Special Conditions

Permit Numbers 131769, PSDTX1456, and GHGPSDTX134

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

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

Federal Applicability

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

   A. Subpart A: General Provisions.

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

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

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

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

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

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

   A. Subpart A: General Provisions.

   B. Subpart ZZZZ: The diesel-fired standby generators and fire water pump engines will be subject to National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines. According to 40 CFR § 63.6590(c)(1), compliance with Part 63 is met by compliance with NSPS Subpart IIII.

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

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

Emissions Standards and Operating Specifications

4. Each diesel-fired standby generator and fire water pump engine shall not exceed 100 hours of non-emergency operation per year, on a rolling 12-month basis. Each engine must be equipped with a non-resettable runtime meter.

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

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

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

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

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

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

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

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

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

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

   F. Vent gas (including pilot gas) sent to the marine flare shall not exceed 384 million standard cubic feet per year (MMscf/year), based on a rolling 12-month total. Vent gas (including pilot gas) sent to the ground flare shall not exceed 885 MMscf/year, based on a rolling 12-month total. Additionally, planned MSS vent gas (including pilot gas) sent to the ground flare shall not exceed 4,074 MMscf/year, based on a rolling 12-month total. These limits do not include vent gas sent to the flare systems from emergency or upset conditions.

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

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

    B. The concentration of pollutants in the exhaust gas from the turbines shall not exceed the performance standards listed in the tables below. These performance standards shall apply at all times except during periods of planned MSS. Pollutant concentrations listed in the tables below are in units of ppmvd corrected to 15 percent oxygen (O_2).

Table 1. Refrigeration Compressor Combustion Turbine Performance Standards (EPNs CT-COMP-1 thru CT-COMP-4)

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

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

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

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

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

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

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

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

8. Fuel for the thermal oxidizers (EPNs TO-1 and TO-2) is limited to fuel gas (as identified in the permit application), boil-off gas, pipeline quality natural gas, or a blend of these fuels. Vent gases from the acid gas removal unit, the condensate storage tanks and condensate truck loading operations shall be routed to either of the thermal oxidizers.

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

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

11. All diesel tanks, amine tanks, hot oil and slop oil storage tanks shall be painted white or aluminum and shall utilize a submerged fill pipe. The condensate storage tanks and condensate truck loading operations shall be routed to either of the thermal oxidizers.

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

Ammonia (NH_3) Handling

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

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

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

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

        (1) Locate and isolate the leak, if necessary.
        (2) Commence repair or replacement of the leaking component.
        (3) Use a leak collection or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

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

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

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

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

(1) piping and instrumentation diagram (PID);
(2) a written or electronic database or electronic file;
(3) color coding;
(4) a form of weatherproof identification; or
(5) designation of exempted process unit boundaries.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Initial Determination of Compliance

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

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

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

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

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

   The notice shall include:

   (1) Date for pretest meeting.

   (2) Date sampling will occur.

   (3) Name of firm conducting sampling.

   (4) Type of sampling equipment to be used.

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

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

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

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

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

   (2) For EPNs TO-1 and TO2: NO_x, CO, VOC, SO_2, total particulate matter (PM), and O_2.

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

D. Testing Conditions.

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

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

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

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

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

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

Continuous Demonstration of Compliance

18. The holder of this permit shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) to measure and record the concentrations of NO_x, CO, and diluents (O_2 or carbon dioxide (CO_2)) in the turbine exhaust (EPNs CT-COMP-1, CT-COMP-2, CT-COMP-3, CT-COMP-4, CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, and CT-GEN-9). As an alternative to installing and operating a CEMS, the permit holder may install, calibrate, and maintain a predictive emission monitoring system (PEMS) to measure and record the in-stack concentration of any pollutant required to be monitored by a CEMS from the gas turbines identified above.

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

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

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

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

E. Monitored NO_x and CO concentrations must be corrected and recorded in dimensional units and averaging times corresponding to the emission limitations in Special Condition No. 7 and the MAERT. Compliance for monitored pollutants is based on this data.

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

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

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

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

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

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

Thermal Oxidizers

20. Vent gas from the Acid Gas Removal Unit and other gas streams represented in the air permit application must be directed to either of the two TOs. The TO combustion chamber outlet temperatures and exhaust oxygen concentration for EPNs TO-1 and TO-2 shall be continuously monitored when vent gases are directed to either of the two TOs. The outlet temperature and oxygen concentration must be recorded at least four times an hour (once per quarter of the hour) and averaged hourly for compliance demonstration when vent gases are directed to either of the two TOs. A partial operational hour with greater than 30 minutes of data and two recorded outlet temperature and oxygen concentrations measurements shall count as a valid hour.

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

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

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

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

21. The permit holder shall determine SO_2 emissions from each of the two TOs by utilizing a mass balance of sulfur upstream and downstream of the TOs. The permit holder shall analyze gas sulfur content, at least quarterly, by sampling the gas prior to the first acid gas treatment device and by sampling the gas sulfur content after the last acid gas treatment device prior to being loaded onto a ship. The permit holder may use ASTM methods D1072, D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 to determine sulfur content in the gas streams. Additionally, the permit holder shall monitor total feed gas flow into and out of the Acid Gas Removal Unit on an hourly basis. The flow monitor must receive an in situ third-party certification on an annual basis to demonstrate it will meet ± 5.0% accuracy.

Maintenance, Startup, and Shutdown

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

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

Alternative Means of Compliance (AMOC)

24. Operations of the Ground flare (EPN G-Flare) are subject to the requirements of Alternative Method of Control (AMOC) No. 231, authorized on January 13, 2025. Where applicable, the requirements of the AMOC shall supersede the requirements of this permit **(03/25)**.

Recordkeeping Requirements

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

A. A copy of this permit.

B. Permit application dated April 2015, the August 2015 updates to the original applications and subsequent permit application representations submitted to the TCEQ.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(2) Emissions from the event.

Additional GHG Specific Conditions

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

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

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

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

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

    A. Emissions of CO_2 from each turbine must not exceed 1,060 pounds per megawatt-hour (lbs/MWh) based on generator gross output.

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

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

29. The permit holder shall continuously monitor and record the average hourly fuel consumption of the combustion turbines with individual flow measurements being taken no less frequently than once every 15 minutes. The fuel flow meters shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Fuel flow meters shall be recalibrated annually. The flow meters shall be accurate to ± 5.0 percent of the unit’s maximum flow. Alternatively, fuel flow meters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 are acceptable. Fuel flow meter data shall be automatically recorded with a data acquisition and handling system. Additionally, the permit holder shall monitor and record the gross electric output produced by the combustion turbine electric generators. The monitoring system data shall be used to demonstrate continuous compliance with the performance specifications of Special Condition Nos. 27 and 28 and the emission limits of CO_{2e} in the attached MAERT.

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

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

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

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

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

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

    (1) piping and instrumentation diagram (PID);

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

    (3) color coding;

    (4) a form of weatherproof identification; or

    (5) designation of exempted process unit boundaries.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(3) Permittee shall maintain a file of all records, data measurements, reports and documents related to the fugitive emission sources including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records

relating to compliance with the Monitoring and Quality Assurance and Quality Control procedures outlined in 40 CFR § 98.304.

GHG Continuous Demonstration of Compliance

34. Calculations and recordkeeping shall be the basis for demonstrating continuous compliance with the CO_{2e} emission limits and work practices identified in the permit and on the MAERT. 60 days after achieving commencement of commercial operation of each respective LNG train, but no later than 180 days after commencement of commercial operation of each LNG train, the permit holder shall compare a calendar month's emission rate of CO_{2e} to the limits in the MAERT. The permit holder shall submit a report, no later than 60 days following the time period identified above, to the TCEQ Regional Office identifying whether the data causes any concerns regarding the permit holder's ability to comply with the applicable limitations.

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

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

36. In lieu of the requirements of Special Condition No. 34 for a given turbine or TO, the permit holder may install, calibrate, maintain, and operate a CEMS for CO_2 emission measurements. If a CEMS is installed, the CEMS shall meet the specifications and test procedures for CO_2 emission monitoring system at stationary sources, 40 CFR Part 98; or meet the requirements of 40 CFR Part 60, Appendix B, Performance Specification 3 and follow the monitoring requirements of 40 CFR § 60.13. If a CEMS is installed, the permit holder shall also measure volumetric flow and install a data acquisition and handling system to record all measurements.

GHG Calculation Methodology

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

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

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

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

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

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

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

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

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

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

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

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

(b) A DRE of 99.9% for CH_4.

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

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

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

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

(b) A DRE of 99%

(2) To calculate CO_2 emissions use

(a) The rolling 12-month average CO_2 content

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

(3) To calculate N_2O emissions use

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

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

E. For the diesel-fired standby generators and fire water pump engines (EPNs ENG-GEN-1, ENG-GEN-2, ENG-GEN-3, ENG-FWP-1, ENG-FWP-2, ENG-FWP-3, ENG-FWP-4, and ENG-FWP-5)

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

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

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

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

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

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

G. For Fugitive Equipment Leaks (EPN FUGITIVES)

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

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

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

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

B. Calculate CO_2 emissions utilizing 40 CFR Part 75.

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

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

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

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

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

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

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

Additional GHG Recordkeeping Requirements

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

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

B. Records for each combustion turbine (EPNs CT-COMP-1, CT-COMP-2, CT-COMP-3, CT-COMP-4, CT-GEN-1, CT-GEN-2, CT-GEN-3, CT-GEN-4, CT-GEN-5, CT-GEN-6, CT-GEN-7, CT-GEN-8, and CT-GEN-9) of:

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

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

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

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

(1) Hourly combustion chamber outlet temperature.

(2) Hourly exhaust oxygen content.

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

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

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

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

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

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

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

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

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

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

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

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

Permits 131769, PSDTX1456, and GHGPSDTX134

Attachment A

Incorporated Alternative Method of Control (AMOC) No. 231 Requirements

1. This AMOC Plan Authorization shall apply at the Port Arthur LNG, LLC (PALNG) liquified natural gas (LNG) liquefaction plant and export terminal located near Port Arthur, Jefferson County identified by Regulated Entity Number RN104517826**.** Under Title 30 Texas Administrative Code (TAC) Section 115.910 (§ 115.910) this plan authorizes the pressure-assisted stages of the Wet and Dry multi-point ground flares (MPGF) for use to control emissions from liquid condensate tanks, demethanizer and debutanizer process vents; liquid condensate tanks; and condensate truck loading during routine operations, planned maintenance, start-ups and shut-downs (MSS), as well as unauthorized, unplanned emergency and upset situations.

2. A copy of the AMOC application and the AMOC Plan provisions must be kept on-site or at a centralized location and made available at the request of personnel from the TCEQ or any pollution control agency with jurisdiction. This AMOC authorization is defined by the application received November 7, 2023, and supporting documentation submitted through November 13, 2024.

3. This authorization is granted under § 115.910 for emissions sources regulated by 30 TAC Chapter 115:

   - Subchapter B: General Volatile Organic Compound Sources, Division 1 Storage of VOCs;
   - Subchapter B: General Volatile Organic Compound Sources, Division 2 Vent Gas Control; and
   - Subchapter C: Volatile Organic Compound Transfer Operations, Division 1 Loading and Unloading of VOCs.

   This AMOC shall apply in lieu of the requirements in these state regulations, as applicable. Compliance with this AMOC is independent of the regulated entity's obligation to comply with all other applicable requirements of 30 TAC Chapter 115, TCEQ permits and applicable state and federal law. Compliance with the requirements of this plan does not assure compliance with requirements of an applicable New Source Performance Standard, National Emission Standard for Hazardous Air Pollutants, or an Alternative Means of Emission Limitation (AMEL) and does not constitute approval of alternative standards for these regulations.

4. In accordance with 30 TAC § 115.913(c), all representations submitted for this plan, as well as the provisions listed here, become conditions upon which this AMOC Plan is issued. It is unlawful to vary from the emission limits, control requirements, monitoring, testing, reporting or recordkeeping requirements of this Plan.

   The TCEQ Region may request a performance test if the MPGF systems cannot comply with the requirements of this Plan.

5. The high-pressure MPGF systems are identified as "Ground Flare" (EPN G-FLARE) and are authorized under Permit Nos. 131769, PSDTX1456, GHGPSDTX134 and 158420, PSDTX1572, GHGPSD198 and are subject to this AMOC Plan. When the pressure-assisted burners are operated, compliance is demonstrated following the requirements in paragraph 6 of this AMOC Plan.

6. The Wet and Dry MPGF systems are manufactured by John Zink Hamworthy Combustion (JZHC). The Wet Flare consists of three (3) Indair burners on Stage 1 and a total of 131 LRGO burners on Stages 2 – 5. The Dry Flare includes three (3) Indair burners on Stage 1 and a total of 417 LRGO burners in Stages 2 –9.

The MPGF operates with no assist air or assist steam and shall operate in accordance with the following requirements when regulated materials are routed to the flare systems to achieve 99 % VOC destruction/removal effectiveness (DRE).

A. Operating Requirements: The net heating value of the flare vent gas (NHV_{vg}) must be greater than or equal to 800 British thermal units per standard cubic foot (800 Btu/scf) demonstrated by continuously complying based on a 15-minute block average in accordance with 40 CFR § 63.670(e)(2).

(1) Flare vent gas composition NHV_{vg}. Determine the concentration of individual components or the net heating value in the flare vent gas using the methods in 40 CFR §§ 63.670(j), 63.670(l), and Table 12 of MACT CC, as applicable. Different monitoring methods may be used to determine vent gas composition for different gaseous streams provided the composition or net heating value of all gas streams that contribute to the flare vent gas are determined.

(2) Maximum Flare Tip Velocity (V_{tip}). Calculation of or limits on V_{tip} is not applicable to the HP MPGF burners consistent with 40 CFR § 63.670(d)(3).

(3) Flare Vent Gas Flow Rate Requirements**.** Install, operate, calibrate, and maintain a monitoring system capable of continuously measuring calculating, and recording the cumulative volumetric flow rates in the flare header or headers that feed the flares, and any supplemental fuel used with the flare. The flow rate monitoring systems must comply with 40 CFR § 63.670(i), as applicable.

B. Pilot Flame Requirements: All Indair burners shall be equipped with individual pilots. Each stage of LRGO burners that cross-lights in the pressure-assisted MPGFs must have at least two pilots with at least one continuously lit and capable of igniting all regulated material that is routed to that stage of burners. The MPGF systems shall be operated with a flame present at all times when regulated material is routed to a given stage of high-pressure burners and meet 40 CFR § 63.670(b).

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

D. Stage Valve Position Indicator and Pressure Monitor Requirements: Install and operate pressure monitor(s) on the main flare header, as well as a valve position indicator monitoring system for each staging valve to ensure that the flare operates within the proper range of conditions as specified by the manufacturer and in accordance with 40 CFR § 63.670(d)(3).

E. Closed Vent Capture Systems. Streams vented to the MPGF must be routed through a closed vent system that is not open to the atmosphere and is configured of piping, ductwork, connections, and flow inducing devices that transport gas or vapor from any emission source or point to a control device.

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

(1) General.

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

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

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

(2) <u>Composition or Net Heating Values</u>. Install, operate, calibrate, and maintain a monitoring system specified in (a). Alternatively, the net heating value of the flare vent gas may be monitored following the method specified in (b).

a. A gas chromatograph, or gas chromatograph / mass spectrometer, or mass spectrometer may be used to determine NHVvg as specified in 40 CFR § 63.670(j)(1). Component properties determinations must follow 40 CFR § 63.670(l)(1) and Table 12 of MACT CC. The system used to determine compositional analysis shall follow 40 CFR § 63.671(e) and (f), as applicable. The monitor shall meet the accuracy and calibration requirements of Table 13 of MACT CC.

b. A calorimeter capable of continuously measuring, calculating, and recording the net heating value, NHVvg, present in the flare vent gas according to 40 CFR § 63.670(j)(3). The monitor shall meet the accuracy and calibration requirements of Table 13 of MACT CC.

(3) <u>Flow Rates</u>.

a. Different flow monitoring methods may be used to measure different gaseous streams and assist media streams provided that 40 CFR §63.670(i) is followed.

b. The measurement location must be selected following Table 13 of MACT CC.

c. All flow monitors shall meet the accuracy and calibration requirements of Table 13 of MACT CC.

(4) <u>Pilots.</u>

a. The pilot flame continuous monitoring must meet 40 CFR § 63.670(b).

b. Loss of pilot flame is determined by and must meet 40 CFR §§63.670(b) and records must follow 40 CFR § 63.655(i)(9)(i).

c. A video camera that meets 40 CFR §63.670(h)(2) may be used to demonstrate compliance.

(5) <u>Pressure</u>. Any pressure monitor must meet the accuracy and calibration requirements of Table 13 of MACT CC.

(6) <u>Temperature.</u> Any temperature monitor must meet the accuracy and calibration requirements of Table 13 of MACT CC.

G. Recordkeeping Requirements

Records shall follow requirements in 40 CFR § 63.655(i).

H. Emission Determinations.

Calculations of hourly and annual emissions to determine compliance with the MAERT limitations shall be determined and recorded using the monitoring data collected pursuant to this AMOC Plan applying the best data of the parameters measured during each 15-minute block period and the appropriate emission factors based on the approach represented in the Permits. Annual emissions shall be calculated by the end of the current month for the previous rolling 12-month period. To calculate CH_4 and CO_2 emissions, use the methodology in 40 CFR § 98.233(n)(4) – (6).