURN9) of:

(1) Monthly and rolling 12-month CO_2 and CO_{2e} emissions data in tons.

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

C. For each thermal oxidizer (EPNs MSTO1 through MSTO9), records of:

(1) One-hour average combustion chamber outlet temperature.

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

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

D. For the flares (EPN MSGFLR1 through MSGFLR3), records of:

(1) Monthly and rolling 12-month CO_{2e} emissions data in tons.

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

E. For fugitive emissions (EPN MSFUGITIVE), records required by the monitoring program in Special Condition No. 28.

F. Records of parameters used in calculations and the calculations required in Special Condition No. 31.

G. If a CEMS is selected to measure CO_2 emissions from the TOs pursuant to Special Condition No. 30, then raw data files of all CEMS data shall be kept, including calibration checks, adjustments, and maintenance performed on these systems in a permanent form suitable for inspection.

Date: TBD

Emission Sources - Maximum Allowable Emission Rates

Permit Numbers 139479 and PSDTX1496M1

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	
MSFURN1	Train 1 Hot Oil Furnace	VOC	0.41	0.92
		CO	2.94	6.83
		NOX	2.30	5.12
		PM	0.56	1.27
		PM_{10}	0.56	1.27
		$PM_{2.5}$	0.56	1.27
		SO_2	0.23	0.52
MSFURN2	Train 2 Hot Oil Furnace	VOC	0.41	0.92
		CO	2.94	6.83
		NO_X	2.30	5.12
		PM	0.56	1.27
		PM_{10}	0.56	1.27
		$PM_{2.5}$	0.56	1.27
		SO_2	0.23	0.52

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
MSFURN3	Train 3 Hot Oil Furnace	VOC	0.41	0.92
		CO	2.94	6.83
		NO_X	2.30	5.12
		PM	0.56	1.27
		PM_{10}	0.56	1.27
		$PM_{2.5}$	0.56	1.27
		SO_2	0.23	0.52
MSFURN4	Train 4 Hot Oil Furnace	VOC	0.41	0.92
		CO	2.94	6.83
		NO_X	2.30	5.12
		PM	0.56	1.27
		PM_{10}	0.56	1.27
		$PM_{2.5}$	0.56	1.27
		SO_2	0.23	0.52
MSFURN5	Train 5 Hot Oil Furnace	VOC	0.41	0.92
		CO	2.94	6.83
		NO_X	2.30	5.12
		PM	0.56	1.27
		PM_{10}	0.56	1.27
		$PM_{2.5}$	0.56	1.27
		SO_2	0.23	0.52

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lb/hr	TPY (4)
MSFURN6	Train 6 Hot Oil Furnace	VOC	0.41	0.92
		CO	2.94	6.83
		NO_X	2.30	5.12
		PM	0.56	1.27
		PM_{10}	0.56	1.27
		$PM_{2.5}$	0.56	1.27
		SO_2	0.23	0.52
MSFURN7	Train 7 Hot Oil Furnace	VOC	0.41	0.92
		CO	2.94	6.83
		NO_X	2.30	5.12
		PM	0.56	1.27
		PM_{10}	0.56	1.27
		$PM_{2.5}$	0.56	1.27
		SO_2	0.23	0.52
MSFURN8	Train 8 Hot Oil Furnace	VOC	0.41	0.92
		CO	2.94	6.83
		NO_X	2.30	5.12
		PM	0.56	1.27
		PM_{10}	0.56	1.27
		$PM_{2.5}$	0.56	1.27
		SO_2	0.23	0.52
MSFURN9	Train 9 Hot Oil Furnace	VOC	0.41	0.92
		CO	2.94	6.83

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lb/hr	TPY (4)
		NO_X	2.30	5.12
		PM	0.56	1.27
		PM_{10}	0.56	1.27
		$PM_{2.5}$	0.56	1.27
		SO_2	0.23	0.52
MSTO1	Train 1 Thermal Oxidizer	VOC	0.54	2.29
		CO	2.16	7.80
		NO_X	1.54	5.57
		PM	0.19	0.69
		PM_{10}	0.19	0.69
		$PM_{2.5}$	0.19	0.69
		H_2S	<0.01	<0.01
		SO_2	0.29	0.96
MSTO2	Train 2 Thermal Oxidizer	VOC	0.54	2.29
		CO	2.16	7.80
		NO_X	1.54	5.57
		PM	0.19	0.69
		PM_{10}	0.19	0.69
		$PM_{2.5}$	0.19	0.69
		H_2S	<0.01	<0.01
		SO_2	0.29	0.96
MSTO3	Train 3 Thermal Oxidizer	VOC	0.54	2.29
		CO	2.16	7.80

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lb/hr	TPY (4)
		NO_X	1.54	5.57
		PM	0.19	0.69
		PM_{10}	0.19	0.69
		$PM_{2.5}$	0.19	0.69
		H_2S	<0.01	<0.01
		SO_2	0.29	0.96
MSTO4	Train 4 Thermal Oxidizer	VOC	0.54	2.29
		CO	2.16	7.80
		NO_X	1.54	5.57
		PM	0.19	0.69
		PM_{10}	0.19	0.69
		$PM_{2.5}$	0.19	0.69
		H_2S	<0.01	<0.01
		SO_2	0.29	0.96
MSTO5	Train 5 Thermal Oxidizer	VOC	0.54	2.29
		CO	2.16	7.80
		NO_X	1.54	5.57
		PM	0.19	0.69
		PM_{10}	0.19	0.69
		$PM_{2.5}$	0.19	0.69
		H_2S	<0.01	<0.01
		SO_2	0.29	0.96

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lb/hr	TPY (4)
MSTO6	Train 6 Thermal Oxidizer	VOC	0.54	2.29
		CO	2.16	7.80
		NO_X	1.54	5.57
		PM	0.19	0.69
		PM_{10}	0.19	0.69
		$PM_{2.5}$	0.19	0.69
		H_2S	<0.01	<0.01
		SO_2	0.29	0.96
MSTO7	Train 7 Thermal Oxidizer	VOC	0.54	2.29
		CO	2.16	7.80
		NO_X	1.54	5.57
		PM	0.19	0.69
		PM_{10}	0.19	0.69
		$PM_{2.5}$	0.19	0.69
		H_2S	<0.01	<0.01
		SO_2	0.29	0.96
MSTO8	Train 8 Thermal Oxidizer	VOC	0.54	2.29
		CO	2.16	7.80
		NO_X	1.54	5.57
		PM	0.19	0.69
		PM_{10}	0.19	0.69
		$PM_{2.5}$	0.19	0.69
		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	
			lb/hr	TPY (4)
		SO_2	0.29	0.96
MSTO9	Train 9 Thermal Oxidizer	VOC	0.54	2.29
		CO	2.16	7.80
		NO_X	1.54	5.57
		PM	0.19	0.69
		PM_{10}	0.19	0.69
		$PM_{2.5}$	0.19	0.69
		H_2S	<0.01	<0.01
		SO_2	0.29	0.96
MSGFLR1	Midscale Ground Flare 1	VOC	5.78	-
		CO	13.23	-
		NO_X	3.32	-
		H_2S	<0.01	-
		SO_2	<0.01	-
MSGFLR2	Midscale Ground Flare 2	VOC	5.78	-
		CO	13.23	-
		NO_X	3.32	-
		H_2S	<0.01	-
		SO_2	<0.01	-
MSGFLR3	Midscale Ground Flare 3	VOC	5.78	-
		CO	13.23	-
		NO_X	3.32	-
		H_2S	<0.01	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lb/hr	TPY (4)
		SO_2	<0.01	-
GFLRCAP	Midscale Ground Flare Cap	VOC	-	24.84
		CO	-	62.58
		NO_X	-	15.69
		H_2S	-	<0.01
		SO_2	-	0.02
MSGFLR1	Midscale Ground Flare 1 (MSS)	VOC	3,516.78	-
		CO	3,138.14	-
		NO_X	1,115.70	-
		SO_2	0.55	-
		H_2S	<0.01	-
MSGFLR2	Midscale Ground Flare 2 (MSS)	VOC	3,516.78	-
		CO	3,138.14	-
		NO_X	1,115.70	-
		SO_2	0.55	-
		H_2S	<0.01	
MSGFLR3	Midscale Ground Flare 3 (MSS)	VOC	3,516.78	-
		CO	3,138.14	-
		NO_X	1,115.70	-
		SO_2	0.55	-
		H_2S	<0.01	
FLMSSCAP	Annual Flare Cap (MSS)	VOC	-	111.10
		CO	-	1,472.03

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lb/hr	TPY (4)
		NO_X	-	194.45
		SO_2	-	1.84
		H_2S	-	0.01
MSFWP1	Fire Water Pump	VOC	0.07	0.01
		CO	0.52	0.02
		NO_X	1.55	0.07
		PM	0.06	<0.01
		PM_{10}	0.06	<0.01
		$PM_{2.5}$	0.06	<0.01
		SO_2	<0.01	<0.01
MSFWP2	Fire Water Pump	VOC	0.07	0.01
		CO	0.52	0.02
		NO_X	1.55	0.07
		PM	0.06	<0.01
		PM_{10}	0.06	<0.01
		$PM_{2.5}$	0.06	<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	
			lb/hr	TPY (4)
MSGEN1	Train 1 Diesel Generator	VOC	1.86	0.08
		CO	8.49	0.39
		NO_X	15.52	0.71
		PM	0.49	0.02
		PM_{10}	0.49	0.02
		$PM_{2.5}$	0.49	0.02
		SO_2	0.02	<0.01
MSGEN2	Train 2 Diesel Generator	VOC	1.86	0.08
		CO	8.49	0.39
		NO_X	15.52	0.71
		PM	0.49	0.02
		PM_{10}	0.49	0.02
		$PM_{2.5}$	0.49	0.02
		SO_2	0.02	<0.01
MSGEN3	Train 3 Diesel Generator	VOC	1.86	0.08
		CO	8.49	0.39
		NO_X	15.52	0.71
		PM	0.49	0.02
		PM_{10}	0.49	0.02
		$PM_{2.5}$	0.49	0.02
		SO_2	0.02	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lb/hr	TPY (4)
MSGEN4	Train 4 Diesel Generator	VOC	1.86	0.08
		CO	8.49	0.39
		NO_X	15.52	0.71
		PM	0.49	0.02
		PM_{10}	0.49	0.02
		$PM_{2.5}$	0.49	0.02
		SO_2	0.02	<0.01
MSGEN5	Train 5 Diesel Generator	VOC	1.86	0.08
		CO	8.49	0.39
		NO_X	15.52	0.71
		PM	0.49	0.02
		PM_{10}	0.49	0.02
		$PM_{2.5}$	0.49	0.02
		SO_2	0.02	<0.01
MSGEN6	Train 6 Diesel Generator	VOC	1.86	0.08
		CO	8.49	0.39
		NO_X	15.52	0.71
		PM	0.49	0.02
		PM_{10}	0.49	0.02
		$PM_{2.5}$	0.49	0.02
		SO_2	0.02	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lb/hr	TPY (4)
MSGEN7	Train 7 Diesel Generator	VOC	1.86	0.08
		CO	8.49	0.39
		NO_X	15.52	0.71
		PM	0.49	0.02
		PM_{10}	0.49	0.02
		$PM_{2.5}$	0.49	0.02
		SO_2	0.02	<0.01
MSGEN8	Train 8 Diesel Generator	VOC	1.86	0.08
		CO	8.49	0.39
		NO_X	15.52	0.71
		PM	0.49	0.02
		PM_{10}	0.49	0.02
		$PM_{2.5}$	0.49	0.02
		SO_2	0.02	<0.01
MSGEN9	Train 9 Diesel Generator	VOC	1.86	0.08
		CO	8.49	0.39
		NO_X	15.52	0.71
		PM	0.49	0.02
		PM_{10}	0.49	0.02
		$PM_{2.5}$	0.49	0.02
		SO_2	0.02	<0.01
NRUGEN	NRU Diesel Generator	VOC	0.58	0.03
		CO	4.24	0.19

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lb/hr	TPY (4)
		NO_X	4.27	0.22
		PM	0.24	0.01
		PM_{10}	0.24	0.01
		$PM_{2.5}$	0.24	0.01
		SO_2	0.01	<0.01
MSFUGITIVE	Fugitive Emissions (5)	VOC	41.98	183.90
		H_2S	0.09	0.09
		Helium	0.15	0.70
MSGENTK1	Train 1 Generator Diesel Tank	VOC	0.09	<0.01
MSGENTK2	Train 2 Generator Diesel Tank	VOC	0.09	<0.01
MSGENTK3	Train 3 Generator Diesel Tank	VOC	0.09	<0.01
MSGENTK4	Train 4 Generator Diesel Tank	VOC	0.09	<0.01
MSGENTK5	Train 5 Generator Diesel Tank	VOC	0.09	<0.01
MSGENTK6	Train 6 Generator Diesel Tank	VOC	0.09	<0.01
MSGENTK7	Train 7 Generator Diesel Tank	VOC	0.09	<0.01
MSGENTK8	Train 8 Generator Diesel Tank	VOC	0.09	<0.01
MSGENTK9	Train 9 Generator Diesel Tank	VOC	0.09	<0.01
NRUGENTK	NRU Generator Diesel Tank	VOC	0.09	<0.01
MSFWPTK1	Fire Water Pump Diesel Tank	VOC	0.02	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lb/hr	TPY (4)
MSFWPTK2	Fire Water Pump Diesel Tank	VOC	0.02	<0.01
MSAMTNK1	Train 1 Amine Tank	VOC	<0.01	<0.01
MSAMTNK2	Train 2 Amine Tank	VOC	<0.01	<0.01
MSAMTNK3	Train 3 Amine Tank	VOC	<0.01	<0.01
MSAMTNK4	Train 4 Amine Tank	VOC	<0.01	<0.01
MSAMTNK5	Train 5 Amine Tank	VOC	<0.01	<0.01
MSAMTNK6	Train 6 Amine Tank	VOC	<0.01	<0.01
MSAMTNK7	Train 7 Amine Tank	VOC	<0.01	<0.01
MSAMTNK8	Train 8 Amine Tank	VOC	<0.01	<0.01
MSAMTNK9	Train 9 Amine Tank	VOC	<0.01	<0.01
MSVACTRK	Truck Loading (MSS)	VOC	<0.01	<0.01
MSANLYZ	Process Analyzers	VOC	0.05	0.22
		H_2S	<0.01	<0.01
NRU	NRU N2 Vents	Helium	223	975

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
CO - carbon monoxide
H_2S - hydrogen sulfide
MSS - maintenance, startup, and shutdown emissions
(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 MSS emissions, unless otherwise noted.

Emission Sources - Maximum Allowable Emission Rates

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

Date: TBD

Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPSDTX157M1

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

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates TPY (4)
MSFURN1	Train 1 Hot Oil Furnace	CO_2	20,969
		N_2O	0.23
		CH_4	1.13
		CO_2e	21,066
MSFURN2	Train 2 Hot Oil Furnace	CO_2	20,969
		N_2O	0.23
		CH_4	1.13
		CO_2e	21,066
MSFURN3	Train 3 Hot Oil Furnace	CO_2	20,969
		N_2O	0.23
		CH_4	1.13
		CO_2e	21,066
MSFURN4	Train 4 Hot Oil Furnace	CO_2	20,969
		N_2O	0.23
		CH_4	1.13
		CO_2e	21,066
MSFURN5	Train 5 Hot Oil Furnace	CO_2	20,969
		N_2O	0.23
		CH_4	1.13
		CO_2e	21,066
MSFURN6	Train 6 Hot Oil Furnace	CO_2	20,969
		N_2O	0.23
		CH_4	1.13
		CO_2e	21,066
MSFURN7	Train 7 Hot Oil Furnace	CO_2	20,969
		N_2O	0.23
		CH_4	1.13
		CO_2e	21,066
MSFURN8	Train 8 Hot Oil Furnace	CO_2	20,969
		N_2O	0.23
		CH_4	1.13
		CO_2e	21,066

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates TPY (4)
MSFURN9	Train 9 Hot Oil Furnace	CO_2	20,969
		N_2O	0.23
		CH_4	1.13
		CO_2e	21,066
MSTO1	Train 1 Thermal Oxidizer	CO_2	85,582
		N_2O	0.04
		CH_4	4.68
		CO_2e	85,711
MSTO2	Train 2 Thermal Oxidizer	CO_2	85,582
		N_2O	0.04
		CH_4	4.68
		CO_2e	85,711
MSTO3	Train 3 Thermal Oxidizer	CO_2	85,582
		N_2O	0.04
		CH_4	4.68
		CO_2e	85,711
MSTO4	Train 4 Thermal Oxidizer	CO_2	85,582
		N_2O	0.04
		CH_4	4.68
		CO_2e	85,711
MSTO5	Train 5 Thermal Oxidizer	CO_2	85,582
		N_2O	0.04
		CH_4	4.68
		CO_2e	85,711
MSTO6	Train 6 Thermal Oxidizer	CO_2	85,582
		N_2O	0.04
		CH_4	4.68
		CO_2e	85,711
MSTO7	Train 7 Thermal Oxidizer	CO_2	85,582
		N_2O	0.04
		CH_4	4.68
		CO_2e	85,711
MSTO8	Train 8 Thermal Oxidizer	CO_2	85,582
		N_2O	0.04
		CH_4	4.68
		CO_2e	85,711
MSTO9	Train 9 Thermal Oxidizer	CO_2	85,582

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates TPY (4)
		N_2O	0.04
		CH_4	4.68
		CO_2e	85,711
GFLRCAP	Multi-Point Ground Flare Cap	CO_2	15,336
		N_2O	0.03
		CH_4	32.22
		CO_2e	16,146
FLMSSCAP	Annual Flare Cap (MSS)	CO_2	42,4409
		N_2O	0.68
		CH_4	1,129.52
		CO_2e	452,850
MSFWP1	Firewater Pump	CO_2	12.60
		N_2O	<0.01
		CH_4	<0.01
		CO_2e	13.00
MSFWP2	Firewater Pump	CO_2	12.60
		N_2O	<0.01
		CH_4	<0.01
		CO_2e	13.00
MSGEN1	Train 1 Diesel Generator	CO_2	75.30
		N_2O	<0.01
		CH_4	<0.01
		CO_2e	76.00
MSGEN2	Train 2 Diesel Generator	CO_2	75.30
		N_2O	<0.01
		CH_4	<0.01
		CO_2e	76.00
MSGEN3	Train 3 Diesel Generator	CO_2	75.30
		N_2O	<0.01
		CH_4	<0.01
		CO_2e	76.00
MSGEN4	Train 4 Diesel Generator	CO_2	75.30
		N_2O	<0.01
		CH_4	<0.01
		CO_2e	76.00
MSGEN5	Train 5 Diesel Generator	CO_2	75.30

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
		N_2O	<0.01
		CH_4	<0.01
		CO_2e	76.00
MSGEN6	Train 6 Diesel Generator	CO_2	75.30
		N_2O	<0.01
		CH_4	<0.01
		CO_2e	76.00
MSGEN7	Train 7 Diesel Generator	CO_2	75.30
		N_2O	<0.01
		CH_4	<0.01
		CO_2e	76.00
MSGEN8	Train 8 Diesel Generator	CO_2	75.30
		N_2O	<0.01
		CH_4	<0.01
		CO_2e	76.00
MSGEN9	Train 9 Diesel Generator	CO_2	75.30
		N_2O	<0.01
		CH_4	<0.01
		CO_2e	76.00
NRUGEN	NRU Diesel Generator	CO_2	37.90
		N_2O	<0.01
		CH_4	<0.01
		CO_2e	38.00
MSFUGITIVE	Fugitive Emissions (5)	CO_2	380.40
		CH_4	642.80
		CO_2e	16,452
MSBOGMSS	BOG Compressor MSS	CH_4	0.26
		CO_2e	7.00
MSANLYZ	Process Analyzers	CO_2	0.02
		CH_4	0.20
		CO_2e	5.00
NRU	NRU N2 Vents	CH_4	17
		CO_2e	425

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) CO_2 - carbon dioxide

Emission Sources - Maximum Allowable Emission Rates

N_2O - nitrous oxide
CH_4 - methane
CO_2e - carbon dioxide equivalents, based on the following Global Warming Potentials from 40 CFR Part 98, subpart A, Table A-1, as published on November 29, 2013 (78 FR71904): CO_2 (1), CH_4 (25), and N_2O (298)

(4) Compliance with annual CO_{2e} emission limits (tons per year) is based on a 12-month rolling period. Annual emission limits includes normal and planned maintenance, startup, and shutdown (MSS) emissions. For all non-CO_{2e} GHG emissions, listed emission rates are given for informational purposes only and do not constitute an enforceable limit.

(5) Fugitive emission rates are estimates and are enforceable through compliance with the applicable special conditions and permit application representations.

Date: TBD

Permit Amendment
Source Analysis & Technical Review

Company	**Corpus Christi Liquefaction, LLC**	Permit Numbers	**139479, PSDTX1496M1, and GHGPSDTX157M1**
City	**Gregory**	Project Number	**355660**
County	**San Patricio**	Regulated Entity Number	**RN104104716**
Project Type	**Amendment**	Customer Reference Number	**CN604136374**
Project Reviewer	**Cara Hill**	Received Date	**March 30, 2023**
Site Name	**Corpus Christi Liquefaction Stage 3**		

Project Overview

Corpus Christi Liquefaction, LLC (CCL), a subsidiary of Cheniere Energy, Inc, owns and operates the liquefied natural gas (LNG) Terminal near Gregory, in San Patricio and Nueces Counties, Texas. CCL submitted the amendment to authorize the updates to representations that reflect final design of the Stage 3 Project and to authorize two additional liquefaction trains. 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
PM	19.56	17.85	-1.71	18.26
PM_{10}	19.56	17.85	-1.71	18.26
$PM_{2.5}$	19.56	17.85	-1.71	18.26
VOC	93.96	349.94	255.98	358.41
NO_X	151.42	313.10	161.68	349.35
CO	390.93	1,670.02	1,279.09	1,862.38
SO_2	12.04	15.30	3.26	15.33
H_2S	0.15	0.21	0.06	0.22
CO_{2e}	794,354.20	1,447,590.00	653,235.80	1,506,655.00

* Project increases were determined using an actual-to-potential applicability test.

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	April 6, 2023
Site rating & classification:	1.16 / Satisfactory
Company rating & classification:	1.16 / 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

00040

Public Notice Information

Requirement	
Legislator letters mailed	4/6/2023
Date 1st notice published	5/04/2023
Publication Name: *News of San Patricio*	
Pollutants: 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 greenhouse gases	
Date 1st notice Alternate Language published	5/1/2024
Publication Name (Alternate Language): *Tejano Y Grupero News*	
1st public notice tearsheet(s) received	5/11/2023
1st public notice affidavit(s) received	5/11/2023
1st public notice certification of sign posting/application availability received	7/13/2023
SB709 Notification mailed	3/11/2024
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	2
Number of meeting requests received	1
Number of hearing requests received	1
Date meeting held	
Date response to comments filed with OCC	
Date of SOAH hearing	

Federal Rules Applicability

Subject to NSPS?	**Yes**
Subparts **A, Dc, & IIII**	
Subject to NESHAP?	**No**
Subparts **N/A**	
Subject to NESHAP (MACT) for source categories?	**Yes**
Subparts **A, DDDDD, & ZZZZ**	
Nonattainment review applicability: The manufacturing plant is located in San Patricio County, which is classified as attainment or unclassified for all criteria pollutants. Nonattainment review is not applicable.	
PSD review applicability: The manufacturing plant is located in San Patricio County, which is classified as attainment or unclassified for all criteria pollutants. Project increases were determined using an actual-to-potential applicability test. Sources from the Terminal associated with the Stage 3 Expansion (Permit No. 105710, Project No. 355661) were also included in the federal applicability analysis. PSD review applies to the following pollutants for which the PTE exceeds an applicable major modification threshold: VOC, NO_X, CO, PM, PM_{10}, and $PM_{2.5}$. The PTE for SO_2 and H_2S is less than the applicable significance thresholds, and PSD requirements do not apply for these pollutants. Finally, the plant has a PTE in excess of 100 tpy (mass basis) and 75,000 tpy GHG (CO_{2e} basis) for GHG. GHG are therefore subject to regulation and PSD BACT requirements apply to GHG.	

Title V Applicability - 30 TAC Chapter 122 Rules

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-3580.

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 flow rate and BTU content or composition monitoring of the waste gas stream to the flares
- Implementation of the 28VHP and 28M LDAR programs for fugitive emissions
- Recordkeeping for storage tanks
- Hourly temperature and oxygen monitoring for the thermal oxidizers
- Recordkeeping for the heaters
- Recordkeeping for the emergency engines

Requirement
Compliance Assurance Monitoring (CAM) applicability: The site is subject to Title V permitting requirements. The flares 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. 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

CCL will operate the nine trains continuously (up to 8,760 hours per year) using electric-driven refrigeration compressors. Each of the nine trains in the liquefaction process is equipped with an Acid Gas Removal Unit (AGRU). To reduce emissions from the acid gas vent stack, sulfur emissions are controlled with sulfur removal equipment. The equipment is designed to remove the sulfur from the acid gas, which will be sent offsite for treatment and/or disposal. There are no vents directly to the atmosphere associated with the sulfur removal system. After sulfur removal, the acid gas is controlled using thermal oxidizers (EPNs MSTO-1 through MSTO-9), one per train. Acid gas can also be vented to the ground flares (EPNs MSGFLR1, MSGFLR2, and MSGFLR3) when the TOs are out of service. Nine fixed roof tanks for storage of amine (EPNs MSAMTNK1 through MSAMTNK9) will store supplies of amine.

Heavier compounds in the natural gas will be removed as condensate. The condensate will be routed to and stored in an existing internal roof floating roof tank (EPN IFRTK), authorized by Permit No. 105710, and loaded into tank trucks or pipeline for delivery to market.

Emissions related to vessel loading will be controlled by an existing marine flare (EPN MRNFLR), authorized by NSR Permit No. 105710. The marine flare will be used if a ship arrives in a condition that doesn't meet loading temperature and composition specifications required to begin loading or return displaced vapors to the LNG process.

Three ground flares (EPNs MSGFLR1, MSGFLR2, MSGFLR3), will control process emissions from the Stage 3 Project liquefaction trains. The ground flares will control emissions from continuous system purge, refrigerant compressor seal leakage, periodic maintenance, startup, and shutdown (MSS) emissions, and emissions during emergency periods.

Planned major maintenance activities of an LNG train involve shutting down the train for equipment maintenance, such as routine vessel inspection, and replacing the molecular sieve used for dehydration. Depending on the activity, one or several segments of the train may need to be depressurized and vented to the flare system. Gasses are also routed to the flare system during the startup process to cool equipment down to operating temperatures.

In addition, to maintain the performance of the refrigeration trains, more frequent planned inspection and maintenance activities will occur that require defrosting the refrigeration process (cryogenic circuits). Venting to the flare system will occur during the warming phase of a defrost as well as the subsequent drying and cooling process.

For each train, commissioning activities are required, which are vital to ensure safe, normal operation of each liquefaction train. The commissioning activities include the flaring of feed gas and refrigerants at greater than the normal operating volumes. These activities only occur before normal operations commence for each liquefaction train. Authorized MSS activities also include the overhaul of BOG compressors (EPN MSBOGMSS).

There are also nine standby emergency generators (EPNs MSGEN1 through MSGEN9) and two fire water pump engines (EPNs MSFWP1 and MSFWP2). There will be eleven fixed roof tanks to store diesel required for the generators and firewater pumps (EPNs MSGENTK1 through MSGENTK9, MSFWPTK1 and MSFWPTK2).

With the updated Stage 3 design, an End Flash Gas Unit is being added to process LNG from all nine mid-scale trains. The End Flash Gas (EFG) Unit consists primarily of a cold-box with heat exchangers and a column that will remove non-hydrocarbon contaminants from the LNG process stream as a final step before the LNG is sent to storage. The non-product stream, consisting of mostly nitrogen, generated from this process will be routed to the Nitrogen Rejection Unit (NRU). The NRU unit is designed primarily to separate nitrogen and helium from methane and return purified methane stream back to the process. The nitrogen rich stream will be vented to atmosphere and can be further refined to recover the helium to be sold on the open market.

Project Scope

CCL proposes a project to construct and operate facilities located at the Terminal. The facilities for the proposed Stage 3 project in this permit amendment application will have the capability to liquefy natural gas from the pipeline system for export as LNG. The facilities will consist of the original seven mid-scale liquefaction trains, Trains 1 through 7, plus two additional trains, Trains 8 and 9, which will liquefy natural gas into LNG. The LNG produced by the nine trains will be stored in existing LNG storage tanks within the Stage 1 and 2 Project. LNG will be exported via LNG carriers that will arrive at the CCL marine terminal.

The proposed additions and modification associated with the amendment are the following:

- Add Trains 8 and 9, identical to Trains 1 through 7.
- Add refrigerant truck unloading (fugitive equipment only).
- Add End Flash Gas Unit (EFG) (fugitive equipment only).
- Add Nitrogen Rejection Unit (NRU) (EPN NRU)
- Remove LNG Storage Diesel Generator and storage tank (EPNs MSGEN8 and MSGENTK8)
- Reduce firing rates and stack parameters for the Hot Oil Furnaces (EPN MSFURN1 through MSFURN9).
- Reduce firing rates for the Thermal Oxidizers (EPN MSTO1 through MSTO9).
- Update various process, fuel, and waste gas compositions.
- Update piping equipment counts and stream compositions for the fugitive emission calculations.
- Reduce the size of the two fire water pump engines (EPNs MSFWP1, MSFWP2). The emission factors have also been revised based on vendor data.
- Increase the size of the emergency generator fuel tanks (EPN MSGENTK1 through MSGENTK9) and fire water pump engine fuel diesel tanks (EPNs MSFWPTK1, MSFWPTK2).

Ship loading emissions from the increased loading of LNG associated with the Stage 3 Project will be controlled by the marine flare for Stages 1 & 2. Condensate storage and loading will also be accomplished with equipment associated with CCL Stage 1 & 2. The marine flare and condensate handling sources are authorized by NSR Permit No. 105710. The emissions from these sources are included for PSD applicability purposes. The additional emissions from these sources will be authorized using the appropriate separate permitting mechanism.

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

SC No.	
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.
4	Updated to applicable NESHAP standards incorporated by reference.
5	Updated to include Trains 8 and 9
6	Updated to include emergency generators for Trains 8 and 9
9	Updated to include thermal oxidizers for Trains 8 and 9, and added oxygen monitoring requirements.
14	Updated stack sampling requirements to include thermal oxidizers for Trains 8 and 9.
15	Updated to include Trains 8 and 9
18	Updated to include Trains 8 and 9
23	Updated recordkeeping to include Trains 8 and 9
24, 33	Updated greenhouse gas recordkeeping to include Trains 8 and 9

Best Available Control Technology

Control technology is consistent with PSD BACT for PSD pollutants (VOC, NO_X, CO, PM, PM_{10}, $PM_{2.5}$, and GHG) and state minor NSR BACT for SO_2 and H_2S. A control technology review was conducted for all pollutants. The controls described in this section were determined to satisfy BACT requirements based on a review of recently issued permits from Texas and other states, and consideration of the RACT/BACT/LAER Clearinghouse (RBLC) data provided by the applicant. A more detailed description of the control technology review is included in the permit file.

EPN		
MSFURN8	Train 8 Hot Oil Furnace	Emissions of NO_X are minimized through the use of low NO_X burners. The permit limits NO_X emissions to 0.03 lb/MMBtu fuel fired (HHV basis) on a 1-hr average Emissions of CO are limited to 50 ppmvd (3% O_2 basis) on a 1-hr average. SO_2 emissions are limited through use of low-sulfur fuel gas. Emissions of PM and VOC are limited through good combustion practices and the use of gaseous fuel. GHGs are limited through use of low carbon fuels and good operation and maintenance.
MSFURN9	Train 9 Hot Oil Furnace	
MSTO1	Train 1 Thermal Oxidizer	The thermal oxidizers must achieve 99.9% destruction efficiency. This is to be demonstrated through initial stack sampling and by maintaining the firebox temperature at or above the temperature demonstrated during the stack test during subsequent operations. Prior to the initial stack test, the firebox temperature must be maintained at or above 1400°F. Collateral NO_X emissions are limited to 0.06 lb/MMBtu, based on the higher heating value of the waste gas. Good combustion practices will limit CO and PM. GHGs from the thermal oxidizer will be limited through good thermal oxidizer design and best operational practices.
MSTO2	Train 2 Thermal Oxidizer	
MSTO3	Train 3 Thermal Oxidizer	
MSTO4	Train 4 Thermal Oxidizer	
MSTO5	Train 5 Thermal Oxidizer	
MSTO6	Train 6 Thermal Oxidizer	
MSTO7	Train 7 Thermal Oxidizer	
MSTO8	Train 8 Thermal Oxidizer	
MSTO9	Train 9 Thermal Oxidizer	
MSGFLR1	Midscale Ground Flare 1	All three multi-point ground flares are identical, and each have two high-pressure headers and one low-pressure header. The high-pressure headers include the “High-Pressure Dry Gas” and “High-Pressure Wet Gas” headers while the low-pressure header consists of the “Low-Pressure Acid Gas” header. Pressure-assisted (high-pressure) multi-point flares stages will achieve at least 99% destruction/removal efficiency (DRE) by adoption of a work practice standard coinciding with the operational requirements of 40 CFR Part 63, Subparts YY (Generic) and FFFF applicable to pressure-assisted multi-point flares. Subparts YY and FFFF are the National Emission Standards for Hazardous Air Pollutants for Generic Maximum Achievable Control Technology Standards and Miscellaneous Organic Chemical Manufacturing, respectively. Low-pressure stages will comply with 40 CFR 60.18 requirements and achieve at least 99% DRE for C1-C3 compounds and 98% DRE for C4+. CO and NO_X are limited through good combustion practices. SO_2 and H_2S are limited through the use of low sulfur fuel limited to 6 ppmv H_2S. GHGs are limited through the use of gaseous fuel and minimization of flaring.
MSGFLR2	Midscale Ground Flare 2	
MSGFLR3	Midscale Ground Flare 3	
MSGEN1	Train 1 Diesel Generator	The emergency generator is limited to those satisfying EPA Tier 2 requirements for VOC, PM, CO, and NO_X. The engines will fire
MSGEN2	Train 2 Diesel Generator	

EPN		
MSGEN3	Train 3 Diesel Generator	ultra-low sulfur diesel fuel, consisting of no more than 15 ppm sulfur by weight. The engines are limited to 100 hours per year of non-emergency operation. GHGs from the emergency engines will be limited through engine design and certification in accordance with standards, limited operational hours, and proper operation and maintenance.
MSGEN4	Train 4 Diesel Generator	
MSGEN5	Train 5 Diesel Generator	
MSGEN6	Train 6 Diesel Generator	
MSGEN7	Train 7 Diesel Generator	
MSGEN8	Train 8 Diesel Generator	
MSGEN9	Train 9 Diesel Generator	
NRUGEN	NRU Diesel Generator	
MSFUGITIVE	Stage 3 Fugitive Cap	Implementation of the 28VHP and 28M LDAR programs.
MSGENTK1	Train 1 Generator Diesel Tank	The diesel tanks each have a capacity less than 1,000 gallons and the vapor pressure for diesel is less than 0.5 psia. The tanks will be white, fixed-roof tanks equipped with a submerge fill mechanism.
MSGENTK2	Train 2 Generator Diesel Tank	
MSGENTK3	Train 3 Generator Diesel Tank	
MSGENTK4	Train 4 Generator Diesel Tank	
MSGENTK5	Train 5 Generator Diesel Tank	
MSGENTK6	Train 6 Generator Diesel Tank	
MSGENTK7	Train 7 Generator Diesel Tank	
MSGENTK8	Train 8 Generator Diesel Tank	
MSGENTK9	Train 9 Generator Diesel Tank	
MSANLYZ	Process Analyzers	The analyzer vent has a low concentration of VOC, H_2S, and GHG and cannot be routed to a control device. The NRU process vent is greater than 98% nitrogen and cannot be routed to a control device. This is consistent with other analyzer vents with intermittent venting frequency and low VOC and H_2S concentration in recently issued permits.
NRU	NRU N2 Vents	

Permits Incorporation

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: N/A			

Air dispersion modeling was performed by the applicant to evaluate total air emissions from the proposed project. Sources from the Terminal associated with the Stage 3 Expansion (Permit No. 105710, Project No. 355661) were also included. 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, or a violation of any PSD increment. 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 May 3, 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	

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 29, 2024

Subject: Air Quality Analysis Audit - Corpus Christi Liquefaction, LLC (RN104104716)

1. Project Identification Information

Permit Application Number: 139479
NSR Project Number: 355660
ADMT Project Number: 9069
County: San Patricio
Published Map: \\tceq4avmgisdata\GISWRK\APD\MODEL PROJECTS\9069\9069.pdf

Air Quality Analysis: Submitted by Trinity Consultants, December 2023, on behalf of Corpus Christi Liquefaction, LLC. Additional information and modeling were provided March 2024.

2. Report Summary

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

This is an as-built amendment to NSR Project 287392. This analysis is to expand the Stage 3 Project by adding two additional trains and update representations to reflect final design of the Stage 3 project. The applicant evaluated the project from the beginning and incorporated the proposed new and modified sources that are part of the Stage 3 project.

A. De Minimis Analysis

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

The justification for selecting the EPA's interim 1-hr NO_2 De Minimis level is based on the assumptions underlying EPA's development of the 1-hr NO_2 De Minimis level. As explained in EPA guidance memoranda[1], 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 NAAQS.

The $PM_{2.5}$ and ozone De Minimis levels are the EPA recommended De Minimis levels. The use of the EPA recommended De Minimis levels is sufficient to conclude that a proposed source will not cause or contribute to a violation of an ozone and $PM_{2.5}$ NAAQS or $PM_{2.5}$ PSD increments based on the analyses documented in EPA guidance and policy memoranda[2].

[1] www.tceq.texas.gov/assets/public/permitting/air/memos/guidance_1hr_no2naaqs.pdf
[2] www.tceq.texas.gov/permitting/air/modeling/epa-mod-guidance.html

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

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

Pollutant	Averaging		
PM_{10}	24-hr	1	5
PM_{10}	Annual	0.2	1
$PM_{2.5}$ (NAAQS)	24-hr	0.9	1.2
$PM_{2.5}$ (NAAQS)	Annual	0.11	0.2
$PM_{2.5}$ (Increment)	24-hr	1	1.2
$PM_{2.5}$ (Increment)	Annual	0.11	0.2
NO_2	1-hr	10	7.5
NO_2	Annual	0.8	1
CO	1-hr	168	2000
CO	8-hr	91	500

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

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

EPA intermittent guidance was relied on for 1-hr NO_2 PSD De Minimis analyses. Refer to the Modeling Emissions Inventory section for details.

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's Guideline on Air Quality Models (GAQM). Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind the MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.14 μg/m^3 and 0.01 μg/m^3, respectively. When these estimates are added to the GLCmax listed in the table above, the results are less than the De Minimis levels.

Table 2. Modeling Results for Ozone PSD De Minimis Analysis in Parts per Billion (ppb)

O_3	8-hr	0.62	1

The applicant performed an O_3 analysis as part of the PSD AQA. The applicant evaluated project emissions of O_3 precursor emissions (NO_x and VOC). For the project NO_x and VOC emissions, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. Using data associated with the Harris County source, the applicant estimated an 8-hr O_3 concentration of 0.62 ppb. When the estimates of ozone concentrations from the project emissions are added together, the results are less than the De Minimis level.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that all pollutants and averaging times are below their respective monitoring significance level.

Table 3. Modeling Results for PSD Monitoring Significance Levels

PM_{10}	24-hr	1	10
NO_2	Annual	0.8	14
CO	8-hr	91	575

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

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

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 483550034 located at 5707 Up River Rd., Corpus Christi, Nueces County. The three-year average (2020-2022) of the 98th percentile of the annual distribution of the 24-hr concentrations was used for the 24-hr value (25 $\mu g/m^3$). The three-year average (2020-2022) of the annual concentrations was used for the annual value (8.8 $\mu g/m^3$). The use of this monitor is reasonable based on the ADMT's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

Since the project has a net emissions increase of 100 tpy or more of VOC or NO_x, the applicant evaluated ambient O_3 monitoring data to satisfy the requirements for the pre-application air quality analysis.

A background concentration for ozone was obtained from the EPA AIRS monitor 483550025 located at 902 Airport Blvd., Corpus Christi, Nueces County. A three-year average (2020-2022) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis (62 ppb). The use of this monitor is reasonable based on the ADMT's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

C. National Ambient Air Quality Standard (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 1-hr NO_2 exceeds the respective de minimis concentration and requires a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 4. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

NO_2	1-hr	136	34	170	188

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

A background concentration for NO_2 was obtained from the EPA AIRS monitor 480391016 located at 109B Brazoria Hwy 332 West, Lake Jackson, Brazoria County. The three-year average (2020-2022) of the 98th percentile of the annual distribution of the maximum daily 1-hr concentrations was used for the 1-hr value. The use of the monitor is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site.

D. Increment Analysis

The De Minimis analysis modeling results indicate that all pollutants and averaging times are below the respective de minimis concentration and no further analysis is required.

E. Additional Impacts Analysis

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

The ADMT evaluated predicted concentrations from the proposed site to determine if emissions could adversely affect a Class I area. The nearest Class I area, Big Bend National Park, is located approximately 570 kilometers (km) from the proposed site.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than De Minimis levels at a distance of 6 km from the proposed sources in the direction of Big Bend National Park Class I area. Big Bend National Park is an additional 564 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than De Minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Big Bend National Park Class I area.

F. Minor Source NSR and Air Toxics Analysis

Table 5. Project-Related Modeling Results for State Property Line

SO_2	1-hr	1.6	20.4
H_2S	1-hr	0.9	2.16

Table 6. Modeling Results for Minor NSR De Minimis

SO_2	1-hr	1	7.8
SO_2	3-hr	1	25

The 1-hr SO_2 GLCmax is based on the highest five-year average of the maximum predicted concentrations determined for each receptor.

The 3-hr SO_2 GLCmax is based on the maximum predicted concentration over five years of meteorological data.

The justification for selecting the EPA's interim 1-hr SO_2 De Minimis level was based on the assumptions underlying EPA's development of the 1-hr SO_2 De Minimis level. As explained in EPA guidance memoranda[3] , the EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 1-hr SO_2 NAAQS.

Table 7. Minor NSR Site-wide Modeling Results for Health Effects

Ethylene	74-85-1	1-hr	150	Northern Property Line	1400

The GLCmax location is listed in Table 7 above.

3. Model Used and Modeling Techniques

AERMOD (Version 23132) was used in a refined screening mode.

For the health effects analysis, 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 fell out at step 3 of the MERA guidance, except 1-hr ethylene.

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

[3] www.epa.gov/sites/production/files/2015-07/documents/appwso2.pdf

A. Land Use

Surface characteristics of albedo, Bowen ratio, and surface roughness were calculated with AERSURFACE using a one-kilometer radius from the project site. The calculated surface characteristic values were used as input for the AERMET meteorological processor.

Elevated terrain was used in the modeling analysis. This selection is consistent with the topographic map, DEMs and aerial photography.

B. Meteorological Data

The applicant prepared meteorological data files for the 2018-2022 calendar years. Raw surface and upper air meteorological data were processed using AERMET (Version 23132).

Surface Station and ID: Corpus Christi, TX (Station #: 12924)
Upper Air Station and ID: Corpus Christi, TX (Station #: 12924)
Meteorological Dataset: 2020 for H_2S and health effects analyses;
2018-2022 for all other analyses
Profile Base Elevation: 13.4 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 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 the 24-hr $PM_{2.5}$ and PM_{10} De Minimis analyses, the modeled emission rates for the emergency engines (EPNs: MSGEN1-9, NRUGEN and MSFWP1-2) were based on one hour of operation per day.

The emergency generators and firewater pump engines (EPNs: MSGEN1-9, NRUGEN and MSFWP1-2) were modeled using annual average emission rates based on the expected hours of operation per year for the 1-hr NO_2 De Minimis and NAAQS analysis. According to the applicant, each engine will be tested no more than one hour per event and 100 events per year.

The applicant evaluated other on-site emergency generator and firewater pump engines (EPNs FWPUMP1–2 and SGEN1-4) based on EPA guidance for intermittent sources for the 1-hr NO_2 NAAQS analysis. Annual average emission rates were used based on each engine being tested no more than 100 hours per year.

For PM_{10} analyses, maximum allowable hourly emission rates were used for both the short-term and annual averaging time analyses.

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.

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: May 3, 2024

Subject: Second Air Quality Analysis Audit - Corpus Christi Liquefaction, LLC (RN104104716)

1. Project Identification Information

Permit Application Number: 139479
NSR Project Number: 355660
ADMT Project Number: 9149
County: San Patricio
Published Map: \\tceq4avmgisdata\GISWRK\APD\MODEL PROJECTS\9149\9149.pdf

Air Quality Analysis: Submitted by Trinity Consultants, April 2024, on behalf of Corpus Christi Liquefaction, LLC. Additional information and modeling were provided April 2024.

This is the second modeling audit for this NSR Project, and the second audit is conducted to review revised modeling conducted due to changes to the emission rates for the thermal oxidizers (EPNs MSTO1 – MSTO9). This memo represents a complete summary and supersedes the previous audit memo dated March 29, 2024 (WCC content ID 6995402).

2. Report Summary

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

This is an as-built amendment to NSR Project 287392. This analysis is to expand the Stage 3 Project by adding two additional trains and update representations to reflect final design of the Stage 3 project. The applicant evaluated the project from the beginning and incorporated the proposed new and modified sources that are part of the Stage 3 project.

A. De Minimis Analysis

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

The justification for selecting the EPA's interim 1-hr NO_2 De Minimis level is based on the assumptions underlying EPA's development of the 1-hr NO_2 De Minimis level. As explained in EPA guidance memoranda[1], 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 NAAQS.

The $PM_{2.5}$ and ozone De Minimis levels are the EPA recommended De Minimis levels. The use of the EPA recommended De Minimis levels is sufficient to conclude that a proposed

[1] www.tceq.texas.gov/assets/public/permitting/air/memos/guidance_1hr_no2naaqs.pdf

source will not cause or contribute to a violation of an ozone and $PM_{2.5}$ NAAQS or $PM_{2.5}$ PSD increments based on the analyses documented in EPA guidance and policy memoranda[2].

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

Table 1. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter (µg/m³)

Pollutant	Averaging		
PM_{10}	24-hr	1	5
PM_{10}	Annual	0.2	1
$PM_{2.5}$ (NAAQS)	24-hr	0.9	1.2
$PM_{2.5}$ (NAAQS)	Annual	0.11	0.2
$PM_{2.5}$ (Increment)	24-hr	1	1.2
$PM_{2.5}$ (Increment)	Annual	0.12	0.2
NO_2	1-hr	10	7.5
NO_2	Annual	0.8	1
CO	1-hr	168	2000
CO	8-hr	91	500

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

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

EPA intermittent guidance was relied on for 1-hr NO_2 PSD De Minimis analyses. Refer to the Modeling Emissions Inventory section for details.

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's Guideline on Air Quality Models (GAQM). Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind the MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations

[2] www.tceq.texas.gov/permitting/air/modeling/epa-mod-guidance.html

of 0.131 µg/m^3 and 0.008 µg/m^3, respectively. When these estimates are added to the GLCmax listed in the Table 1 above, the results are less than the De Minimis levels.

The revised annual $PM_{2.5}$ SIL of 0.13 µg/m^3 will be effective May 6, 2024. When the annual secondary $PM_{2.5}$ concentration of 0.008 µg/m^3 is added to the GLCmax listed in the Table 1 above, the results are less than the revised De Minimis levels.

Table 2. Modeling Results for Ozone PSD De Minimis Analysis in Parts per Billion (ppb)

Pollutant	Averaging		
O_3	8-hr	0.64	1

The applicant performed an O_3 analysis as part of the PSD AQA. The applicant evaluated project emissions of O_3 precursor emissions (NO_x and VOC). For the project NO_x and VOC emissions, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. Using data associated with the Harris County source, the applicant estimated an 8-hr O_3 concentration of 0.64 ppb. When the estimates of ozone concentrations from the project emissions are added together, the results are less than the De Minimis level.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that all pollutants and averaging times are below their respective monitoring significance level.

Table 3. Modeling Results for PSD Monitoring Significance Levels

Pollutant			
PM_{10}	24-hr	1	10
NO_2	Annual	0.8	14
CO	8-hr	91	575

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

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

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 483550034 located at 5707 Up River Rd., Corpus Christi, Nueces County. The three-year average (2021-2023) of the 98th percentile of the annual distribution of the 24-hr concentrations was used for the 24-hr value (23 µg/m^3). The three-year average (2021-2023) of the annual concentrations was used for the annual value (8.8 µg/m^3). The use of this monitor is reasonable based on the ADMT's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

Since the project has a net emissions increase of 100 tpy or more of VOC or NO_X, the applicant evaluated ambient O_3 monitoring data to satisfy the requirements for the pre-application air quality analysis.

A background concentration for ozone was obtained from the EPA AIRS monitor 483550025 located at 902 Airport Blvd., Corpus Christi, Nueces County. A three-year average (2020-2022) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis (62 ppb). The applicant did not consider 2023 monitoring data, however, ADMT reviewed 2023 monitoring data and verified the applicant's approach will not affect the overall analysis conclusion. The use of this monitor is reasonable based on the ADMT's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

C. National Ambient Air Quality Standard (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 1-hr NO_2 exceeds the respective de minimis concentration and requires a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 4. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. =	
NO_2	1-hr	136	34	170	188

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

A background concentration for NO_2 was obtained from the EPA AIRS monitor 480391016 located at 109B Brazoria Hwy 332 West, Lake Jackson, Brazoria County. The three-year average (2021-2023) of the 98th percentile of the annual distribution of the maximum daily 1-hr concentrations was used for the 1-hr value. Monitoring data from the third quarter of 2023 is incomplete. ADMT performed the EPA substitution test and validated the use of 2023 monitoring data. The use of the monitor is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site.

D. Increment Analysis

The De Minimis analysis modeling results indicate that all pollutants and averaging times are below the respective de minimis concentration and no further analysis is required.

E. Additional Impacts Analysis

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

The ADMT evaluated predicted concentrations from the proposed site to determine if emissions could adversely affect a Class I area. The nearest Class I area, Big Bend National Park, is located approximately 570 kilometers (km) from the proposed site.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than De Minimis levels at a distance of 6 km from the proposed sources in the direction of Big Bend National Park Class I area. Big Bend National Park is an additional 564 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than De Minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Big Bend National Park Class I area.

F. Minor Source NSR and Air Toxics Analysis

Table 5. Project-Related Modeling Results for State Property Line

Pollutant			
SO_2	1-hr	1.6	20.4
H_2S	1-hr	0.9	2.16

Table 6. Modeling Results for Minor NSR De Minimis

Pollutant			
SO_2	1-hr	1	7.8
SO_2	3-hr	1	25

The 1-hr SO_2 GLCmax is based on the highest five-year average of the maximum predicted concentrations determined for each receptor.

The 3-hr SO_2 GLCmax is based on the maximum predicted concentration over five years of meteorological data.

The justification for selecting the EPA's interim 1-hr SO_2 De Minimis level was based on the assumptions underlying EPA's development of the 1-hr SO_2 De Minimis level. As explained in EPA guidance memoranda[3] , the EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 1-hr SO_2 NAAQS.

Table 7. Minor NSR Site-wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging			
Ethylene	74-85-1	1-hr	150	Northern Property Line	1400

The GLCmax location is listed in Table 7 above.

3. Model Used and Modeling Techniques

AERMOD (Version 23132) was used in a refined screening mode.

[3] www.epa.gov/sites/production/files/2015-07/documents/appwso2.pdf

For the health effects analysis, 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 fell out at step 3 of the MERA guidance, except 1-hr ethylene.

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

A. Land Use

Surface characteristics of albedo, Bowen ratio, and surface roughness were calculated with AERSURFACE using a one-kilometer radius from the project site. The calculated surface characteristic values were used as input for the AERMET meteorological processor.

Elevated terrain was used in the modeling analysis. This selection is consistent with the topographic map, DEMs and aerial photography.

B. Meteorological Data

The applicant prepared meteorological data files for the 2018-2022 calendar years. Raw surface and upper air meteorological data were processed using AERMET (Version 23132).

Surface Station and ID: Corpus Christi, TX (Station #: 12924)
Upper Air Station and ID: Corpus Christi, TX (Station #: 12924)
Meteorological Dataset: 2020 for H_2S and health effects analyses;
2018-2022 for all other analyses
Profile Base Elevation: 13.4 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 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 the 24-hr $PM_{2.5}$ and PM_{10} De Minimis analyses, the modeled emission rates for the emergency engines (EPNs: MSGEN1-9, NRUGEN and MSFWP1-2) were based on one hour of operation per day.

The emergency generators and firewater pump engines (EPNs: MSGEN1-9, NRUGEN and MSFWP1-2) were modeled using annual average emission rates based on the expected hours of operation per year for the 1-hr NO_2 De Minimis and NAAQS analyses. According to the applicant, each engine will be tested no more than one hour per event and 100 events per year.

The applicant evaluated other on-site emergency generator and firewater pump engines (EPNs FWPUMP1–2 and SGEN1-4) based on EPA guidance for intermittent sources for the 1-hr NO_2 NAAQS analysis. Annual average emission rates were used based on each engine being tested no more than 100 hours per year.

For PM_{10} analyses, maximum allowable hourly emission rates were used for both the short-term and annual averaging time analyses.

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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Compliance History Report

Compliance History Report for CN604136374, RN104104716, Rating Year 2023 which includes Compliance History (CH) components from September 1, 2018, through August 31, 2023.

Customer, Respondent, or Owner/Operator:	CN604136374, Corpus Christi Liquefaction, LLC	**Classification:**	SATISFACTORY	**Rating:**	11.38
Regulated Entity:	RN104104716, CORPUS CHRISTI LIQUEFACTION	**Classification:**	SATISFACTORY	**Rating:**	11.38
Complexity Points:	16	**Repeat Violator:**	NO		
CH Group:	14 - Other				
Location:	622 HWY 35 GREGORY, TX 78359, SAN PATRICIO COUNTY				
TCEQ Region:	REGION 14 - CORPUS CHRISTI				

ID Number(s):

AIR OPERATING PERMITS PERMIT 3580
AIR OPERATING PERMITS ACCOUNT NUMBER SDA005E
AIR OPERATING PERMITS PERMIT 4592
PUBLIC WATER SYSTEM/SUPPLY REGISTRATION 2050079
AIR NEW SOURCE PERMITS PERMIT 105710
AIR NEW SOURCE PERMITS EPA PERMIT GHGPSDTX123
AIR NEW SOURCE PERMITS EPA PERMIT GHGPSDTX157
AIR NEW SOURCE PERMITS EPA PERMIT PSDTX1496
AIR NEW SOURCE PERMITS EPA PERMIT PSDTX1306
AIR NEW SOURCE PERMITS PERMIT 139479
AIR NEW SOURCE PERMITS REGISTRATION 167968
AIR NEW SOURCE PERMITS EPA PERMIT PSDTX1306M1
AIR NEW SOURCE PERMITS EPA PERMIT GHGPSDTX123M1
AIR NEW SOURCE PERMITS EPA PERMIT PSDTX1496M1
AIR NEW SOURCE PERMITS EPA PERMIT PSDTX1306M2
AIR NEW SOURCE PERMITS EPA PERMIT GHGPSDTX157M1
AIR NEW SOURCE PERMITS AFS NUM 4840900071
WASTEWATER PERMIT WQ0005367000
WASTEWATER EPA ID TX0134002
AIR EMISSIONS INVENTORY ACCOUNT NUMBER SDA005E
TAX RELIEF ID NUMBER 24569
TAX RELIEF ID NUMBER 23975
TAX RELIEF ID NUMBER 24545
TAX RELIEF ID NUMBER 23760
TAX RELIEF ID NUMBER 23498
TAX RELIEF ID NUMBER 24547
TAX RELIEF ID NUMBER 23495
TAX RELIEF ID NUMBER 23912
TAX RELIEF ID NUMBER 23911
TAX RELIEF ID NUMBER 23494
TAX RELIEF ID NUMBER 23761
TAX RELIEF ID NUMBER 23762
TAX RELIEF ID NUMBER 23763
TAX RELIEF ID NUMBER 22908
TAX RELIEF ID NUMBER 23057
TAX RELIEF ID NUMBER 22931
TAX RELIEF ID NUMBER 22923
TAX RELIEF ID NUMBER 22919
TAX RELIEF ID NUMBER 22989
TAX RELIEF ID NUMBER 22590
TAX RELIEF ID NUMBER 22916
TAX RELIEF ID NUMBER 22988
TAX RELIEF ID NUMBER 22907
TAX RELIEF ID NUMBER 22929
TAX RELIEF ID NUMBER 22930
TAX RELIEF ID NUMBER 22913
TAX RELIEF ID NUMBER 22909
TAX RELIEF ID NUMBER 23056
TAX RELIEF ID NUMBER 22920
TAX RELIEF ID NUMBER 22589
TAX RELIEF ID NUMBER 22924
TAX RELIEF ID NUMBER 22910
TAX RELIEF ID NUMBER 23297
TAX RELIEF ID NUMBER 22917
TAX RELIEF ID NUMBER 22918
TAX RELIEF ID NUMBER 22925
TAX RELIEF ID NUMBER 22927
TAX RELIEF ID NUMBER 22912
TAX RELIEF ID NUMBER 22922
TAX RELIEF ID NUMBER 22906
TAX RELIEF ID NUMBER 22926
TAX RELIEF ID NUMBER 22928
TAX RELIEF ID NUMBER 22921
TAX RELIEF ID NUMBER 23058
TAX RELIEF ID NUMBER 22610
TAX RELIEF ID NUMBER 22915
TAX RELIEF ID NUMBER 22914
TAX RELIEF ID NUMBER 25868
TAX RELIEF ID NUMBER 25867
TAX RELIEF ID NUMBER 24021
TAX RELIEF ID NUMBER 24546
TAX RELIEF ID NUMBER 24570
TAX RELIEF ID NUMBER 27064
TAX RELIEF ID NUMBER 27063

Compliance History Period: September 01, 2018 to August 31, 2023 **Rating Year:** 2023 **Rating Date:** 09/01/2023

Date Compliance History Report Prepared: November 04, 2024

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

Component Period Selected: March 30, 2018 to March 30, 2023

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: 03/13/2023 ADMINORDER 2021-1033-AIR-E (1660 Order-Agreed Order With Denial)

Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 116, SubChapter B 116.115(b)(2)(F)
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: SC 1 PERMIT
STC 9 OP

Description: Failure to comply with the MAER for the Condensate Tank (EPN IFRTK1). Specifically, the Respondent exceeded the VOC MAER of 0.43 ton per year ("tpy") based on a 12-month rolling period for the 12-month period ending on October 2020 for the Condensate Tank, EPN IFRTK1, resulting in approximately 0.11 ton of unauthorized VOC emissions.

Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
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: SC 10 PERMIT
STC 9 OP

Description: Failure to comply with the minimum outlet temperature for the thermal oxidizer (EPN TO-1). Specifically, the Respondent established the minimum outlet temperature for the Thermal Oxidizer to be 1,740 °F on an hourly average basis when waste gas is directed to the Thermal Oxidizer, but the outlet temperature was below 1,740 °F for a total of 24 hours from January 1, 2020 to April 19, 2020 and a total of seven hours from September 6, 2020 to October 29, 2020.

Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(1)
30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 115, SubChapter B 115.112(c)(1)
30 TAC Chapter 116, SubChapter B 116.115(c)
30 TAC Chapter 122, SubChapter B 122.143(4)
40 CFR Chapter 60, SubChapter C, PT 60, SubPT Kb 60.112b(a)(3)
5C THSC Chapter 382 382.085(b)

Rqmt Prov: SC 2B PERMIT
STC 1A OP
STC 4 OP
STC 8 OP

Description: Failure to replace carbon canister after exceeding the VOC concentration limit. Specifically, the carbon canisters of the carbon absorption system for the Wastewater Tank exceeded the VOC concentration limit of 100 parts per million on January 6, 2020 and on September 9, 2020, but the carbon canisters were not replaced in a timely manner.

Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 116, SubChapter B 116.115(b)(2)(F)
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: SC 1 PERMIT
STC 9 OP

Description: Failure to comply with the MAERs for the Marine Flare ([EPN] MRNFLR). Specifically, the Respondent exceeded the nitrogen oxides ("NOx") MAER of 106.23 pounds per hour ("lbs/hr") by 23.33 lbs/hr for one hour on January 22, 2020 and the VOC MAER of 7.85 lbs/hr by a range from 0.16 lb/hr to 37.47 lbs/hr for a total of 17 hours on May 2, 2020, October 14, 2020, November 17, 2020, and November 22, 2020 for the Marine Flare, EPN MRNFLR, resulting in 23.33 pounds ("lbs") of unauthorized VOC emissions.

Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 116, SubChapter B 116.115(b)(2)(F)
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: GC 14 PERMIT
GC 8 PERMIT
SC 1 PERMIT
STC 9 OP

Description: Failure to comply with the MAER for Wet/Dry Gas Flare 2 (EPN WTDYFLR2). Specifically, the Respondent exceeded the CO MAER of 106.20 lbs/hr by 35.80 lbs/hr and 50.80 lbs/hr for two hours on January 24, 2020 for the Wet/Dry Gas Flare 2, EPN WTDYFLR2, resulting in 86.60 lbs of unauthorized CO emissions.

Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 116, SubChapter B 116.115(b)(2)(F)
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: SC 1 PERMIT
STC 9 OP

Description: Failure to comply with the MAER for Wet/Dry Gas Flare 1 (EPN WTDYFLR1). Specifically, the Respondent exceeded the VOC MAER of 5.21 lbs/hr by a range from 0.37 lb/hr to 29.8 lbs/hr for four hours on February 20, 2020 and two hours on October 23, 2020 for the Wet/Dry Gas Flare 1, EPN WTDYFLR1, resulting in 48.80 lbs of unauthorized VOC emissions.

See addendum for information regarding federal actions.

B. Criminal convictions:

N/A

C. Chronic excessive emissions events:

N/A

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

Item 1	April 11, 2018	(1779539)
Item 2	June 13, 2018	(1467137)
Item 3	July 26, 2018	(1779559)
Item 5	October 24, 2018	(1779569)
Item 7	January 24, 2019	(1779585)
Item 8	February 19, 2019	(1538368)
Item 9	April 23, 2019	(1779540)
Item 10	July 23, 2019	(1779555)
Item 11	August 14, 2019	(1578932)
Item 12	August 27, 2019	(1578942)
Item 14	October 23, 2019	(1779570)
Item 15	November 25, 2019	(1610691)
Item 16	November 26, 2019	(1605788)

Item 17	January 22, 2020	(1779586)
Item 18	January 28, 2020	(1603853)
Item 19	February 11, 2020	(1617950)
Item 20	March 06, 2020	(1632574)
Item 21	April 20, 2020	(1779541)
Item 22	May 14, 2020	(1645407)
Item 23	May 21, 2020	(1646900)
Item 24	June 24, 2020	(1652577)
Item 25	July 23, 2020	(1779556)
Item 26	August 13, 2020	(1622660)
Item 27	October 06, 2020	(1679110)
Item 28	October 09, 2020	(1622659)
Item 29	October 23, 2020	(1678317)
Item 30	October 26, 2020	(1779576)
Item 31	October 29, 2020	(1685520)
Item 32	November 13, 2020	(1659743)
Item 33	November 17, 2020	(1690485)
Item 34	December 17, 2020	(1697140)
Item 35	December 23, 2020	(1697125)
Item 36	January 19, 2021	(1779592)
Item 37	January 25, 2021	(1692337)
Item 38	April 15, 2021	(1706110)
Item 40	April 22, 2021	(1779546)
Item 41	May 13, 2021	(1706400)
Item 42	June 28, 2021	(1711699)
Item 43	June 30, 2021	(1711751)
Item 44	July 22, 2021	(1779557)
Item 45	October 19, 2021	(1779572)
Item 46	November 17, 2021	(1785844)
Item 48	January 18, 2022	(1800730)
Item 49	February 15, 2022	(1808558)
Item 50	March 16, 2022	(1815616)
Item 51	April 13, 2022	(1822172)
Item 52	May 12, 2022	(1831072)
Item 53	June 08, 2022	(1837322)
Item 54	June 16, 2022	(1819375)
Item 56	July 18, 2022	(1844508)
Item 58	September 12, 2022	(1858449)
Item 59	October 11, 2022	(1864790)
Item 60	November 16, 2022	(1871698)
Item 61	November 23, 2022	(1855793)
Item 62	December 14, 2022	(1877562)
Item 63	January 17, 2023	(1884365)
Item 65	February 14, 2023	(1892177)
Item 66	March 08, 2023	(1900755)

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.

1 Date: 06/17/2022 (1805519)

Self Report? NO Classification: Moderate

Citation:
30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 116, SubChapter B 116.115(c)
30 TAC Chapter 122, SubChapter B 122.143(4)
40 CFR Chapter 60, SubChapter C, PT 60, SubPT IIII 60.4211(a)
5C THSC Chapter 382 382.085(b)
PSDTX1306M1, Special Condition No. 2C PERMIT
Special Term and Condition No. 1A OP
Special Term and Condition No. 9 OP

Description: Failure to comply with applicable emissions requirements provided by 40

Code of Federal Regulations (CFR) Part 60 Subpart IIII for non-emergency engines.

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 116, SubChapter B 116.115(c)
30 TAC Chapter 122, SubChapter B 122.143(4)
40 CFR Chapter 60, SubChapter C, PT 60, SubPT A 60.8(a)
40 CFR Chapter 60, SubChapter C, PT 60, SubPT KKKK 60.4400(a)
5C THSC Chapter 382 382.085(b)
PSDTX1306M1, Special Condition No. 20E PERMIT
Special Condition No. 11D PERMIT
Special Term and Condition No. 1A OP
Special Term and Condition No. 6B OP
Special Term and Condition No. 9 OP

Description: Failure to conduct an Initial Demonstration of Compliance Stack Test by the required deadline.

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 122, SubChapter B 122.143(4)
30 TAC Chapter 122, SubChapter B 122.145(2)(A)
5C THSC Chapter 382 382.085(b)
General Terms and Conditions OP

Description: Failure to report all instances of deviations on previous deviation reports.

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
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)
PSDTX1306M1, Special Condition No. 23I PERMIT
Special Condition No. 16I PERMIT
Special Term and Condition No. 9 OP

Description: Failure to repair a leak within fifteen calendar days from the date of detection.

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 116, SubChapter B 116.115(b)(2)(F)
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)
PSDTX1306M1, Special Condition No. 1 PERMIT
Special Term and Condition No. 9 OP

Description: Failure to comply with permitted emission rates for refrigeration compressor turbine 16 (EPN TRB16).

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 116, SubChapter B 116.115(b)(2)(F)
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)
PSDTX1306M1, Special Condition No. 1 PERMIT
Special Term and Condition No. 9 OP

Description: Failure to comply with permitted emission rates for thermal oxidizer 1 (EPN TO-1).

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 116, SubChapter B 116.115(b)(2)(F)
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)
PSDTX1306M1, Special Condition No. 1 PERMIT
Special Term and Condition No. 9 OP

Description: Failure to comply with permitted emission rates for thermal oxidizer 2 (EPN TO-2).

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 116, SubChapter B 116.115(b)(2)(F)
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)
PSDTX1306M1, Special Condition No. 1 PERMIT
Special Term and Condition No. 9 OP

Description: Failure to comply with permitted emission rates for thermal oxidizer 3 (EPN TO-3).

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
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)
PSDTX1306M1, Special Condition No. 7A PERMIT
Special Term and Condition No. 9 OP

Description: Failure to limit hydrogen sulfide (H2S) content of fuel utilized by thermal oxidizers and flare pilots to four (4) parts per million volume (ppmv).

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
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)
PSDTX1306M1, Special Condition No. 23F PERMIT
Special Term and Condition No. 9 OP

Description: Failure to perform quarterly LDAR monitoring of all components.

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 116, SubChapter B 116.115(b)(2)(F)
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)
PSDTX1306M1, Special Condition No. 1 PERMIT
Special Term and Condition No. 9 OP

Description: Failure to comply with permitted emissions rates for marine flare (EPN MRNFLR).

F. Environmental audits:

Notice of Intent Date: 09/13/2018 (1519121)

Disclosure Date: 07/30/2019

Viol. Classification: Minor

Citation: 30 TAC Chapter 116, SubChapter B 116.115(c)

Rqmt Prov: PERMIT 28M

Description: Failure to conduct quarterly monitoring on the LNG rundown line from Tank A to marine loading.

Viol. Classification: Minor

Citation: 30 TAC Chapter 116, SubChapter B 116.115(c)

Rqmt Prov: PERMIT SC 18.H

Description: Failure to complete an initial repair attempt within 5 days of discovery.

Viol. Classification: Minor

Citation: 30 TAC Chapter 116, SubChapter B 116.115(c)

Rqmt Prov: PERMIT SC 18.I

Description: Failure to make a final repair attempt within 15 days of discovery.

Viol. Classification: Minor

Citation: 30 TAC Chapter 116, SubChapter B 116.115(c)

Rqmt Prov: PERMIT SC 18.H

Description: Failure to complete an initial repair attempt within five days of discovery.

Viol. Classification: Minor

Citation: 30 TAC Chapter 116, SubChapter B 116.115(c)

Rqmt Prov: PERMIT SC 18.I

Description: Failure to conduct a final repair attempt with 15 days of discovery.

Viol. Classification: Minor

Citation: 30 TAC Chapter 116, SubChapter B 116.115(c)

Rqmt Prov: PERMIT SC 18.H

Description: Failure to conduct an initial repair attempt within 5 days of discovery.

Viol. Classification: Minor

Citation: 30 TAC Chapter 116, SubChapter B 116.115(c)

Rqmt Prov: PERMIT SC 18.l

Description: Failure to conduct a final repair attempt within 15 days of discovery.

Viol. Classification: Moderate

Citation: 30 TAC Chapter 116, SubChapter B 116.115(c)

Rqmt Prov: PERMIT SC 18.D

Description: Failure to maintain a list identifying difficult and unsafe to monitor components as required by NSR 105710.

Viol. Classification: Minor

Citation: 30 TAC Chapter 116, SubChapter B 116.115(c)

Rqmt Prov: PERMIT 18.F

Description: Failure to monitor certain LDAR components within 90 days of initial in-service date.

Viol. Classification: Moderate

Citation: 30 TAC Chapter 122, SubChapter C 122.221(a)

Description: Failure to obtain Title V authorization for "as-built" changes that were operated before Title V Permit O3580 was revised.

Viol. Classification: Moderate

Citation: 30 TAC Chapter 122, SubChapter C 122.210(a)

Description: Failure to operate a fuel dispensing facility authorized by a permit by rule greater than 12 months and prior to submitted Title V O3580 application.

Notice of Intent Date: 06/25/2020 (1664219)

No DOV Associated

Notice of Intent Date: 10/23/2020 (1691239)

No DOV Associated

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

Preliminary Determination Summary

Corpus Christi Liquefaction, LLC
Permit Numbers 139479, PSDTX1496M1, and GHGPSDTX157M1

I. Applicant

Corpus Christi Liquefaction LLC
700 Milam Street, Suite 1900
Houston, TX 77002-2835

II. Project Location

Corpus Christi Liquefaction Stage 3
622 Highway 35
San Patricio County
Gregory, Texas 78359

III. Project Description

Corpus Christi Liquefaction, LLC (CCL), a subsidiary of Cheniere Energy, Inc, owns and operates the liquefied natural gas (LNG) Terminal near Gregory, in San Patricio and Nueces Counties, Texas. CCL submitted the amendment to authorize the updates to representations that reflect final design of the Stage 3 Project and to authorize two additional liquefaction trains. 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	349.94
NO_x	313.10
SO_2	15.30
CO	1,670.02
$PM/PM_{10}/PM_{2.5}$	17.85/17.85/17.85
H_2S	0.21
CO2 Equivalents (CO2e)	1,447,590.00

CO2e - carbon dioxide equivalents based on global warming potentials of CH4 = 25, N2O = 298, SF6=22,800.

V. Federal Applicability

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

Pollutant				
VOC	358.41	25 for NA 40 for PSD	N/A	Y
NO_x	349.35	25 for NA 40 for PSD	N/A	Y
SO_2	15.33	40	N/A	N
CO	1,862.38	100	N/A	Y
PM	18.26	25	N/A	Y
PM_{10}	18.26	15	N/A	Y
$PM_{2.5}$	18.26	10	N/A	Y
H_2SO_4	N/A	7	N/A	N/A
H_2S	0.22	10	N/A	N

The proposed project triggers PSD review for non-GHG NSR regulated pollutants. As shown in the table below, because the project increase is more than 75,000 tpy of CO_{2e}, PSD review is triggered for GHG emissions.

Pollutant			
CO_{2e}	1,506,655.00	75,000	Y

VI. Control Technology Review

Control technology is consistent with PSD BACT for PSD pollutants (VOC, NO_X, CO, PM, PM_{10}, $PM_{2.5}$, and GHG) and state minor NSR BACT for SO_2 and H_2S. A control technology review was conducted for all pollutants. The controls described in this section were determined to satisfy BACT requirements based on a review of recently issued permits from Texas and other states, and consideration of the RACT/BACT/LAER Clearinghouse (RBLC) data provided by the applicant. A more detailed description of the control technology review is included in the permit file.

Hot Oil Furnaces
Emissions of NO_X are minimized through the use of low NO_X burners. The permit limits NO_X emissions to 0.03 lb/MMBtu fuel fired (HHV basis) on a 1-hr average. Emissions of CO are limited to 50 ppmvd (3% O_2 basis) on a 1-hr average. Emissions of PM and VOC are limited through good combustion practices and the use of gaseous fuel. GHGs are limited through use of low carbon fuels and good operation and maintenance.

Thermal Oxidizers
The thermal oxidizers must achieve 99.9% destruction efficiency. This is to be demonstrated through initial stack sampling and by maintaining the firebox temperature at or above the temperature demonstrated during the stack test during subsequent operations. Prior to the initial stack test, the firebox temperature must be maintained at or above 1400°F. Collateral NO_X emissions are limited to 0.06 lb/MMBtu, based on the higher heating value of the waste gas. Good combustion practices will limit CO and PM. GHGs from the thermal oxidizer will be limited through good thermal oxidizer design and best operational practices.

Ground Flares
Pressure-assisted (high-pressure) multi-point flares stages will achieve at least 99% destruction/removal efficiency (DRE) by adoption of a work practice standard coinciding with the operational requirements of 40 CFR Part 63, Subparts YY (Generic) and FFFF applicable to pressure-assisted multi-point flares. Subparts YY and FFFF are the National Emission Standards for Hazardous Air Pollutants for Generic Maximum Achievable Control Technology Standards and Miscellaneous Organic Chemical Manufacturing, respectively. Low-pressure stages will comply with 40 CFR 60.18 requirements and achieve at least 99% DRE for C1-C3 compounds and 98% DRE for C4+. CO and NO_X are limited through good combustion practices. GHGs are limited through the use of gaseous fuel and minimization of flaring.

Emergency Generators
The emergency generator is limited to those satisfying EPA Tier 2 requirements for VOC, PM, CO, and NO_X. The engines are limited to 100 hours per year of non-emergency operation. GHGs from the emergency engines will be limited through engine design and certification in accordance with standards, limited operational hours, and proper operation and maintenance.

Fugitives
Implementation of the 28VHP and 28M LDAR programs for the VOC and GHG emissions.

Fixed Roof Tanks
The diesel tanks each have a capacity less than 1,000 gallons and the vapor pressure for diesel is less than 0.5 psia. The tanks will be white, fixed-roof tanks equipped with a submerge fill mechanism.

Uncontrolled Vents
The analyzer vent has a low concentration of VOC and GHG and cannot be routed to a control device. The NRU process vent is greater than 98% nitrogen and cannot be routed to a control device. This is consistent with other analyzer vents with intermittent venting frequency and low VOC and H_2S concentration in recently issued permits.

VII. Air Quality Analysis

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

This is an as-built amendment to NSR Project 287392. This analysis is to expand the Stage 3 Project by adding two additional trains and update representations to reflect final design of the Stage 3 project. The applicant evaluated the project from the beginning and incorporated the proposed new and modified sources that are part of the Stage 3 project.

A. De Minimis Analysis

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

The justification for selecting the EPA's interim 1-hr NO_2 De Minimis level is based on the assumptions underlying EPA's development of the 1-hr NO_2 De Minimis level. As explained in EPA guidance memoranda[1], 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 NAAQS.

The $PM_{2.5}$ and ozone De Minimis levels are the EPA recommended De Minimis levels. The use of the EPA recommended De Minimis levels is sufficient to conclude that a proposed source will not cause or contribute to a violation of an ozone and $PM_{2.5}$ NAAQS or $PM_{2.5}$ PSD increments based on the analyses documented in EPA guidance and policy memoranda[2].

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

Table 1. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter (µg/m³)

Pollutant	Averaging		
PM_{10}	24-hr	1	5
PM_{10}	Annual	0.2	1
$PM_{2.5}$ (NAAQS)	24-hr	0.9	1.2
$PM_{2.5}$ (NAAQS)	Annual	0.11	0.2
$PM_{2.5}$ (Increment)	24-hr	1	1.2
$PM_{2.5}$ (Increment)	Annual	0.12	0.2
NO_2	1-hr	10	7.5
NO_2	Annual	0.8	1
CO	1-hr	168	2000
CO	8-hr	91	500

[1] www.tceq.texas.gov/assets/public/permitting/air/memos/guidance_1hr_no2naaqs.pdf
[2] www.tceq.texas.gov/permitting/air/modeling/epa-mod-guidance.html

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

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

EPA intermittent guidance was relied on for 1-hr NO_2 PSD De Minimis analyses. Refer to the Modeling Emissions Inventory section for details.

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's Guideline on Air Quality Models (GAQM). Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind the MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.131 µg/m^3 and 0.008 µg/m^3, respectively. When these estimates are added to the GLCmax listed in the Table 1 above, the results are less than the De Minimis levels.

The revised annual $PM_{2.5}$ SIL of 0.13 µg/m^3 will be effective May 6, 2024. When the annual secondary $PM_{2.5}$ concentration of 0.008 µg/m^3 is added to the GLCmax listed in the Table 1 above, the results are less than the revised De Minimis levels.

Table 2. Modeling Results for Ozone PSD De Minimis Analysis in Parts per Billion (ppb)

Pollutant	Averaging		
O_3	8-hr	0.64	1

The applicant performed an O_3 analysis as part of the PSD AQA. The applicant evaluated project emissions of O_3 precursor emissions (NO_x and VOC). For the project NO_x and VOC emissions, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. Using data associated with the Harris County source, the applicant estimated an 8-hr O_3 concentration of 0.64 ppb. When the estimates of ozone concentrations from the project emissions are added together, the results are less than the De Minimis level.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that all pollutants and averaging times are below their respective monitoring significance level.

Table 3. Modeling Results for PSD Monitoring Significance Levels

Pollutant			
PM_{10}	24-hr	1	10
NO_2	Annual	0.8	14

Pollutant			
CO	8-hr	91	575

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

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

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 483550034 located at 5707 Up River Rd., Corpus Christi, Nueces County. The three-year average (2021-2023) of the 98th percentile of the annual distribution of the 24-hr concentrations was used for the 24-hr value (23 μg/m^3). The three-year average (2021-2023) of the annual concentrations was used for the annual value (8.8 μg/m^3). The use of this monitor is reasonable based on the ADMT's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

Since the project has a net emissions increase of 100 tpy or more of VOC or NO_X, the applicant evaluated ambient O_3 monitoring data to satisfy the requirements for the pre-application air quality analysis.

A background concentration for ozone was obtained from the EPA AIRS monitor 483550025 located at 902 Airport Blvd., Corpus Christi, Nueces County. A three-year average (2020-2022) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis (62 ppb). The applicant did not consider 2023 monitoring data, however, ADMT reviewed 2023 monitoring data and verified the applicant's approach will not affect the overall analysis conclusion. The use of this monitor is reasonable based on the ADMT's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 1-hr NO_2 exceeds the respective de minimis concentration and requires a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 4. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (μg/m^3)	Background (μg/m^3)	Total Conc. =	
NO_2	1-hr	136	34	170	188

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

A background concentration for NO_2 was obtained from the EPA AIRS monitor 480391016 located at 109B Brazoria Hwy 332 West, Lake Jackson, Brazoria County. The three-year average (2021-2023) of the 98th percentile of the annual distribution of the maximum daily

1-hr concentrations was used for the 1-hr value. Monitoring data from the third quarter of 2023 is incomplete. ADMT performed the EPA substitution test and validated the use of 2023 monitoring data. The use of the monitor is reasonable based on the applicant's review of land use, county population, county emissions, and a quantitative review of emissions surrounding the area of the monitor site relative to the project site.

D. Increment Analysis

The De Minimis analysis modeling results indicate that all pollutants and averaging times are below the respective de minimis concentration and no further analysis is required.

E. Additional Impacts Analysis

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

The ADMT evaluated predicted concentrations from the proposed site to determine if emissions could adversely affect a Class I area. The nearest Class I area, Big Bend National Park, is located approximately 570 kilometers (km) from the proposed site.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than De Minimis levels at a distance of 6 km from the proposed sources in the direction of Big Bend National Park Class I area. Big Bend National Park is an additional 564 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than De Minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Big Bend National Park Class I area.

F. Minor Source NSR and Air Toxics Review

Table 5. Project-Related Modeling Results for State Property Line

SO_2	1-hr	1.6	20.4
H_2S	1-hr	0.9	2.16

Table 6. Modeling Results for Minor NSR De Minimis

SO_2	1-hr	1	7.8
SO_2	3-hr	1	25

The 1-hr SO_2 GLCmax is based on the highest five-year average of the maximum predicted concentrations determined for each receptor.

The 3-hr SO_2 GLCmax is based on the maximum predicted concentration over five years of meteorological data.

The justification for selecting the EPA's interim 1-hr SO_2 De Minimis level was based on the assumptions underlying EPA's development of the 1-hr SO_2 De Minimis level. As explained in EPA guidance memoranda[3] , the EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 1-hr SO_2 NAAQS.

Table 7. Minor NSR Site-wide Modeling Results for Health Effects

Ethylene	74-85-1	1-hr	150	Northern Property Line	1400

The GLCmax location is listed in Table 7 above.

G. Greenhouse Gases

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

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

VIII. Conclusion

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.

[3] www.epa.gov/sites/production/files/2015-07/documents/appwso2.pdf

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Activity Action List:

Date	Document Type	Action
12/05/2024	SOAH HEARING	SCHEDULED
10/22/2024	NOTICE OF SOAH HEARING	MAILED
10/21/2024	NOTICE OF SOAH HEARING	MAILED
09/26/2024	RESPONSE TO COMMENTS	MAILED
09/19/2024	RESPONSE TO COMMENTS	RECEIVED
07/25/2024	DIRECT REFERRAL - APPLIC	RECEIVED
07/25/2024	TCEQ DOCKET NUMBER	ISSUED
07/25/2024	TCEQ DOCKET NUMBER	REQUESTED
06/27/2024	ALTERNATIVE LANGUAGE VERIFICATION FORM	RECEIVED
06/27/2024	COMMENT PERIOD	END
06/27/2024	AVAILABILITY VERIFICATIO	RECEIVED
06/20/2024	PUBLIC MEETING	HELD
06/20/2024	PUBLIC MEETING	SCHEDULED
05/29/2024	ALTERNATIVE LANGUAGE AFFIDAVIT	RECEIVED
05/29/2024	AFFIDAVIT - NAPD	RECEIVED

05/29/2024	NEWSPAPER TEARSHEET	RECEIVED
05/29/2024	ALTERNATIVE LANGUAGE TEARSHEET	RECEIVED
05/17/2024	NOTICE OF PUBLIC MEETING	MAILED
05/16/2024	NOTICE - PRELIM DECISION	PUBLISHED
05/16/2024	NOTICE OF PUBLIC MEETING	RECEIVED
05/15/2024	ALTERNATIVE LANGUAGE NOTICE	PUBLISHED
05/13/2024	CONFIRMATION	RECEIVED
05/10/2024	NOTICE - PRELIM DECISION	MAILED
05/08/2024	NOTICE - PRELIM DECISION	RECEIVED
05/06/2024	PUBLIC MEETING	ED APPROVE
03/11/2024	LETTER	SENT TO
07/13/2023	ALTERNATIVE LANGUAGE VERIFICATION FORM	RECEIVED
07/13/2023	AVAILABILITY VERIFICATIO	RECEIVED
07/05/2023	COMMENT PERIOD	END
05/11/2023	ALTERNATIVE LANGUAGE TEARSHEET	RECEIVED
05/11/2023	AFFIDAVIT - NORI	RECEIVED
05/11/2023	NEWSPAPER TEARSHEET	RECEIVED
05/11/2023	ALTERNATIVE LANGUAGE AFFIDAVIT	RECEIVED
05/04/2023	NOTICE OF RECEIPT/INTENT	PUBLISHED
05/01/2023	ALTERNATIVE LANGUAGE NOTICE	PUBLISHED
04/07/2023	NOTICE OF RECEIPT/INTENT	MAILED
04/06/2023	NOTICE OF RECEIPT/INTENT	RECEIVED
04/06/2023	ADMIN REVIEW	COMPLETE

03/30/2023	APPLICATION	RECEIVED

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Last Modified 2023-05-17 - Production v3.2.1