Texas Commission on Environmental Quality
INTEROFFICE MEMORANDUM

TO: Office of Chief Clerk **DATE:** October 30, 2023

FROM: Contessa N. Gay
Staff Attorney
Environmental Law Division

SUBJECT: Backup Documents Filed for Consideration of Hearing Requests at Agenda

Applicant: Corpus Christi Liquefaction, LLC
Permit Nos.: 105710, GHGPSDTX123M1, PSDTX1306M1
Program: Air
Docket No.: TCEQ Docket No. 2023-1474-AIR

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

- The final draft of the permit special conditions
- The Emission Sources – Maximum Allowable Emission Rates
- The Air Quality Analysis Modeling Audit (First Audit)
- The Air Quality Analysis Modeling Audit (Second Audit)
- The Compliance History Report
- The Permit Amendment Source Analysis & Technical Review

Special Conditions

Permit Numbers 105710 and PSDTX1306M1

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.

Federal Applicability

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

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

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

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

   A. Subpart A: General Provisions.

   B. Subpart EEEE: National Emission Standards for HAPS: Organic Liquids Distribution (Non-Gasoline).

   C. Subpart YYYY: National Emission Standards for HAPS for Stationary Combustion Turbines.

   D. Subpart ZZZZ: National Emission Standard for HAPS for Stationary Reciprocating Internal Combustion Engines.

Emission Standards and Operating Specifications

4. This permit authorizes eighteen GE LM2500+G4 DLE natural gas fired combustion turbines. **(2/15)**

   A. The concentration of nitrogen oxides (NOx) from EPNs: TRB1 through TRB18 shall not exceed 25 parts per million by volume dry (ppmvd) per turbine corrected to 15 percent oxygen (O2) on a four-hour rolling average for routine operation, except during startup or shutdown, and a one-hour basis for stack emissions testing. **(2/15)**

   B. The concentration of carbon monoxide (CO) from EPNs: EPNs: TRB1 through TRB18 shall not exceed 29 ppmvd per turbine corrected to 15 percent O_2, on a one-hour average, except during startup and shutdown.

   C. Planned startup or shutdown of the turbines is limited to no more than 1 hour per turbine per event.

      (1) Startup is defined as beginning when fuel is fired in the combustor from a previously unfired state and ending when turbine loads exceed 50%.

(2) Shutdown is defined as beginning when turbine load drops below 50% and ending when fuel ceases to be fired.

5. The standby generators (EPNs: GEN1 through GEN 4) are limited to no more than 100 hours each of non-emergency operation per 12-month period. **(7/18)**

6. The firewater pump engines (EPNs: FWPUMP1 and FWPUMP2) are limited to no more than 100 hours each of non-emergency operation per 12-month period. **(7/18)**

7. 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 by volume H_2S on a 1-hour averaging period.

B. The H_2S concentration of the fuel gas for thermal oxidizers and flare pilots shall be continuously monitored by an in-line analyzer and recorded at least once every 15 minutes. The analyzer shall be calibrated to the manufacturer’s recommended frequency and specifications. **(XX/22)**

C. The turbines are limited to fuel containing no more than 4 ppmv by volume H_2S. Records shall be maintained of the applicable pipeline H_2S tariff requirements.

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

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

8. The condensate storage tank (EPN: IFRTK1) must meet the following conditions:

A. An internal floating deck or “roof” or equivalent control shall be installed. The floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof: (1) a liquid-mounted seal, (2) two continuous seals mounted one above the other, or (3) a mechanical shoe seal.

B. The permit holder shall perform the visual inspections and seal gap measurements as specified in Title 40 Code of Federal Regulations § 60.113b (40 CFR § 60.113b) Testing and Procedures (as amended at 54 FR 32973, August 11, 1989) to verify fitting and seal integrity. Records shall be maintained of the dates seals were inspected and seal gap measurements made, results of inspections and measurements made (including raw data), and actions taken to correct any deficiencies noted.

C. The floating roof design shall incorporate sufficient flotation to conform to the requirements of API Code 650 dated November 1, 1998 except that an internal floating cover need not be designed to meet rainfall support requirements and the materials of construction may be steel or other materials.

D. Uninsulated tank exterior surfaces exposed to the sun shall be white or aluminum. The storage tank must be equipped with permanent submerged fill pipes.

E. The maximum tank withdrawal rate is limited to 18,000 gallons per hour when condensate is transferred to pipeline and 9,000 gallons per hour when loaded to trucks. Truck loading of condensate must be submerged fill. **(7/18)**

F. The permit holder must maintain a record of total tank throughput for the previous month and the past consecutive 12-month period.

9. Fixed roof tanks uninsulated exterior surfaces exposed to the sun shall be white or aluminum. Storage tank EPN GDFTK2 must be equipped with permanent submerged fill pipes. **(11/20)**

10. VOC emissions from the spent scavenger tank (EPN TK1902) shall be controlled through carbon canister. The carbon canister shall be routinely monitored per EPA Method 21 (40 CFR 60, Appendix A) and replaced before breakthrough occurs. **(11/20)**

11. Each condensate tank truck shall be leak checked and certified annually in accordance with 40 CFR § 60.502(e).

The permit holder shall not allow a tank truck to be filled unless it has passed a leak-tight test within the past year as evidenced by a certificate which shows the date the tank truck last passed the leak-tight test required by this condition and the identification number of the tank truck. **(11/20)**

12. Atmospheric truck loading of condensate shall be controlled by a vapor combustion unit. Vapor Combustors shall be designed and operated in accordance with the following requirements:

The vapor combustor unit (VCU) shall achieve 99% control of the waste gas directed to it. This shall be ensured by maintaining the temperature in, or immediately downstream of, the combustion chamber above 1400 degrees Fahrenheit prior to the initial stack test performed in accordance with this Special Condition. Following the completion of that stack test, the six-minute average temperature shall be maintained above the minimum one-hour average temperature maintained during the last satisfactory stack test.

The temperature measurement device shall reduce the temperature readings to an averaging period of 6 minutes or less and record it at that frequency. The temperature monitor shall be installed, calibrated or have a calibration check performed at least annually, and maintained according to the manufacturer's specifications. The device shall have an accuracy of the greater of ± 2 percent of the temperature being measured expressed in degrees Celsius or ± 2.5ºC.

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

The vapor combustor shall be operated with no visible emissions and have a constant pilot flame during all times waste gas could be directed to it. The pilot flame shall be continuously monitored by a thermocouple or an infrared 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 or have a calibration check performed at a frequency in accordance with, the manufacturer’s specifications. (Calibration check means, at a minimum, using a second device or method to verify that the monitor is accurate as specified in the permit.

Vapor Combustor Stack Sampling

The vapor combustor shall be stack sampled to determine a minimum temperature that achieves 99% DRE. This minimum temperature shall be the parameter that compliance is based on. **(7/18)**

13. Vents from each Acid Gas Removal Unit must be directed to the thermal oxidizers (TO) or the flare. The TO combustion chamber outlet temperatures for EPNs: TO-1, TO-2, and TO-3 shall be continuously monitored when waste gas is directed to the TO. The minimum outlet temperature shall be 1400 degrees Fahrenheit on an hourly average basis, until a minimum operating temperature is established by the testing required in Special Condition No. 20, when waste gas is directed to the TO. The outlet temperature must be recorded at least four times an hour (once per quarter of the hour) when waste gas is directed to the TO. The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have accuracy the greater of 1 percent of the temperature being measured or 4.5 degrees Fahrenheit. **(7/18)**

14. The flare systems (EPNs: WTDYFLR1, WTDYFLR2, and MRNFLR), except as set forth herein, shall be designed and operated in accordance with the following requirements: **(XX/22)**

    A. The 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 and maintenance 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. EPN: MRNFLR shall not be subject to the minimum heating value requirement of 40 CFR § 60.18 during the process of venting inert gases from ships.

    B. The wet/dry flares (EPNs: WTDYFLR1 and WTDYFLR2) 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 or an infrared 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.

    C. The marine flare, EPN: MRNFLR, shall be operated with a flame present at all times when liquefied natural gas carriers (LNGCs) are connected to the vapor transfer arm. During all times when EPN: MRNFLR is in use, the pilot flame shall be continuously monitored by a thermocouple or an infrared 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.

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

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

    E. The permit holder shall install a continuous flow monitor and composition analyzer or continuous flow monitor and 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, except during periods when the flare is offline or the monitor is undergoing calibrations, and the average hourly values of the flow, composition and heating value shall be recorded each hour.

F. 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.

G. If the VOC content of the vent stream is monitored for purposes of compliance with Special Condition 14.E, 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).

H. 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.

I. 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 determined in accordance with 40 CFR §§60.18(f)(3) 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 application workbook received December 27, 2019.

J. The following requirements apply to the capture system for each flare:

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

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

(3) The control device shall not have a bypass.

(4) A bypass does not include authorized analyzer vents, highpoint bleeder vents, low point drains, or rupture discs upstream of pressure relief valves if the pressure between the disc and relief valve is monitored and recorded at least weekly. A deviation shall be reported if the monitoring or inspections indicate bypass of the control device when it is required to be in service.

K. 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.

L. The flare systems shall comply with Paragraphs E through K of this condition no later than 18 months after issuance of the permit amendment associated with NSR Project No. 327940.

During the 18-month interim period, data from the existing flare flow monitors shall be used in conjunction with stream compositions and calculation methods represented in the permit application (PI-1 dated April 19, 2021, as revised) to demonstrate compliance with the short-term (lb/hr) and annual (tpy) emission limits specified by the MAERT.

M. Flow and composition data required by Special Condition No. 14.E for the flares (EPNs WTDYFLR1, WTDFLR2, and MRNFLR) shall be used to calculate a mass emission rate for each pollutant expressed in lb/hr. The only exceptions to this requirement are when a flare is off line or during periods of monitor calibration or other authorized monitor downtime.

N. Flow and composition data required by Special Condition No. 14.E for the flares shall be used to calculate a monthly mass emission rate for each pollutant expressed in tons per month. Operations of units and processes controlled by the flares shall be limited such that the combined flared waste gas emissions do not exceed the MAERT limits for the Wet/Dry Flare Cap (Normal Operations, EPNs WTDFLR1 and WTDFLR2) or the Marine Flare (EPN MRNFLR) on a rolling 12-month basis. All flare emission calculations shall be performed using TCEQ approved emission factors.

15. When conditioning a marine vessel to accept liquefied natural gas (LNG), any associated emissions from the LNGC must be routed to EPN: MRNFLR so that EPN: MRNFLR can act as a vent stack during purging of any inert gases. When loading LNGCs, boil off gas that meets the quality and temperature specification must be returned to the process. **(7/18)**

16. No more than two marine vessels may be conditioned or vented to the marine flare (EPN MRNFLR) at any given time. **(XX/22)**

17. During required emergency shutdown (ESD) testing at the upstream Sinton Compressor Facility, boil-off gas (BOG) from the LNG tanks that cannot be routed back to the process shall be vented to the marine flare (EPN MRNFLR). During the ESD testing, all LNG loading of marine vessels shall commence shutdown and remain inactive during the duration of the ESD testing process. Records of the date, time, and duration of ESD testing events and associated cessation of marine loading shall be maintained to demonstrate compliance with this condition. **(XX/22)**

18. 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

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

20. 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: TRB1 through TRB18 and TO-1 through TO-3 and to determine initial compliance with all emission limits for EPNs: TRB1 through TRB18 established in this permit. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods to be determined during the pretest meeting.

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

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

    A. The TCEQ 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: TRB1 through TRB18, air contaminants and diluents to be sampled and analyzed include (but are not limited to) NOx, O_2, CO, volatile organic compounds (VOC), and SO_2.

Fuel sampling using the methods and procedures of 40 CFR § 60.4415. For SO_2, the exemptions from emissions testing and fuel monitoring in 40 CFR § 60.4365(b) will apply.

C. Each turbine shall be tested at or above 90% of maximum load operations. Each tested turbine load shall be identified in the sampling report. The permit holder shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with emission standards found in 40 CFR Part 60, Subpart KKKK.

D. For EPNs: TO-1 through TO-3, a VOC destruction efficiency of at least 99.9% or a VOC outlet concentration of 10 ppmvd or less at 3 percent oxygen on a one-hour average must be demonstrated. The minimum operating temperature shall be the one-hour average temperature at which compliance with the above was demonstrated.

E. 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.

F. 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

21. The holder of this permit shall install, calibrate, maintain, and operate a system to continuously monitor and record the fuel consumption in the turbines (EPNs: TRB1 through TRB18). The system shall be accurate to ± 5.0% of the unit's maximum flow rate and calibrated according to the manufacturer's instructions **(2/15)**

22. After every hot section (gas generator) change-out, the holder of this permit shall perform the testing described in Special Condition No. 20 for that turbine(s) again.

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

23. 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 an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

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

24. 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.

25. Sections of the plant handling ethylene or propane 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. 24 to ensure air contaminants are removed from the system through the control device (EPNs: WTDYFLR1 and WTDYFLR2) 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. **(11/20)**

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.

D. Propane depressurization shall be limited to 56 hours per year, on a rolling 12-month basis. **(XX/22)**

26. All contents from process equipment or storage tanks must be removed to the maximum extent possible practicable prior to opening equipment to commence degassing and maintenance. Liquid

and solid removal must be directed to covered containment, recycled, or disposed of properly. If it is necessary to drain liquid into an open pan or the sump, the liquid must be covered and transferred to a covered vessel within one hour of being drained.

Recordkeeping

27. 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 August 31, 2017, and subsequent representations submitted to the TCEQ.

    C. A complete copy of the testing reports and records of performance testing completed pursuant to Special Condition No. 20.

28. 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: **(XX/22)**

    A. Records of hourly fuel consumption of EPNs: TRB1 through TRB18.

    B. For records of MSS:

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

        (2) Emissions from the event.

    C. Records of condensate load-out kept on a monthly basis.

    D. Records of H_2S concentration in the fuel gas used as required by Special Condition No. 7B.

    E. Records of flare waste gas flow data, waste gas composition or heating value data, and capture system inspections as required by Special Condition No. 14.

    F. Records of short-term mass emission rates at the flares as required by Special Condition No. 14.M.

    G. Records of visible emission checks and opacity readings as required by Special Condition No. 18 and any corrective actions taken.

    H. Hours of operation on a monthly and 12-month period for the standby generators and the firewater pumps.

    I. Records of thermal oxidizer temperature as required by Special Condition No. 13.

    J. Records required by the monitoring program in Special Condition No. 23.

Other Authorizations

29. The following sources and/or activities are authorized under a Permit by Rule (PBR) by Title 30 Texas Administrative Code Chapter 106 (30 TAC Chapter 106). This list is not intended to be all inclusive and can be altered without modifications to this permit.

Authorization	**Source or Activity**
PBR 106.261	Facilities (Emission Limitations) - Fugitives
PBR 106.262	Facilities (Emission and Distance Limitations) - Fugitives
PBR 106.263	Planned Maintenance, Startup and Shutdown
PBR 106.355	Pipeline Metering, Purging, and Maintenance
PBR 106.359	Planned Maintenance, Startup, and Shutdown (MSS) at Oil and Gas Handling and Production Facilities - Abrasive Blasting
PBR 106.472	Diesel Storage Tanks - EPNs DSLTK6, DSLTK7, DSLTK8
PBR 106.473	Gasoline Storage Tank - EPN GDFTK3
PBR 106.478	Diesel Storage Tank - EPN DSLTK5
PBR 106.511	Portable and Emergency Engines and Turbines - EPNs GEN5, GEN7
PBR 106.512	Stationary Engines and Turbines - EPNs GEN6, GEN8, GEN9, GEN11, GEN12

Special Conditions

Permit Number GHGPSDTX123M1

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.

Emission Standards and Operating Specifications

2. This permit authorizes eighteen (18) GE LM2500+G4 DLE natural gas fired combustion turbines.

   A. Permittee shall follow manufacturer’s emission-related written instructions for maintenance activities including prescribed maintenance intervals to assure good combustion. Compressors shall be inspected and maintained according to a written maintenance plan.

   B. Planned startup or shutdown of the turbines is limited to no more than 1 hour per turbine per event.

      (1) Startup is defined as beginning when fuel is fired in the combustor from a previously unfired state and ending when turbine loads exceed 50%.

      (2) Shutdown is defined as beginning when turbine load drops below 50% and ending when fuel ceases to be fired.

3. The standby generators (EPNs: GEN1 through GEN4) are limited to no more than 100 hours each of non-emergency operation per 12-month period. Each generator shall be equipped with a non-resettable elapsed run time meter.

4. The firewater pump engines (EPNs: FWPUMP1 through FWPUMP2) are limited to no more than 100 hours each of non-emergency operation per 12-month period. Each engine shall be equipped with a non-resettable elapsed run time meter.

5. 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 by volume H_2S on a 1-hour averaging period.

   B. The H_2S concentration of the fuel gas for thermal oxidizers and flare pilots shall be continuously monitored by an in-line analyzer and recorded at least once every 15 minutes. The analyzer shall be calibrated to the manufacturer’s recommended frequency and specifications. **(XX/22)**

   C. The turbines are limited to fuel containing no more than 4 ppmv by volume H_2S. Records shall be maintained of the applicable pipeline H_2S tariff requirements.

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

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

6. Vents from each Acid Gas Removal Unit must be directed to the thermal oxidizers (TO) or the flares.

   A. The TO combustion chamber outlet temperatures for EPNs: TO-1, TO-2, and TO-3 shall be continuously monitored when waste gas is directed to the TO. The minimum outlet temperature shall be 1400 degrees Fahrenheit on an hourly average basis, until a minimum operating temperature is established by the testing required in Special Condition No. 10, when waste gas is directed to the TO. The outlet temperature must be recorded at least four times an hour (once per quarter of the hour) when waste gas is directed to the TO. The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have accuracy the greater of 1 percent of the temperature being measured or 4.5 degrees Fahrenheit.

   B. A minimum exhaust oxygen content of 3 percent must be maintained on an hourly average. Except for a total duration not to exceed 5% of total thermal oxidizer operating hours, oxygen analyzers shall continuously monitor and record oxygen concentration when waste gas is directed to the thermal oxidizers. It shall record the oxygen readings at least four times an hour (once per quarter of the hour) when waste gas is directed to the TO and averaged hourly for compliance demonstration. A partial operational hour with greater than 30 minutes of data shall count as a valid hour. The oxygen analyzers 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. In lieu of CGAs, the permit holder may elect to replace the oxygen sensor semiannually.

7. The flare systems (EPNs: WTDYFLR1, WTDYFLR2, and MRNFLR) shall achieve a 99% destruction rate efficiency (DRE) for compounds up to three carbons and a 98% DRE for all other compounds. These flares (EPNs: WTDYFLR1, WTDYFLR2, and MRNFLR), except as set forth herein, shall be designed and operated in accordance with the following requirements: **(XX/22)**

   A. The 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 and maintenance 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. EPN: MRNFLR shall not be subject to the minimum heating value requirement of 40 CFR § 60.18 during the process of venting inert gases from ships.

   B. The wet/dry flares (EPNs: WTDYFLR1 and WTDYFLR2) 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 or an infrared monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to within manufacturer’s specifications and shall be calibrated at a frequency in accordance with the manufacturer’s specifications.

   C. The marine flare, EPN: MRNFLR, shall be operated with a flame present at all times when liquefied natural gas carriers (LNGCs) are connected to the vapor transfer arm. During all times when EPN: MRNFLR is in use, the pilot flame shall be continuously monitored by a thermocouple or an infrared monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to within manufacturer’s specifications, and shall be calibrated at a frequency in accordance with the manufacturer's specifications.

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

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

E. The permit holder shall install a continuous flow monitor and composition analyzer or continuous flow monitor and 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, except during periods when the flare is offline or the monitor is undergoing calibrations, and the average hourly values of the flow, composition and heating value shall be recorded each hour.

F. 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.

G. If the VOC content of the vent stream is monitored for purposes of compliance with Special Condition 7.E, 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).

H. 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.

I. 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 determined in accordance with 40 CFR §§60.18(f)(3) 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 application workbook received December 27, 2019.

J. The following requirements apply to the capture system for each flare:

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

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

(3) The control device shall not have a bypass.

(4) A bypass does not include authorized analyzer vents, highpoint bleeder vents, low point drains, or rupture discs upstream of pressure relief valves if the pressure between the disc and relief valve is monitored and recorded at least weekly. A deviation shall be reported if the monitoring or inspections indicate bypass of the control device when it is required to be in service.

K. 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.

L. The flare systems shall comply with Paragraphs E through K of this condition no later than 18 months after issuance of the permit amendment associated with NSR Project No. 327940.

During the 18-month interim period, data from the existing flare flow monitors shall be used in conjunction with stream compositions and calculation methods represented in the permit application (PI-1 dated April 19, 2021, as revised) to demonstrate compliance with the short-term (lb/hr) and annual (tpy) emission limits specified by the MAERT.

8. When conditioning a marine vessel to accept liquefied natural gas (LNG), any associated inert emissions from the LNGC must be routed to EPN: MRNFLR so that EPN: MRNFLR can act as a vent stack during purging of any inert gases. When loading LNGCs, boil off gas that meets the quality and temperature specification must be returned to the process.

Initial Determination of Compliance

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

10. 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: TO-1 through TO-3. 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.

Any deviations from those procedures must be approved by the Executive Director of the TCEQ prior to sampling. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

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

A. The TCEQ 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.

B. For EPNs: TO-1 through TO-3, a CH_4 destruction and removal efficiency (DRE) of at least 99.9% on a one-hour average must be demonstrated. The minimum operating temperature shall be the average temperature at which compliance with the above was demonstrated.

C. The carbon content (CC) of the fuels, except for diesel, shall be obtained by using the methods of 40 CFR § 98.34(b)(4). The molecular weight (MW) of the fuels, except for diesel, shall be determined, by the procedures contained in 40 CFR § 98.34(a)(6). The fuel gross calorific value (GCV) [high heat value (HHV)] of the fuels, except for diesel, shall be determined by the procedures contained in 40 CFR § 98.34(a)(6).

D. 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.

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

11. The permit holder shall install, calibrate, maintain, and operate a system to continuously monitor and record the average hourly fuel consumption of each turbine (EPNs: TRB1 through TRB18) with individual flow measurements being taken no less frequently than once every 15 minutes. The fuel flow meter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. The flow meters shall be accurate to ± 5.0 percent of the unit's maximum flow.

12. 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.

13. The volumetric concentration of CO_2 from each TO stack shall be sampled and analyzed according to 40 CFR §98.234(b) annually. The volumetric concentration of CH_4 from the vent of each Acid Gas Removal Unit shall be sampled and analyzed according to 40 CFR §98.234(b) annually.

14. At each shutdown where the TO is opened for internal inspection or maintenance, each TO (EPNs: TO-1 through TO-3) shall be inspected for damaged internal components, settling of packing, and other degradation of the equipment that would affect system performance. Corrective action shall be taken and documented if degradation is found.

Piping, Valves, Connectors, Pumps, and Compressors - 28M

15. 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 in pipeline quality natural gas service:

A. These conditions 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;

(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.

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

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

H. Damaged or leaking valves or connectors found to be emitting CH_4 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. Damaged or leaking pump, compressor, and agitator seals found to be emitting CH_4 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 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

16. 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.

Calculation Methodology

17. Compliance with the emission limits of the MAERT shall be demonstrated using the data generated through valid monitoring and the applicable equations of 40 Code of Federal Regulations Part 98, Mandatory Greenhouse Gas Reporting. Global warming potentials are to be based on values listed in footnote #3 of the MAERT.

18. In lieu of the requirements of Special Condition No. 17, for a given turbine or TO the permit holder may install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) for CO_2 emission measurements. The CEMS shall meet the specifications and test procedures for CO_2 emission monitoring system at stationary sources, 40 CFR Part 98; or meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 3 and follow the monitoring requirements of 40 CFR § 60.13. The permit holder shall also measure volumetric flow and install a data acquisition and handling system to record all measurements.

Recordkeeping

19. 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 8/31/2017, and subsequent representations submitted to the TCEQ.

C. Any turbine or compressor emissions-related written maintenance plans pursuant to Special Condition No. 2.A.

D. A complete copy of the testing reports and records of performance testing completed pursuant to Special Condition No. 10.

20. 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. For each emergency engine and generators (EPNs: GEN1 through Gen-4, FWPUMP1, and FWPUMP2) hours of operation on a monthly and rolling 12-month basis to show compliance with Special Condition Nos. 3 and 4.

B. For each turbine (EPNs: TRB1 through TRB18)

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

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

(3) Dates and activity performed for emissions related inspections and maintenance pursuant to Special Condition No. 2.A.

C. For each EPNs: TO-1 through TO-3

(1) Hourly combustion chamber outlet temperature

(2) Hourly exhaust oxygen content

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

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

(5) Results of CO_2 sampling required by Special Condition No. 13

(6) Dates of visual inspections and any corrective action required by Special Condition No. 14

D. For each flare system (EPNs: WTDYFLR1, WTDYFLR2, and MRNFLR), records of date and time of pilot flame loss. **(11/20)**

E. For records of MSS:

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

(2) Emissions from the event.

F. Records required by the monitoring program in Special Condition No. 15.

G. Monitoring, quality assurance/quality control requirements, emission calculation methodologies, recordkeeping and reporting requirements related to GHG emissions shall adhere to the applicable requirements in 40 CFR Part 98 and this permit. **(11/20)**

21. Permit holders must keep records sufficient to demonstrate compliance with 30 TAC §116.164. If construction, a physical change or a change in the method of operation results in Prevention of Significant Deterioration (PSD) review for criteria pollutants, 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 the method of operation does not require authorization under 30

TAC §116.164(a). If there is construction, a physical change or a change in the method of operation that will result in a net emissions increase of 75,000 tpy or more CO_2e and PSD review is triggered for criteria pollutants, greenhouse gas emissions are subject to PSD review.

Allowable emission rates and special conditions are updated to be consistent with records required by 30 TAC §116.164. **(11/20)**

Date: DRAFT

Emission Sources - Maximum Allowable Emission Rates

Permit Numbers 105710 and PSDTX1306M1

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

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY (5)
TRB1 TRB2 TRB7 TRB8 TRB13 TRB14	Propane Refrigeration Turbines Emission rates are per turbine	NO_x	39.60	See Annual CAP limits below.
		CO	24.10	
		VOC	0.90	
		SO_2	0.44	
		H_2S	<0.01	
		PM	0.98	
		PM_{10}	0.98	
		$PM_{2.5}$	0.98	
TRB3 TRB4 TRB9 TRB10 TRB15 TRB16	Ethylene Refrigeration Turbines Emission rates are per turbine	NO_x	39.60	
		CO	24.10	
		VOC	0.90	
		SO_2	0.44	
		H_2S	<0.01	
		PM	0.98	
		PM_{10}	0.98	
		$PM_{2.5}$	0.98	
TRB5 TRB6 TRB11 TRB12 TRB17 TRB18	Methane Refrigeration Turbines Emission rates are per turbine	NO_x	39.60	
		CO	24.10	
		VOC	0.90	
		SO_2	0.44	
		H_2S	<0.01	
		PM	0.98	
		PM_{10}	0.98	
		$PM_{2.5}$	0.98	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY (5)
TRB1-TRB18	Annual CAP Six Propane, Six Ethylene, and Six Methane Refrigeration Turbines	NO_x	See hourly limits per turbine above.	3121.92
		CO		1900.26
		VOC		71.28
		SO_2		34.74
		H_2S		0.18
		PM		77.58
		PM_{10}		77.58
		$PM_{2.5}$		77.58
TO-1	Thermal Oxidizer	NO_x	4.69	17.31
		CO	13.84	46.86
		VOC	0.24	0.56
		SO_2	1.44	3.36
		H_2S	<0.01	0.02
		PM	0.58	2.15
		PM_{10}	0.58	2.15
		$PM_{2.5}$	0.58	2.15
TO-2	Thermal Oxidizer	NO_x	4.69	17.31
		CO	13.84	46.86
		VOC	0.24	0.56
		SO_2	1.44	3.36
		H_2S	<0.01	0.02
		PM	0.58	2.15
		PM_{10}	0.58	2.15
		$PM_{2.5}$	0.58	2.15

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY (5)
TO-3	Thermal Oxidizer	NO_x	4.69	17.31
		CO	13.84	46.86
		VOC	0.24	0.56
		SO_2	1.44	3.36
		H_2S	<0.01	0.02
		PM	0.58	2.15
		PM_{10}	0.58	2.15
		$PM_{2.5}$	0.58	2.15
WTDYFLR1	Wet/Dry Gas Flare 1 (Normal Operations)	NO_x	71.02	See Flare Cap limits below.
		CO	282.86	
		VOC	61.25	
		SO_2	4.42	
		H_2S	0.05	
WTDYFLR2	Wet/Dry Gas Flare 2 (Normal Operations)	NO_x	71.02	
		CO	282.86	
		VOC	61.25	
		SO_2	4.42	
		H_2S	0.05	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	**TPY (5)**
WTDYFLR1 and WTDYFLR2	Flare Cap (Normal Operations)	NO_x	71.02	57.81
		CO	282.86	339.19
		VOC	61.25	75.38
		SO_2	4.42	3.48
		H_2S	0.05	0.04
WTDYFLR1	Wet/Dry Gas Flare 1 (MSS)	NO_x	816.68	See Annual Flare Cap (MSS) below.
		CO	3,252.52	
		VOC	2,895.54	
		SO_2	2.20	
		H_2S	0.02	
WTDYFLR2	Wet/Dry Gas Flare 2 (MSS)	NO_x	816.68	
		CO	3,252.52	
		VOC	2,895.54	
		SO_2	2.20	
		H_2S	0.02	
WTDYFLR1 and WTDYFLR2	Annual Flare Cap (MSS)	NO_x	See hourly MSS limits per flare above.	228.09
		CO		908.39
		VOC		116.62
		SO_2		1.02
		H_2S		0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY (5)
MRNFLR	Marine Flare	NO_x	389.73	58.18
		CO	1,552.05	414.77
		VOC	394.37	14.59
		SO_2	<0.01	<0.01
		H_2S	<0.01	<0.01
GEN1	Standby Generator 1	NO_x	28.70	1.30
		CO	5.28	0.24
		VOC	0.32	0.01
		SO_2	0.03	<0.01
		PM	0.16	<0.01
		PM_{10}	0.16	<0.01
		$PM_{2.5}$	0.16	<0.01
GEN2	Standby Generator 2	NO_x	28.70	1.30
		CO	5.28	0.24
		VOC	0.32	0.01
		SO_2	0.03	<0.01
		PM	0.16	<0.01
		PM_{10}	0.16	<0.01
		$PM_{2.5}$	0.16	<0.01
GEN3	Standby Generator 3	NO_x	28.70	1.30
		CO	5.28	0.24
		VOC	0.32	0.01
		SO_2	0.03	<0.01
		PM	0.16	<0.01
		PM_{10}	0.16	<0.01
		$PM_{2.5}$	0.16	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	**TPY (5)**
GEN4	Standby Generator 4	NO_x	28.70	1.30
		CO	5.28	0.24
		VOC	0.32	0.01
		SO_2	0.03	<0.01
		PM	0.16	<0.01
		PM_{10}	0.16	<0.01
		$PM_{2.5}$	0.16	<0.01
FWPUMP1	Diesel Firewater Pump 1	NO_x	2.90	0.13
		CO	0.69	0.03
		VOC	0.08	<0.01
		SO_2	<0.01	<0.01
		PM	0.10	<0.01
		PM_{10}	0.10	<0.01
		$PM_{2.5}$	0.10	<0.01
FWPUMP2	Diesel Firewater Pump 2	NO_x	2.90	0.13
		CO	0.69	0.03
		VOC	0.08	<0.01
		SO_2	<0.01	<0.01
		PM	0.10	<0.01
		PM_{10}	0.10	<0.01
		$PM_{2.5}$	0.10	<0.01
IFRTK1	Condensate Tank	VOC	0.60	1.27
TRKLD	Truck Loading	VOC	1.33	1.91

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates (4)	
			lbs/hour	TPY (5)
TRKVCU	Condensate Truck Loading VCU	NO_x	5.11	22.40
		CO	2.96	12.99
		VOC	1.02	1.47
		SO_2	0.02	0.09
		PM	0.28	1.21
		PM_{10}	0.28	1.21
		$PM_{2.5}$	0.28	1.21
WWLD	Wastewater Truck Loading	VOC	3.95	0.03
WWTK1	Wastewater Tank	VOC	0.18	<0.01
TK1902	Spent Scavenger Tank	VOC	0.01	<0.01
SCAVLD	Spent Scavenger Loading	VOC	<0.01	<0.01
DSLTK1	Diesel Tank	VOC	0.08	<0.01
DSLTK2	Diesel Tank	VOC	0.08	<0.01
DSLTK3	Diesel Tank	VOC	0.08	<0.01
DSLTK4	Diesel Tank	VOC	0.08	<0.01
FWPTK1	Diesel Tank	VOC	0.05	<0.01
FWPTK2	Diesel Tank	VOC	0.05	<0.01
GDFTK1	Diesel Tank	VOC	0.08	<0.01
GDFTK2	Gasoline Tank	VOC	14.52	0.31
AMNTK1	Amine Storage Tank	VOC	<0.01	<0.01
AMNSRG1	Amine Surge Tank - MSS	VOC	<0.01	<0.01
AMNSRG2	Amine Surge Tank - MSS	VOC	<0.01	<0.01
AMNSRG3	Amine Surge Tank - MSS	VOC	<0.01	<0.01
FUG	Fugitive Emissions (6)	VOC	18.12	79.40
		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 (4)	
			lbs/hour	TPY (5)
TRKMSS	Truck Loading (MSS)	VOC	43.05	0.49

(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
(4) Planned startup and shutdown (SS) lbs/hour emissions for all pollutants are authorized even if not specifically identified as SS.
(5) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.
(6) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.

Date: DRAFT

Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPSDTX123M1

This table lists the maximum allowable emission rates of greenhouse gas (GHG) emissions, as defined in Title 30 Texas Administrative Code § 101.1, for all sources of GHG air contaminants on the applicant's property that are authorized 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 authorized by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
TRB1-TRB18	Annual cap Six Propane, Six Ethylene, and Six Methane Refrigeration Turbines	CO_2 (5)	3,963,366
		CH_4 (5)	75
		N_2O (5)	8
		CO_2e	3,967,486
TO-1	Thermal Oxidizer	CO_2 (5)	360,494
		CH_4 (5)	11
		N_2O (5)	<1
		CO_2e	360,789
TO-2	Thermal Oxidizer	CO_2 (5)	360,494
		CH_4 (5)	11
		N_2O (5)	<1
		CO_2e	360,789
TO-3	Thermal Oxidizer	CO_2 (5)	360,494
		CH_4 (5)	11
		N_2O (5)	<1
		CO_2e	360,789
WTDYFLR1, WTDYFLR2	Annual Flare Cap (Continuous and MSS)	CO_2 (5)(6)	339,287
		CH_4 (5)(6)	1,682
		N_2O (5)(6)	<1
		CO_2e (6)	381,499
MRNFLR	Marine Flare	CO_2 (5)	87,889
		CH_4 (5)	672.6
		N_2O (5)	<1
		CO_2e	104,759

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
GEN1	Standby Generator 1	CO_2 (5)	129
		CH_4 (5)	<1
		N_2O (5)	<1
		CO_2e	129
GEN2	Standby Generator 2	CO_2 (5)	129
		CH_4 (5)	<1
		N_2O (5)	<1
		CO_2e	129
GEN3	Standby Generator 3	CO_2 (5)	129
		CH_4 (5)	<1
		N_2O (5)	<1
		CO_2e	129
GEN4	Standby Generator 4	CO_2 (5)	129
		CH_4 (5)	<1
		N_2O (5)	<1
		CO_2e	129
FWPUMP1	Diesel Firewater Pump 1	CO_2 (5)	24
		CH_4 (5)	<1
		N_2O (5)	<1
		CO_2e	24
FWPUMP2	Diesel Firewater Pump 2	CO_2 (5)	24
		CH_4 (5)	<1
		N_2O (5)	<1
		CO_2e	24
TRKVCU	Condensate Truck Loading VCU (6)	CO_2 (5)	21,859
		CH_4 (5)	1
		N_2O (5)	<1
		CO_2e	21,947

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
FUG	Fugitive Emissions (5)(6)	CO_2 (5)	12
		CH_4 (5)	143
		CO_2e	3590
MSS-BOG	BOG Compressor MSS Venting	CH_4 (5)	1
		CO_2e	19

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) CO_2 - carbon dioxide
N_2O - nitrous oxide
CH_4 - methane
HFCs - hydrofluorocarbons
PFCs - perfluorocarbons
SF_6 - sulfur hexafluoride
CO_2e - carbon dioxide equivalents based on the following Global Warming Potentials (1/2015): CO_2 (1), N_2O (298), CH_4(25), SF_6 (22,800), HFC (various), PFC (various)
(4) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period. These rates include emissions from maintenance, startup, and shutdown.
(5) Emission rate is given for informational purposes only and does not constitute enforceable limit.
(6) Emissions updated to be consistent with the records required by 30 TAC §116.164(b)

Date: DRAFT

TCEQ Interoffice Memorandum

To: Lyndon Poole, P.E.
Energy Section

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

From: Sara Hill and Philip Leung
ADMT

Date: February 1, 2022

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

1. Project Identification Information

Permit Application Number: 105710
NSR Project Number: 327940
ADMT Project Number: 7625
County: San Patricio
Published Map: \\tceq4avmgisdata\GISWRK\APD\MODEL PROJECTS\7625\7625.pdf

Air Quality Analysis: Submitted by DiSorbo Consulting, LLC, October 2021, on behalf of Corpus Christi Liquefaction, LLC. Additional information was provided November and December 2021, and January 2022.

2. Report Summary

The air quality analysis (AQA), as supplemented by the ADMT, is acceptable for all review types and pollutants. The results are summarized below.

A. De Minimis Analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results indicate that 1-hr and annual NO_2 exceed the respective de minimis concentrations and require a full impacts analysis. The De Minimis analysis modeling results for all averaging times of SO_2 and CO indicate that the project is below the respective de minimis concentrations and no further analysis is required.

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

The ozone De Minimis level is the EPA recommended De Minimis level. The use of the EPA recommended De Minimis level is sufficient to conclude that a proposed source will not cause or contribute to a violation of an ozone NAAQS based on the analyses documented in EPA guidance and policy memoranda[3].

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

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

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
SO_2	1-hr	4	7.8
SO_2	3-hr	3	25
SO_2	24-hr	2	5
SO_2	Annual	0.4	1
NO_2	1-hr	80	7.5
NO_2	Annual	8	1
CO	1-hr	339	2000
CO	8-hr	123	500

The GLCmax for 1-hr NO_2 is based on the highest five-year average of the maximum predicted concentrations determined for each receptor.

The GLCmax reported in the AQA for 1-hr SO_2 represents the maximum predicted concentration over five years of meteorological data rather than the highest five-year average of the maximum predicted concentrations determined for each receptor. The ADMT determined overall conclusions do not change since the difference between the two GLCmax are less than 0.3 µg/m^3**.**

The applicant did not provide an annual SO_2 analysis to determine if an annual Full Increment analysis is needed. The ADMT supplemented the annual SO_2 results in Table 1 above by multiplying the 1-hr maximum predicted concentration by 0.1.

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

Intermittent guidance was relied on for the 1-hr NO_2 PSD De Minimis analysis.

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

Pollutant	Averaging Time	GLCmax (ppb)	De Minimis (ppb)
O_3	8-hr	3	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 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 3000 tpy and 500 tpy (NO_x and VOC, respectively) Harris County source, the applicant estimated an 8-hr O_3 concentration of 3 ppb. When the estimates of ozone concentrations from the project emissions are added together, the results are greater than the De Minimis level.

The applicant reported two different project NO_x emissions totals in the AQA. The ADMT confirmed that the appropriate project NO_x emissions total was used in the calculations.

B. Air Quality Monitoring

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

Table 3. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (µg/m^3)	Significance (µg/m^3)
SO_2	24-hr	2	13
NO_2	Annual	8	14
CO	8-hr	123	575

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

Since the project has a net emissions increase of 100 tons per year (tpy) or more of volatile organic compounds or nitrogen oxides, the applicant evaluated ambient O_3 monitoring data to satisfy requirements in 40 CFR 52.21 (i)(5)(i)(f).

A background concentration for O_3 was obtained from the EPA AIRS monitor 483550025 located at 902 Airport Blvd, Corpus Christi, Nueces County. A three-year average (2018-2020) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis (61 ppb). The use of the monitor is reasonable based on the applicant's analysis of the surrounding land use and a quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site. The applicant also reviewed EPA AIRS monitor 483550026; however, the background concentration from EPA AIRS monitor 483550025 was more conservative. The background concentration was also used as part of the NAAQS analysis.

C. National Ambient Air Quality Standard (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 1-hr and annual NO_2 and 8-hr O_3 exceed the respective de minimis concentration and require a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

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

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. = [Background + GLCmax] (µg/m^3)	Standard (µg/m^3)
NO_2	1-hr	142	35	177	188

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Conc. = [Background + GLCmax] ($\mu g/m^3$)	Standard ($\mu g/m^3$)
NO_2	Annual	22	4	26	100

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.

The annual NO_2 GLCmax is the maximum predicted concentration over five years of meteorological data.

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 480391016 located at 109B Brazoria Hwy 332 West, Lake Jackson, Brazoria County. The three-year average (2016-2018) of the 98th percentile of the annual distribution of the maximum daily 1-hr concentrations was used for the 1-hr NO_2 value. The annual concentration from 2020 was used for the annual NO_2 value. The applicant did not evaluate the most recent available monitoring data for 1-hr NO_2; however, the applicant's use of an older dataset yields more conservative results. The use of this monitor is reasonable based on the applicant's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

Table 5. Total Ozone Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (ppb)	Background (ppb)	Total Conc. = [Background + GLCmax] (ppb)	Standard (ppb)
O_3	8-hr	5	61	66	70

The applicant performed an O_3 analysis as part of the PSD AQA. The applicant evaluated project sources and sources within 10 kilometers (km) of the project site authorized within the last two years with significant increases of O_3 precursor emissions (NO_x and VOC). For the 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 3000 tpy and 500 tpy (NO_x and VOC, respectively) Harris County source, the applicant estimated an 8-hr O_3 concentration of 5 ppb. When the estimates of ozone concentrations from the project emissions are added to the background concentration listed in the table above, the results are less than the NAAQS.

For the estimated 8-hr O_3 concentration, the applicant did not provide justification for using data associated with the 3000 tpy and 90 feet stack height Harris County source for the NO_x MERP and 500 tpy and 10 feet stack height Harris County source for the VOC MERP for all off-property sources that were considered in the estimated 8-hr O_3 concentration. The ADMT conducted a test calculation using the worst-case MERP values for Harris County, and determined that overall conclusions do not change.

D. Increment Analysis

The De Minimis analysis modeling results indicate that annual NO_2 exceeds the respective de minimis concentration and requires a PSD increment analysis.

Table 6. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (µg/m^3)	Increment (µg/m^3)
NO_2	Annual	22	25

The GLCmax for annual NO_2 represents the maximum predicted concentration over five years of meteorological data.

E. Additional Impacts Analysis

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

The ADMT evaluated predicted concentrations from the proposed project to determine if emissions could adversely affect a Class I area. The nearest Class I area, Big Bend National Park, is located approximately 565 km from the proposed site.

The predicted concentrations of 1-hr NO_2 and 1-hr SO_2 are greater than de minimis levels at a distance of 50 km from the proposed sources in the direction of the Big Bend National Park Class I area. The Big Bend National Park Class I area is an additional 515 km from the location where the predicted concentrations of 1-hr NO_2 and 1-hr SO_2 are greater than de minimis. Based on the predicted concentration gradients, NO_2 and SO_2 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 7. Project-Related Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
SO_2	1-hr	4	20.42

The GLCmax reported in the AQA for 1-hr SO_2 is the highest five-year average of the maximum predicted concentrations determined for each receptor rather than the maximum predicted concentration over five years of meteorological data. The ADMT determined overall conclusions do not change since the difference between the two GLCmax are less than 0.3 µg/m^3.

Table 8. Generic Modeling Results

Source ID	1-hr GLCmax (µg/m^3 per lb/hr)	Annual GLCmax (µg/m^3 per tpy)
WTDYFLR1	0.03	< 0.01
WTDYFLR2	0.03	< 0.01

Source ID	1-hr GLCmax (µg/m^3 per lb/hr)	Annual GLCmax (µg/m^3 per tpy)
FUG	20.44	0.05
FLRM1	0.01	< 0.01
FLRM2	0.01	< 0.01
IFRTK1	23.60	0.06
TRKLD	40.53	0.07
TRKVCU	4.85	0.01
WWTK1	42.66	0.10
WWLD	46.97	0.10
TO1	2.59	0.02
TO2	1.04	0.01
TO3	0.75	<0.01
TRKMSS	42.32	0.09
MRNFLR	0.02	< 0.01
AMNSRG1	54.97	0.14
AMNSRG2	33.71	0.06
AMNSRG3	57.58	0.08
TK1902	58.44	0.11
SCAVLD	46.97	0.10

The UIMs used for model IDs TRKMSS and MRNFLR in the MERA calculations are greater than the model outputs reported above. This is conservative.

Table 9. Minor NSR Site-wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax (µg/m^3)	GLCmax Location	ESL (µg/m^3)
N-methyldiethanolamine	105-59-9	1-hr	52	Eastern Property Line	96

Pollutant	CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	GLCmax Location	ESL ($\mu g/m^3$)
benzene	71-43-2	1-hr	61	Western Property Line	170
ethylene	74-85-1	1-hr	137	Eastern Property Line	1400

The GLCmax location is listed in Table 9 above.

The site-wide 1-hr GLCmax for N-methyldiethanolamine (ADEA) was inadvertently reported under annual monoethanolamine on the Health Effect Modeling Results sheet of the EMEW. The results from the modeling output are reported in Table 9 above.

3. Model Used and Modeling Techniques

AERMOD (Version 21112) was used in a refined screening mode.

For the MERA Step 3 health effects analysis, unitized emission rates of 1 lb/hr and 1 tpy were used to predict a generic short-term and long-term impact for each source, respectively. 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. Health effect pollutants that went on to site-wide modeling were evaluated with pollutant specific modeling.

According to the applicant, EPN AMNTK1 will not operate simultaneously with EPNs AMNSRG1-3. Additionally, the applicant stated that evaluating EPNs AMNSRG1-3 is more conservative than evaluating EPN AMNTK1. However, the applicant did not provide sufficient justification for this statement. The ADMT conducted a test modeling run and determined that evaluating EPNs AMNSRG1-3 is more conservative than evaluating EPN AMNTK1.

For the short term NO_2 analysis, a unitized emission rate of 1 lb/hr was used to predict a generic short-term impact for model IDs WTDFLR1 and WTDFLR2. The worst-case flare associated with the highest unit impact was used to evaluate the full routine emission cap.

For the NO_2 analyses, according to the applicant, the flare MSS emissions (model IDs FLRM1 and FLRM2) can occur at the location of either flare (model IDs WTDYFLR1 or WTDYFLR2). A unitized emission rate of 1 lb/hr was used to predict a generic short-term impact for each flare. However, the location of the worst-case flare (model ID WTDYFLR2) associated with the highest unit impact was not used in the model. The ADMT determined that overall conclusions would not change since the difference in the unit impacts at the location of model IDs WTDYFLR1 and WTDYFLR2 is approximately 0.00001 $\mu g/m^3$ per lb/hr.

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

A. Land Use

User-defined surface characteristics of albedo, Bowen ratio, and surface roughness were calculated with AERSURFACE using a one km radius from an adjacent site discussed below. The calculated surface characteristic values were used as input for the AERMET meteorological processor.

The applicant centered the AERSURFACE analysis approximately 1 km east of the project sources due to outdated NLCD land cover data that contains undeveloped land where the project site is located. A representative center location was chosen where there is an existing facility characterized as industrial land use.

For the AERSURFACE analysis, the applicant determined the surface moisture by reviewing the past 34 years of rainfall records, rather than 30 years of rainfall records. This will not significantly affect overall results.

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 2016-2020 calendar years. Raw surface and upper air meteorological data were processed using AERMET (Version 21112).

Surface Station and ID: Corpus Christi, TX (Station #: 12924)
Upper Air Station and ID: Corpus Christi, TX (Station #: 12924)
Meteorological Dataset: 2020 for health effects analyses; 2016-2020 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.

The site-wide health effect analyses used a receptor grid with denser coverage around the northern portion of the site. This is acceptable.

A few receptors have elevation discrepancies; however, given the locations of the GLCmax, this is not expected to affect overall results.

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

Except as noted below, 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.

Model IDs MSTO1-7 have inconsistent reported parameters between the EMEW and the supplemental AQA. However, the more conservative parameters were modeled.

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

The ADMT could not confirm several modeled off-property source parameters and emissions rates for the 1-hr and annual NO_2 NAAQS analyses. The ADMT determined that overall conclusions would not change given the locations of the 1-hr and annual NO_2 NAAQS GLCmax.

For the annual benzene analysis at Step 3 of the MERA analysis, the applicant evaluated site-wide emission rates for EPNs TO-(1-3). This is conservative.

For the 1-hr NO_2 de Minimis and NAAQS analyses, emissions from the emergency generators (EPNs SGEN1-4), emergency fire water pump engines (EPNs FWPUMP1-2, MSFWP1-2), diesel generators (EPNs MSGEN1-8), and wet/dry gas flare propane depressuring MSS (EPN FLRM1) were modeled with an annual average emission rate, consistent with EPA guidance for evaluating intermittent emissions. Emissions from the emergency generators, emergency fire water pump engines, and diesel generators were represented to occur for no more than 100 hours per year, each. Emissions from the wet/dry gas flare propane depressuring MSS were represented to occur for no more than 56 hours per year.

With the exceptions 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: Lyndon Poole, P.E.
Energy Section

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

From: Sara Hill
ADMT

Date: April 27, 2022

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

1. Project Identification Information

Permit Application Number: 105710
NSR Project Number: 327940
ADMT Project Number: 7883
County: San Patricio
Published Map: \\tceq4avmgisdata\GISWRK\APD\MODEL PROJECTS\7883\7883.pdf

Air Quality Analysis: Submitted by DiSorbo Consulting, LLC, March 2022, on behalf of Corpus Christi Liquefaction, LLC. Additional information was provided April 2022.

2. Report Summary

This is the second modeling audit for this NSR Project number. The modeling audit was conducted to remove the operational limitations previously modeled for EPNs AMNSRG1-3 and AMNTK1 in the n-methyldiethanolamine (aMDEA) analysis. This second modeling audit memorandum only addresses the evaluation of aMDEA. The results for all other demonstrations can be found in the first modeling audit memorandum dated February 1, 2022 (WCC Content ID 5929311).

The air quality analysis is acceptable. The results are summarized below.

A. Minor Source NSR Air Toxics Analysis

Table 1. Minor NSR Site-wide Modeling Results for Health Effects

Pollutant	CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	GLCmax Location	ESL ($\mu g/m^3$)
n-methyldiethanolamine	105-59-9	1-hr	52	E property line	96

3. Model Used and Modeling Techniques

AERMOD (Version 21112) was used.

A. Land Use

User-defined surface characteristics of albedo, Bowen ratio, and surface roughness were calculated with AERSURFACE using a one km radius from an adjacent site discussed below. The calculated surface characteristic values were used as input for the AERMET meteorological processor.

The applicant centered the AERSURFACE analysis approximately 1 km east of the project sources due to outdated NLCD land cover data that contains undeveloped land where the project site is located. A representative center location was chosen where there is an existing facility characterized as industrial land use.

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 2020 calendar year. Raw surface and upper air meteorological data were processed using AERMET (Version 21112).

Surface Station and ID: Corpus Christi, TX (Station #: 12924)
Upper Air Station and ID: Corpus Christi, TX (Station #: 12924)
Meteorological Dataset: 2020
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)

Building downwash is not applicable for volume source modeling.

4. Modeling Emissions Inventory

Except as noted below, the modeled emission volume source parameters and rates were consistent with the modeling report. The source characterizations used to represent the sources were appropriate.

The applicant reported source model ID AMNTK1 with elevation and lateral dimension parameters that are inconsistent with the modeled parameters. However, the ADMT conducted test modeling with the reported parameters and determined that overall results do not change.

Maximum allowable hourly emission rates were used for the short-term averaging time analysis.

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To request a more accessible version of this report, please contact the TCEQ Help Desk at (512) 239-4357.

Compliance History Report

Compliance History Report for CN604136374, RN104104716, Rating Year 2020 which includes Compliance History (CH) components from September 1, 2015, through August 31, 2020.

Customer, Respondent, or Owner/Operator:	CN604136374, Corpus Christi Liquefaction, LLC	**Classification:** SATISFACTORY	**Rating:** 3.33
Regulated Entity:	RN104104716, CORPUS CHRISTI LIQUEFACTION	**Classification:** SATISFACTORY	**Rating:** 3.33
Complexity Points:	13	**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
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 24568
TAX RELIEF ID NUMBER 25856	

Compliance History Period: September 01, 2015 to August 31, 2020 **Rating Year:** 2020 **Rating Date:** 09/01/2020

Date Compliance History Report Prepared: October 20, 2023

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

Component Period Selected: April 20, 2016 to April 20, 2021

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

Name: Scott McKee **Phone:** (512) 239-1255

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:

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	December 06, 2016**	(1363499)
Item 2*	January 04, 2017**	(1779583)
Item 3*	April 17, 2017**	(1779538)
Item 4*	July 24, 2017**	(1779553)
Item 5*	October 10, 2017**	(1779568)
Item 6*	November 30, 2017**	(1449601)
Item 7*	January 23, 2018**	(1779584)
Item 8*	April 11, 2018**	(1779539)
Item 9*	June 13, 2018**	(1467137)
Item 10	July 26, 2018**	(1779554)
Item 11*	October 18, 2018**	(1517698)
Item 12*	October 24, 2018**	(1779569)
Item 13*	December 21, 2018**	(1536797)
Item 14*	January 24, 2019**	(1779585)
Item 15*	February 19, 2019**	(1538368)
Item 16*	April 23, 2019**	(1779540)
Item 17*	July 23, 2019**	(1779555)
Item 18*	August 14, 2019**	(1578932)
Item 19*	August 27, 2019**	(1578942)
Item 20	August 29, 2019**	(1581779)
Item 21*	September 13, 2019**	(1592193)
Item 22*	October 23, 2019**	(1779570)
Item 23*	November 25, 2019**	(1610691)
Item 24*	November 26, 2019**	(1605788)
Item 25*	January 22, 2020**	(1779586)
Item 26*	January 28, 2020**	(1603853)
Item 27*	February 11, 2020**	(1617950)
Item 28*	March 06, 2020**	(1632574)
Item 29*	April 20, 2020**	(1779541)
Item 30*	May 14, 2020**	(1645407)
Item 31*	May 21, 2020**	(1646900)

Item 32*	June 24, 2020**	(1652577)
Item 33*	July 23, 2020**	(1779556)
Item 34*	August 13, 2020**	(1622660)
Item 35	August 26, 2020**	(1670275)
Item 36	August 27, 2020**	(1664747)
Item 37*	October 06, 2020	(1679110)
Item 38*	October 09, 2020	(1622659)
Item 39*	October 23, 2020	(1678317)
Item 40	October 26, 2020	(1779571)
Item 41*	October 29, 2020	(1685520)
Item 42*	November 13, 2020	(1659743)
Item 43*	November 17, 2020	(1690485)
Item 44	November 23, 2020	(1686774)
Item 45*	December 17, 2020	(1697140)
Item 46*	December 23, 2020	(1697125)
Item 47	January 19, 2021	(1779587)
Item 48*	January 25, 2021	(1692337)
Item 49*	April 15, 2021	(1706110)

* No violations documented during this investigation

**Investigation occurred between 09/01/2015 and 08/31/2020.

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: 12/06/2016 (1363499)

Self Report? NO Classification: Minor

Citation: 30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 116, SubChapter B 116.115(b)(2)(A)
30 TAC Chapter 122, SubChapter B 122.143(4)
5C THSC Chapter 382 382.085(b)
General Conditions PERMIT
Special Terms and Condition 9 OP

Description: Failure to submit a report of construction progress to the appropriate regional office of the commission no later than 15 working days after the start of construction.

Self Report? NO Classification: Minor

Citation: 30 TAC Chapter 101, SubChapter A 101.20(1)
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 60.7(a)(1)
5C THSC Chapter 382 382.085(b)
Special Condition 2A PERMIT
STC 6A OP

Description: Failure to submit a notification of the date construction commenced no later than 30 days after such date.

Self Report? NO Classification: Minor

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.

2 Date: 04/30/2018 (1779554)

Self Report? YES Classification: Moderate

Citation: 2D TWC Chapter 26, SubChapter A 26.121(a)
30 TAC Chapter 305, SubChapter F 305.125(1)

Description: Failure to meet the limit for one or more permit parameter

3 Date: 06/30/2018 (1779564)

Self Report? YES Classification: Moderate

Citation: 2D TWC Chapter 26, SubChapter A 26.121(a)
30 TAC Chapter 305, SubChapter F 305.125(1)

Description: Failure to meet the limit for one or more permit parameter

4 Date: 08/29/2019 (1581779)

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 116, SubChapter B 116.115(c)
30 TAC Chapter 122, SubChapter B 122.143(4)
5C THSC Chapter 382 382.085(b)
General Terms and Conditions OP
Special Condition 15E PERMIT
Special Term and Condition 9 OP

Description: Failure to equip each open ended valve or line (OEL) with an appropriately sized cap, blind flange, plug, or a second valve to seal the line.

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)
General Terms and Conditions OP
PSDTX1306M1, Special Condition 23D PERMIT
Special Term and Condition 9 OP

Description: Failure to maintain records of quarterly visible emissions observations.

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)
General Terms and Conditions OP
PSDTX1306M1, Special Condition 13 PERMIT
Special Term and Condition 9 OP

Description: Failure to conduct quarterly visible emissions observations.

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.

5* Date: 06/30/2020 (1779566)

Self Report? YES Classification: Moderate

Citation: 2D TWC Chapter 26, SubChapter A 26.121(a)
30 TAC Chapter 305, SubChapter F 305.125(1)

Description: Failure to meet the limit for one or more permit parameter

6* Date: 07/31/2020 (1779571)

Self Report? YES Classification: Moderate

Citation: 2D TWC Chapter 26, SubChapter A 26.121(a)
30 TAC Chapter 305, SubChapter F 305.125(1)

Description: Failure to meet the limit for one or more permit parameter

7* Date: 08/27/2020 (1664747)

Self Report? NO Classification: Moderate

Citation: /PSDTX1306M1, SC 13 PERMIT
/PSDTX1306M1, SC 23D PERMIT
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)
STC 3(A)(iv)(1) OP
STC 9 OP

Description: Failure to perform quarterly visible emissions observations.

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 122, SubChapter C 122.210(a)
5C THSC Chapter 382 382.085(b)

Description: Failure to operate as represented.

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 111, SubChapter A 111.111(a)(4)(A)
30 TAC Chapter 122, SubChapter B 122.143(4)
30 TAC Chapter 122, SubChapter B 122.143(6)
5C THSC Chapter 382 382.085(b)

STC 1A OP
Description: Failure to operate flare without visible emissions.
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)
SC 6(B) PERMIT
STC 9 OP
Description: Failure to a perform cylinder gas audit (CGA) as required.
Self Report? NO Classification: Moderate
Citation: /PSDTX1306M1, SC 10 PERMIT
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)
STC 9 OP
Description: Failure to comply with thermal oxidizer operational requirements.
Self Report? NO Classification: Moderate
Citation: /PSDTX1306M1, SC 11(A) PERMIT
30 TAC Chapter 101, SubChapter A 101.20(3)
30 TAC Chapter 116, SubChapter B 116.115(b)
30 TAC Chapter 116, SubChapter B 116.115(c)
30 TAC Chapter 122, SubChapter B 122.143(4)
30 TAC Chapter 122, SubChapter B 122.143(6)
40 CFR Chapter 60, SubChapter C, PT 60, SubPT A 60.18(c)(3)(ii)
5C THSC Chapter 382 382.085(b)
STC 1A OP
STC 9 OP
Description: Failure to operate a flare above minimum required net heating value.
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, SC 4(C) PERMIT
STC 9 OP
Description: Failure to comply with turbine planned startup or shutdown time limits.
Self Report? NO Classification: Moderate
Citation: /PSDTX1306M1, SC 1 PERMIT
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)
STC 9 OP
Description: Failure to comply with permitted emission rates for Wet/Dry Gas Flare 1 (emission point number [EPN] WTDYFLR1).
Self Report? NO Classification: Moderate
Citation: /PSDTX1306M1, SC 1 PERMIT
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)
STC 9 OP
Description: Failure to comply with permitted emission rates for the Marine Flare (EPN MRNFLR).
Self Report? NO Classification: Moderate
Citation: /PSDTX1306M, SC 18E OP
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)
STC 9 OP
Description: Failure to equip each open ended valve or line (OEL) with an appropriately sized cap, blind flange, plug, or a second valve to seal the line.
Self Report? NO Classification: Moderate
Citation: 30 TAC Chapter 113, SubChapter C 113.880
30 TAC Chapter 122, SubChapter B 122.143(4)
30 TAC Chapter 122, SubChapter B 122.143(6)

40 CFR Chapter 63, SubChapter C, PT 63, SubPT EEEE 63.2343(c)
5C THSC Chapter 382 382.085(b)
STC 1A OP
STC 1E OP

Description: Failure to submit notifications by the required timeframe.

Self Report? NO Classification: Moderate

Citation: /PSDTX1306M1, SC 1 PERMIT
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)
STC 9 OP

Description: Failure to comply with permitted emission rates for the Annual Flare Cap (EPN WTDYFLR1-2).

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 115, SubChapter B 115.112(c)(1)
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)
STC 1A OP
STC 4 OP
STC 8 OP

Description: Failure to monitor at carbon canisters as required.

Self Report? NO Classification: Moderate

Citation: 30 TAC Chapter 115, SubChapter B 115.112(c)(1)
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)
STC 1A OP
STC 4 OP
STC 8 OP

Description: Failure to replace a carbon canister within the required time interval.

Self Report? NO Classification: Moderate

Citation: /PSDTX1306M1, SC 23 PERMIT
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)
STC 15 OP
STC 9 OP

Description: Failure to maintain records.

8 Date: 10/31/2020 (1779587)

Self Report? YES Classification: Moderate

Citation: 2D TWC Chapter 26, SubChapter A 26.121(a)
30 TAC Chapter 305, SubChapter F 305.125(1)

Description: Failure to meet the limit for one or more permit parameter

* NOVs applicable for the Compliance History rating period 9/1/2015 to 8/31/2020

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.l

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.l

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

*NOA/DOVs applicable for the Compliance History rating period 09/01/2015 to 8/31/2020

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

Permit Amendment
Source Analysis & Technical Review

Company	**Corpus Christi Liquefaction, LLC**	Permit Numbers	**105710, PSDTX1306M1 and GHGPSDTX123M1**
City	**Gregory**	Project Number	**327940**
County	**San Patricio**	Regulated Entity Number	**RN104104716**
Project Type	**Amendment and Voluntary Update**	Customer Reference Number	**CN604136374**
Project Reviewer	**Lyndon Poole, P.E.**	Received Date	**April 20, 2021**
Site Name	**Corpus Christi Liquefaction**		

Project Overview

Corpus Christi Liquefaction, LLC (CCL), a subsidiary of Cheniere Energy, Inc., owns and operates a natural gas liquefaction and export terminal located in Gregory, San Patricio County, Texas. The liquified natural gas (LNG) terminal includes three liquefaction trains ("Stage I/II Project") authorized under New Source Review (NSR) Permit Number 105710 and Prevention of Significant Deterioration (PSD) Permit Numbers PSDTX1306M1 and GHGPSDTX123M1. CCL has submitted an amendment application to update as-built flare emissions and operations: to correct stream compositions and vent rates, to authorize flaring of boil-off gas from LNG tanks when the upstream Sinton Compressor Facility is shut down, and to remove the Totally Enclosed Ground Flare (TEGF) from the permit. The application also requests authorization of a new LNG marine loading scenario.

The as-built portion of the proposed amendment is considered a retrospective correction of representations associated with the original CCL Stage I/II Project, authorized by a Prevention of Significant Deterioration (PSD) permit issued September 12, 2014. Subsequent as-built amendments also included a modification of the PSD permit on July 20, 2018. The application also includes a voluntary update to the Greenhouse Gas (GHG) PSD permit. For additional detail please see the Project Description section below.

Emission Summary

A	B	C	D	E	F
Air Contaminant	Current Allowable Emission Rates (tpy)	Proposed Allowable Emission Rates (tpy)	Change in Allowable Emission Rates (tpy)	Retrospective Project Changes at Major Sources (tpy, Baseline Actual to Allowable)	New Project Changes at Major Sources (tpy, Baseline Actual to Allowable)
PM	85.30	85.30	0.00	0.00	0.00
PM_{10}	85.30	85.30	0.00	0.00	0.00
$PM_{2.5}$	85.30	85.30	0.00	0.00	0.00
VOC	353.13	364.63	11.50	364.63	10.99
NO_X	3,541.40	3,545.79	4.39	3,545.79	10.52
CO	3,621.77	3,717.20	95.43	3,717.20	10.89
SO_2	49.39	49.48	0.09	49.48	0.01
H_2S	0.31	0.31	0.00	0.31	0.01
CO_2	5,474,166	5,494,459	20,293	5,494,459	2,713
CH_4	2,468.2	2,613.5	145.3	2,613.5	6.60
N_2O	20.00	20.00	0.00	20.00	0.01
CO_2 Equivalent	5,538,226	5,562,201	23,975	5,562,231	2,945

Notes: Column D = Column C minus Column B.
Column E represents a retrospective correction of the original authorization, conservatively based on new proposed allowable emissions minus baseline (assuming baseline emissions = zero).
Column F represents new project emission increases based on a federal analysis of the 2-vessel loading scenario. These emissions are also conservatively included in the retrospective values (Column E).

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	October 19, 2023
Site rating & classification:	3.33 / Satisfactory
Company rating & classification:	3.33 / 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.

Public Notice Information

Requirement	Date
Legislator letters mailed	**4/23/2021**
Date 1st notice published	**5/13/2021**

Requirement	Date
Publication Name: **News of San Patricio**	
Pollutants: **Carbon monoxide, hydrogen sulfide, nitrogen oxides, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less and sulfur dioxide.**	
Date 1st notice Alternate Language published	**5/15/2021**
Publication Name (Alternate Language): **Tejano y Grupero News**	
1st public notice tearsheet(s) received	**6/01/2021**
1st public notice affidavit(s) received	**6/01/2021**
1st public notice certification of sign posting/application availability received	**6/24/2021**
SB709 Notification mailed	**06/03/2021, 12/07/2021, 05/05/2022, 9/22/2022**
Date 2nd notice published	**5/26/2022**
Publication Name: **News Of San Patricio**	
Pollutants: **Carbon monoxide, 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 hazardous air pollutants**	
Date 2nd notice published (Alternate Language)	**6/01/2022**
Publication Name (Alternate Language): **Tejano Y Grupero News**	
2nd public notice tearsheet(s) received	**06/01/2021, 06/08/2022**
2nd public notice affidavit(s) received	**06/08/2022**
2nd public notice certification of sign posting/application availability received	**06/24/2021, 07/06/2022**

Public Interest

Number of comments received	**23**
Number of meeting requests received	**25**
Number of hearing requests received	**23**
Date meeting held	**6/30/2022**
Date response to comments filed with OCC	**7/14/2023**
Date of SOAH hearing	

Federal Rules Applicability

Requirement	
Subject to NSPS?	**Yes.**
Subparts	**A, Kb, IIII, & KKKK.**
Subject to NESHAP?	**No.**
Subparts	**N/A.**
Subject to NESHAP (MACT) for source categories?	**Yes.**
Subparts	**A, EEEE, YYYY, & ZZZZ.**

Nonattainment review applicability:
This site is located in San Patricio County, which is in attainment or unclassified for all pollutants. Therefore, nonattainment review is not applicable.

PSD review applicability:
The site is a major named source under PSD. The proposed as-built project within this amendment, including increased flare vent gas rates (EPNs WTDYFLR1 and WTDYFLR2), stream composition updates at the marine flare (EPN MRNFLR), and flaring of boil-off gas (BOG) when the Sinton Compressor Facility is required by regulation to shut down, is subject to retrospective review based on the original authorization of the Stage I/II construction project (Project No. 182514), which was subject to PSD review in 2014. Since this portion of the current amendment is an as-built correction to the 2014 project, the potential to emit in the original project increase analysis has been corrected as noted in the following table:

Retrospective (As-Built) Project			
Pollutant	PSD Significant Emission Rate (tpy)	Corrected (Retrospective) Project Increase(1) (tpy)	PSD Review Required? (2)
VOC	40	364.63	Yes
NO_X	40	3,545.79	Yes
CO	100	3,717.20	Yes
SO_2	40	49.48	Yes
CO_2e	75,000	5,562,231	Yes

Note (1) The corrected project increase is conservatively based on new proposed allowable emissions minus a baseline of zero.
Note (2) PSD review was conducted on the original authorization (Project No. 182514), and on a subsequent as-built amendment (Project No. 274624) which corrected the original project emission rates.

Requirement

In addition to correcting the original project increase as shown above (i.e., zero baseline to proposed allowable), the retrospective review also examines the magnitude of the emission corrections themselves, in order to determine whether the corrected values exceed the PSD significant emission rate.

This permit application (Project No. 327940) originally contained a correction that would have exceeded the significant emission rate for CO. However, on October 7, 2022 the applicant provided application revisions that reduced the allowable-to-allowable increases for the wet/dry flares. The revised emission calculations were based on a lower vent rate to the flares (from 873 lb/hr per train to 625 lb/hr per train). The resulting emission corrections are below the major modification thresholds, and compliance will be demonstrated through the flare monitoring requirements of Special Condition No. 14.E and the monthly emission calculations required by Special Condition No. 14.N.

Retrospective (As-Built) Project			
Pollutant	PSD Significant Emission Rate (tpy)	Magnitude of Newly Quantified Corrections (tpy)	New PSD Review Triggered?
VOC	40	11.50	No
NO_X	40	4.39	No
CO	100	95.43	No
SO_2	40	0.09	No
CO_2e	75,000	23,975	No

As indicated in the table above, the retrospective emission correction values do not trigger a new PSD review.

The new project within this amendment includes a proposal to vent two LNG carriers to the marine flare (EPN MRNFLR) simultaneously, instead of one carrier at a time. This scenario does not result in any allowable annual emission increases. However, it does result in short-term emissions increases at the marine flare, and therefore is considered a modification. Further, the short-term increases could result in actual emission increases in the annual rates. A federal analysis was therefore performed. Since the Train 3 facilities have been in operation less than two years, the current allowable emission rates at the marine flare were used as baseline emissions. The resulting project increases are shown in the following table:

New Project			
Pollutant	PSD Significant Emission Rate (tpy)	New Project Increase (tpy)	PSD Review Required?
VOC	40	10.99	No
NO_X	40	10.52	No
CO	100	10.89	No
SO_2	40	0.01	No
H_2S	10	0.01	No
GHG	N/A. GHG PSD is not applicable if non-GHG pollutants do not trigger PSD review.		

The new project therefore does not trigger PSD review.

Title V Applicability - 30 TAC Chapter 122 Rules

Requirement

Title V applicability: This site is subject to Title V and operates under Permit O3580.

Requirement

Periodic Monitoring (PM) applicability: Periodic monitoring is applicable because the site is a major source subject to 30 TAC Chapter 122.

- Flare periodic monitoring is included in CAM requirements below.
- Continuous monitoring of H_2S (1-hour average) is required for fuel used for thermal oxidizers, flare pilots, and turbines. Fuel is limited to 4 ppmv H_2S.

Compliance Assurance Monitoring (CAM) applicability: CAM is applicable because the site is a major source subject to 30 TAC Chapter 122. The affected flares, EPNs: WTDYFLR1, WTDYFLR2 control more than 100 ton per year of VOC from the LNG trains and are subject to CAM. The following is required for the flares:

- The flare pilot flames are continuously monitored by a thermocouple or an infrared monitor to indicate the control device is functioning
- A continuous flow monitor is required to measure vent stream flow (hourly average).
- A continuous composition monitor or calorimeter is required to ensure minimum heating value (hourly average).
- A monthly audio, visual, and olfactory (AVO) inspection is required for the flare capture systems.
- A bypass is not authorized.
- No visible emissions are authorized for the flares except for a maximum of 5 minutes per any two-hour period.

Process Description

CCL currently operates a natural gas liquefaction and export terminal, which includes the Stage I/II project. Stage I project (Train 1 and 2) is completed, while Stage II (Train 3) is currently under commissioning. LNG is exported via LNG carriers from the marine terminal.

The Stage I/II project is designed to operate three trains continuously (8,760 hours per year) using eighteen GE LM2500+G4 natural gas-fired refrigeration compressor turbines, six on each train. There are two methane, two propane, and two ethylene refrigeration turbines per train. Each train is also equipped with an Acid Gas Removal Unit (AGRU). VOC in the acid gas is controlled using thermal oxidizers or the wet and dry gas flares when the thermal oxidizers are out of service. Heavier compounds in the natural gas are also removed as condensate. Other facilities at the site include gasoline and diesel storage tanks, trucks, standby generators, diesel firewater pump engines, and a marine ground flare.

Project Scope

In September 2014, CCL was authorized to construct the Terminal under the Stage I/II Project (Project No. 182514). Additional amendments were approved on July 20, 2018 (Project No. 274624) and November 4, 2020 (Project No. 310514) to update the permit representations to reflect as-built design of the Stage I/II project. In Project No. 310514, CCL incorporated Standard Permit 158378 by consolidation, which authorized the installation of a totally enclosed ground flare (TEGF).

In the current amendment project, CCL is requesting the following changes to Permit 105710, PSDTX1306M1, and GHGPSDTX123M1:

1. Elevated Flares (EPNs WTDFLR1 and WTDFLR2):
   - Update previously represented vent gas rates to the wet and dry flares and authorize associated emission increases. CCL represents that through operating experience, including the initial startup of Train 3, it has been observed that the process vent gas rates to the wet and dry flares are greater than represented in the November 4, 2020 amendment (Project No. 310514).

2. Marine flare (EPN: MRNFLR):
    a. Authorize simultaneous venting of two LNG carriers and update emissions accordingly. This is the only new project. All other changes are considered as-built or retrospective.
    b. Update represented stream composition to include boil-off gas (BOG) from the LNG tanks.
    c. Update marine flare emissions to account for boil-off gas control during shutdowns at the upstream Sinton Compressor Station. During required regulatory Emergency Shutdown (ESD) testing at the upstream Sinton compressor facility, all CCL trains have to be shut down; therefore BOG, which is normally routed back to the process trains, has to be routed to the marine flare.

3. Remove the totally enclosed ground flare (TEGF), EPN: STG1_2GF from the permit. CCL has determined that the existing control devices can handle the desired steams and the ground flare is therefore not necessary.

4. Update GHG permit (GHGPSDTX123M1) to reflect emission increases from the marine and wet/dry flares.

A summary of changes to the special conditions (SCs) and MAERTs appear below:

Changes to NSR (non-GHG) Special Conditions		
Former SC #	New SC #	Change
7	7	Updated Paragraph A to specify 1-hour averaging period for H_2S monitoring of fuel. Added new Paragraph B to require continuous monitoring of H_2S concentration in fuel gas. Added record keeping requirement for H_2S content in turbine fuel to Paragraph C.
14	14	Added Paragraphs E through I to flare condition to specify requirements for flow monitor and composition analyzer or calorimeter. Added capture system requirements in Paragraphs J and K. Added Paragraph L to allow 18 months to establish compliance with new Paragraphs E through K, and to specify that existing monitors shall be used, along with stream composition and represented calculation methods, to demonstrate MAERT compliance during the 18-month interim period. Added Paragraph M to specify flow and composition data required by Paragraph E shall be used to calculate lb/hr emission rates. Added Paragraph N for annual MAERT compliance, and for demonstration that the retrospective emissions in this project will not exceed major modification thresholds.
-	16	Added operational restriction to limit the number of marine vessels simultaneously venting to marine flare (not to exceed two vessels).
-	17	Added requirement for boil-off gas to be routed to marine flare during emergency shutdown (ESD) testing at upstream Sinton Compressor Facility. Also specified that all marine loading must be shut down during this period. Mass emission rate monitoring is required to ensure that calculated emissions are not exceeded.
16	-	Deleted conditions and references to multi-point ground flare and associated capture system, since installation of the ground flare was cancelled.
17	-	
25	25	Added new Paragraph D to limit propane depressurization to 56 hours per year, as represented in the air quality analysis.
28	28	Added record keeping requirements for H_2S concentration in fuel gas, flare waste gas flow, flare gas composition or heating value, flare capture systems, and short-term flare emission rates.
29	-	Deleted AMOC/AMEL provisions associated with cancelled ground flare.
-	29	Added table listing PBRs incorporated by reference.

Changes to NSR (non-GHG) MAERT	
EPN	Change
WTDFL1	Revised emission rates according to retrospective project.
WTDFLR2	Revised emission rates according to retrospective project.
STG1_2GF	Deleted multi-point ground flare (normal and MSS entries) due to project cancellation.
WTDFL1 and WTDFLR2	Revised emission rates for flare cap according to retrospective project.
MRNFLR	Revised emission rates according to retrospective and new projects.

Changes to GHG Special Conditions		
Former SC #	New SC #	Change
7	7	Added Paragraphs E through I to flare condition to specify requirements for flow monitor and composition analyzer or calorimeter. Also added capture system requirements in Paragraphs J and K.
9	-	Deleted conditions and references to multi-point ground flare since installation of the ground flare was cancelled.

Changes to GHG MAERT	
EPN	Change
STG1_2GF	Deleted multi-point ground flare (normal and MSS entries) due to project cancellation.
WTDFL1 and WTDFLR2	Revised emission rates for flare cap according to retrospective project.
MRNFLR	Revised emission rates according to retrospective and new projects.

Best Available Control Technology

Source Name	**EPN**	**Best Available Control Technology Description**
Wet/Dry and Marine Flares	WTDYFLR1, WTDYFLR2, and MRNFLR	**VOC:** Meets 40 CFR 60.18. Destruction Efficiency: 99% for certain compounds up to three carbons, 98% otherwise. Flow monitor is required. Composition or BTU analyzer is required. **SO_2/H_2S:** Flare pilot fuel limited to no more than 4 ppmv H_2S.
Marine Loading of LNG	MRNFLR	**Methane (CH_4):** Use of cryogenic temperature and insulation of loading arms to minimize boil-off gas. Boil-off gas routed to the marine flare. **VOC:** Routing warm or inerted vapors during vessel conditioning to the marine flare. Flare meets 40 CFR 60.18. Destruction Efficiency: 99% for certain compounds up to three carbons, 98% otherwise. Flow monitor is required. Composition or BTU analyzer is required.

Permits Incorporation

Authorization	**Source or Activity**	**Action (Reference/Consolidate/Void)**
PBR 106.261	Facilities (Emission Limitations) - Fugitives	Reference
PBR 106.262	Facilities (Emission and Distance Limitations) - Fugitives	Reference
PBR 106.263	Planned Maintenance, Startup and Shutdown	Reference
PBR 106.355	Pipeline Metering, Purging, and Maintenance	Reference
PBR 106.359	Planned Maintenance, Startup, and Shutdown (MSS) at Oil and Gas Handling and Production Facilities - Abrasive Blasting	Reference
PBR 106.472	Diesel Storage Tanks - EPNs DSLTK6, DSLTK7, DSLTK8	Reference
PBR 106.473	Gasoline Storage Tank - EPN GDFTK3	Reference
PBR 106.478	Diesel Storage Tank - EPN DSLTK5	Reference
PBR 106.511	Portable and Emergency Engines and Turbines - EPNs GEN5, GEN7	Reference
PBR 106.512	Stationary Engines and Turbines - EPNs GEN6, GEN8, GEN9, GEN11, GEN12	Reference

Impacts Evaluation

Was modeling conducted? **Yes.** Type of Modeling: **AERMOD Version 21112**

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

Additional site/land use information: Site is on the north shore of Corpus Christi Bay and surrounded by other industrial sites. The closest residences are 7,600 feet to the west of the site.

I. NAAQS Analysis

Project emissions of SO_2, NOx (as NO_2), CO, and Ozone (O_3) were evaluated in an air quality analysis for potential impacts relative to the National Ambient Air Quality Standards (NAAQS). AERMOD Version 21112 was utilized to model predicted impacts in a refined screening mode. The air dispersion modeling was audited by the TCEQ Air Dispersion Modeling Team (ADMT). Results are summarized as follows:

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

Pollutant	Averaging Time	GLCmax (μg/m^3)	De Minimis (μg/m^3)
SO_2	1-hr	4	7.8
SO_2	3-hr	3	25
SO_2	24-hr	2	5
SO_2	Annual	0.4	1
NO_2	1-hr	80	7.5
NO_2	Annual	8	1
CO	1-hr	339	2000
CO	8-hr	123	500

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

Pollutant	Averaging Time	GLCmax (ppb)	De Minimis (ppb)
O_3	8-hr	3	1

Table 3. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (μg/m^3)	Significance (μg/m^3)
SO_2	24-hr	2	13
NO_2	Annual	8	14
CO	8-hr	123	575

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

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. = [Background + GLCmax] (µg/m^3)	Standard (µg/m^3)
NO_2	1-hr	142	35	177	188
NO_2	Annual	22	4	26	100

Table 5. Total Ozone Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (ppb)	Background (ppb)	Total Conc. = [Background + GLCmax] (ppb)	Standard (ppb)
O_3	8-hr	5	61	66	70

Table 6. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (µg/m^3)	Increment (µg/m^3)
NO_2	Annual	22	25

As indicated in the tables above, the predicted impacts of criteria pollutants are not expected to cause an exceedance of the NAAQS.

II. State Property Line Analysis

Project emissions of SO_2 were evaluated to demonstrate compliance with state standards for net ground-level concentrations, in accordance with 30 TAC Chapter 112. Results are summarized in the table below:

Table 7. Project-Related Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
SO_2	1-hr	4	20.42

As indicated above, the predicted impacts of SO_2 are not expected to cause an exceedance of the state property line standards.

III. Health Effects Analysis

Project emissions of non-criteria pollutants were evaluated for potential impacts in accordance with the TCEQ Modeling and Effects Review Applicability Analysis (MERA) Guidance.

Carbon dioxide, ethane, methane, nitrogen, and propane are classified as simple asphyxiants and do not require a health effects review. These constituents therefore fell out at MERA Step 0. All remaining constituents proceeded to review under MERA Step 2.

Emission rates of xylene, ethanolamine, and triazinetriethanol were below the de minimis thresholds of MERA Step 2 and therefore fell out of the MERA evaluation at that stage.

The following constituents had predicted impacts that were below 10 percent of their respective ESL, and therefore fell out at at project modeling: isobutane, n-butane, isopentane, n-pentane, n-hexane, n-heptane, cyclohexane, cyclopentane, n-decane, ethylbenzene, methylcyclopentane, n-nonane, n-octane, toluene, xylene (-o), xylene (-p), lube oil, and Therminol 55.

Ethylene, benzene, and aMDEA Solution (n-methyldiethanolamine) proceeded to a site-wide modeling analysis. Results of the site-wide analysis are summarized as follows:

Table 8. Minor NSR Site-wide Modeling Results for Health Effects.

Pollutant	CAS#	Averaging Time	GLCmax ($\mu g/m^3$)(1)	ESL ($\mu g/m^3$)
N-Methyldiethanolamine	105-59-9	1-hr	52	96
N-Methyldiethanolamine	105-59-9	Annual	4.16	9.6
Benzene	71-43-2	1-hr	61	170
Benzene	71-43-2	Annual	0.03	4.5
Ethylene	74-85-1	1-hr	137	1400
Ethylene	74-85-1	Annual	1.58	34

Note (1): 1-hr GLCmax values reproduced from ADMT memoranda dated February 1, 2022 and April 27, 2022. Annual GLCmax values for benzene and ethylene based on results reported in Health Effects Modeling Results portion of EMEW dated March 2022. Annual GLCmax value for n-methyldiethanolamine based on multiplying the 1-hr GLCmax value by 0.08 (annual conversion factor).

As indicated above, the predicted impacts of non-criteria pollutants are not expected to cause adverse effects on public health.

For further details on the air quality analysis, please refer to ADMT memoranda dated February 1, 2022 and April 27, 2022 (WCC Content ID Numbers 5929311 and 6052807, respectively).

DRAFT

Project Reviewer	Date	Section Manager	Date
Lyndon Poole, P.E.		Kristyn Campbell	