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

TO: Office of Chief Clerk **Date:** February 13, 2023

FROM: Contessa Gay
Staff Attorney
Environmental Law Division

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

Applicant:	Entergy Texas, Inc.
Permit Nos.:	166032, GHGPSDTX210, PSDTX1598
Program:	Air
Docket No.:	TCEQ Docket No. 2023-0164-AIR

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

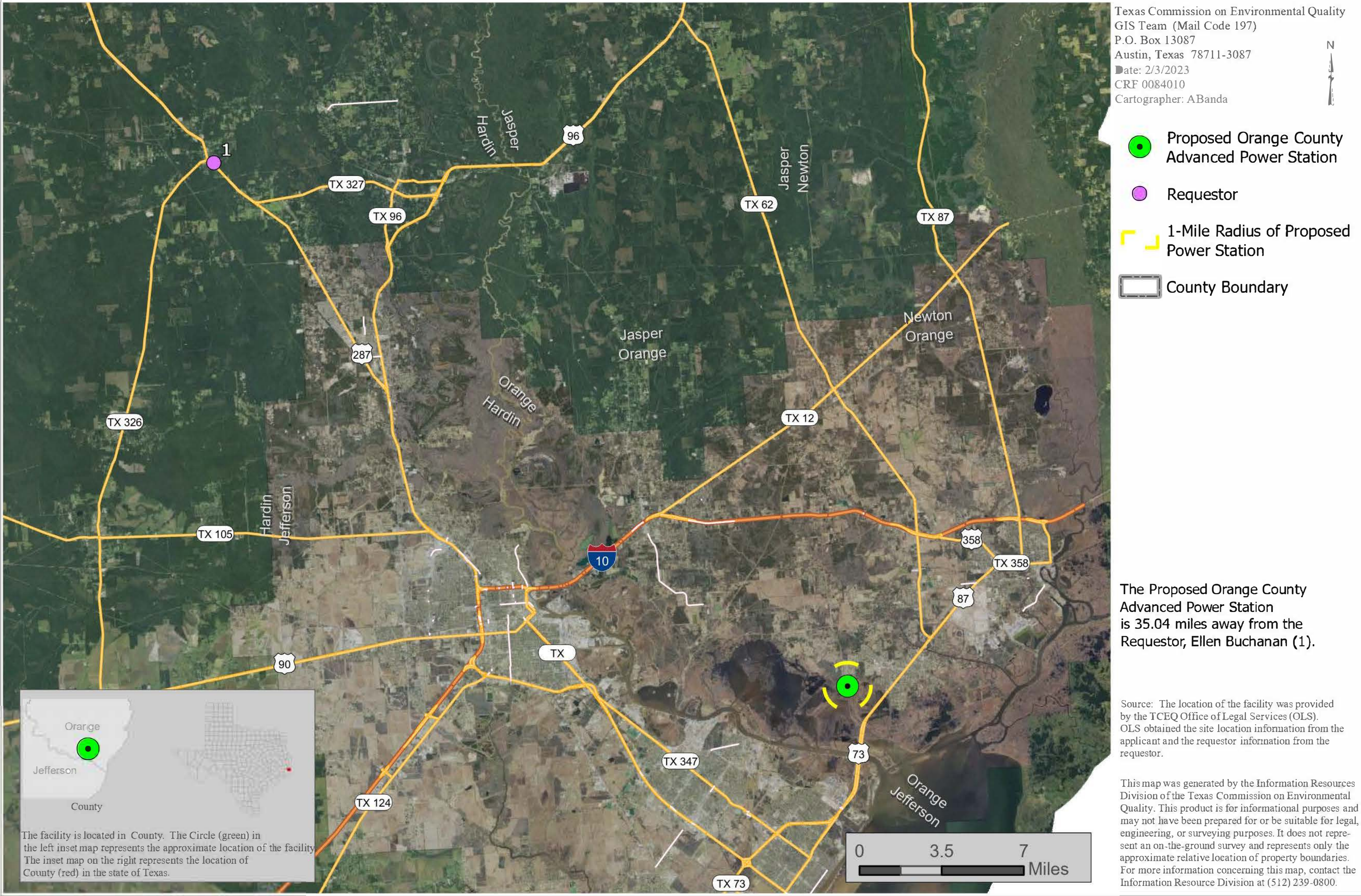
- A Map with the proposed plant location and hearing requestor address
- The final draft of the permit special conditions
- The Emission Sources – Maximum Allowable Emission Rates
- The Air Quality Analysis Modeling Audit (containing the health effects review)
- The Compliance History Report
- The Construction Permit Source Analysis & Technical Review

Entergy Texas, Inc. (166032, GHGPSDTX210, PSDTX75958)

Map Requested by TCEQ Office of Legal Services
for Commissioners' Agenda

Protecting Texas by Reducing and Preventing Pollution

Texas Commission on Environmental Quality
GIS Team (Mail Code 197)
P.O. Box 13087
Austin, Texas 78711-3087
Date: 2/3/2023
CRF 0084010
Cartographer: ABanda



The facility is located in County. The Circle (green) in the left inset map represents the approximate location of the facility. The inset map on the right represents the location of County (red) in the state of Texas.

The Proposed Orange County Advanced Power Station is 35.04 miles away from the Requestor, Ellen Buchanan (1).

Source: The location of the facility was provided by the TCEQ Office of Legal Services (OLS). OLS obtained the site location information from the applicant and the requestor information from the requestor.

This map was generated by the Information Resources Division of the Texas Commission on Environmental Quality. This product is for informational purposes and may not have been prepared for or be suitable for legal, engineering, or surveying purposes. It does not represent an on-the-ground survey and represents only the approximate relative location of property boundaries. For more information concerning this map, contact the Information Resource Division at (512) 239-0800.

Special Conditions

Permit Numbers 166032, PSDTX1598, and GHGPSDTX210

1. This permit covers only those sources of emissions listed in the attached table entitled “Emission Sources - Maximum Allowable Emission Rates” (MAERT), including planned maintenance, startup, and shutdown (MSS) activities, and those sources are limited to the emission limits on that table and other conditions specified in this permit.

Federal Applicability

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

   A. Subpart A, General Provisions.

   B. Subpart Dc, Small Industrial-Commercial-Institutional Steam Generating Units.

   C. Subpart IIII, Stationary Compression Ignition Internal Combustion Engines.

   D. Subpart KKKK, Stationary Combustion Turbines.

   E. Subpart TTTT, Greenhouse Gas Emissions for Electric Generating Units.

3. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories in 40 CFR Part 63:

   A. Subpart A, General Provisions.

   B. Subpart YYYY, Stationary Combustion Turbines.

   C. Subpart ZZZZ, Stationary Reciprocating Internal Combustion Engines.

   D. Subpart DDDDD, Industrial, Commercial, and Institutional Boilers and Process Heaters.

Emissions Standards, Operating Specifications, and Fuel Specifications

4. This permit authorizes two natural gas fired combustion generators (CTGs) to operate in combined cycle mode [Emission Point Numbers (EPNs): OCPS1A and OCPS1B]. Additionally, these CTGs are also authorized to co-fire up to 30% hydrogen gas by volume. Both turbines are Mitsubishi model M501JAC turbines, each with an average heat input of 3,756.2 million British thermal units per hour (MMBtu/hr) and each with a rated nominal capacity of 428 gross megawatts (MW) at ISO Conditions (59 °F, 1 bar, and 60% relative humidity). Each CTG will have a heat recovery steam generator (HRSG) with no supplemental duct firing. Each HRSG supplies steam to a single steam turbine which drives a third electric generator with a rated nominal capacity of 387 gross MW at ISO Conditions. Therefore, the total rated nominal capacity is 1,243 gross MW at ISO Conditions.

5. The combined turbine emissions identified as Emission Point No. OCPS1A and OCPS1B, shall not exceed the following concentrations in parts per million by volume, dry basis (ppmvd) at 15% oxygen (O_2), except during periods of planned maintenance, startup, and shutdown (MSS):

Pollutant	Concentration	Averaging Time
Nitrogen oxide (NO_x)	2.0	24-hr rolling average
Carbon monoxide (CO)	2.0	24-hr rolling average
Ammonia (NH_3)	7.0	24-hr rolling average

A. In order for each CTG to enter Environmental Compliance Mode, the CTG load shall exceed the following percent for at least 3 minutes (for the specified ambient temperature ranges):

Minimum Turbine Load %	Ambient Temperature Range (deg. F)
50	10.0 – 93.0
55	93.1 – 106.1

B. Planned startup events for each turbine are excluded from the above concentration limits. Each startup period shall not exceed six hours and is defined as the period that begins when fuel is introduced and a combustion flame has been established in the CTG. The startup period ends when signals are received indicating that the CT is in Environmental Compliance Mode, ammonia injection is in service, and the startup emissions have purged through the continuous emissions monitoring system (CEMS).

C. Planned shutdown events for each turbine are excluded from the above concentration limits. Each shutdown period shall not exceed one hour and is defined as the period that begins when signals are received demonstrating that the CT is no longer in Environmental Compliance Mode and that the ammonia injection is no longer in service for purposes of an intended shutdown. The shutdown period ends when a signal is received that the CTG has flamed out.

D. Emissions from maintenance activities (Attachment B) shall be excluded from the above concentration limits.

E. Emissions during reduced load operations defined as operational loads below 60% of full load shall be excluded from the above concentration limits. Emissions during reduced load operation shall not exceed the normal hourly emission rates in the MAERT.

F. NO_X emissions during transitional load operations, defined as a CTG ramp rate greater than 5 MW per minute (MW/min), may be excluded from the 24-hr average concentration limit if:

(1) the 24-hour average concentration is above 2.0 ppmvd at 15% O_2, and

(2) the qualifying NO_X concentration occurs during a 24-hour period where the turbine ramp rate exceeds 5 MW/minute during at least one hour in that period.

(3) The emissions from transitional load operations shall not exceed the MSS hourly emission rates in the MAERT.

6. Authorized fuel for EPNs OCPS1A, OCPS1B shall be limited to pipeline-quality, sweet natural gas containing no more than 0.44 grains total sulfur per 100 dry standard cubic feet (dscf). Additionally, EPNs OCPS1A and OCPS1B are authorized to be co-fired with up to 30% hydrogen gas by volume with natural gas.

7. The Water Bath Heaters (EPNs OCPSNGWBHA, OCPSNGWBHB, OCPSH2WBHA, and OCPSH2WBHB) shall be fired with natural gas containing no more than 0.44 grains of total sulfur per 100 dry standard cubic feet (dscf).

Opacity / Visible Emissions

8. Except during MSS activities, the opacity shall not exceed five percent (5%) averaged over a six-minute period from each CTG stack. During planned MSS activities, the opacity shall not exceed fifteen percent (15%) for each CTG stack over a six-minute period (or other applicable opacity limit specified in 30 TAC § 111.111(a)(1)). Each determination shall be made by first observing for visible emissions while each gas turbine 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. A certified opacity reader is not required for these visible emission observations. 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. Contributions from uncombined water shall not be included in determining compliance with this condition.

   Visible emission observations shall be performed and recorded quarterly for each turbine while the facilities are in operation, unless the emission unit is not operating for the entire calendar quarter. If the opacity exceeds 5% during normal operations or 15% during MSS activities, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one (1) week of first observation.

Cooling Towers

9. The cooling tower (EPN OCPS-CTW) shall be operated and monitored in accordance with the following:

   A. Cooling towers shall each be equipped with drift eliminators having manufacturer's design assurance of 0.0005% drift or less. Drift eliminators shall be maintained and inspected at least annually. The permit holder shall maintain records of all inspections and repairs.

   B. Total dissolved solids (TDS) shall not exceed 1,056 parts per million by weight (ppmw). Dissolved solids in the cooling water drift are considered to be emitted as PM, PM_{10}, and $PM_{2.5}$ as represented in the permit application calculations.

   C. Cooling water shall be sampled at least once per week for TDS.

   D. Cooling water sampling shall be representative of the cooling tower feed water and shall be conducted using approved methods.

      (1) The analysis method for TDS shall be EPA Method 160.1, ASTM D5907, and SM 2540 C [SM - 19th edition of Standard Methods for Examination of Water]. Water samples should be capped upon collection and transferred to a laboratory area for analysis.

      (2) Alternate sampling and analysis methods may be used to comply with D(1) with written approval from the TCEQ Regional Director. If approved by the TCEQ Regional Director, the permit holder shall submit a permit application to incorporate the

alternative sampling and analysis method into the permit within 2 months of the date of written approval.

(3) Records of all instrument calibrations and test results and process measurements used for the emission calculations shall be retained.

E. Emission rates of PM, PM_{10} and $PM_{2.5}$ shall be calculated using the measured TDS and the ratio or correlation of TDS to conductivity measurements, the design drift rate and the daily maximum and average actual cooling water circulation rate for the short term and annual average rates. Alternately, the design maximum circulation rate may be used for all calculations. Emission records shall be updated monthly.

Emergency Generators

10. The 2,922-horsepower (hp) emergency standby generator (EPN OCPS-EMGEN), the 327-hp emergency firewater pump (EPN OCPS-FWP), and the two 755-hp emergency fire protection generators (EPN OCPS1AFPGE and OCPS1BFPGE) are each limited to 100 hours of non-emergency operation per year, on a calendar year basis. Each must be equipped with a non-resettable runtime meter.

11. The fuel for these emergency generators (EPNs OCPS-EMGEN, OCPS-FWP, OCPS1AFPGE, and OCPS1BFPGE) shall be limited to diesel fuel containing no more than 15 ppm sulfur by weight.

12. Records of the number of non-emergency hours of operation for the emergency generators (EPNs OCPS-EMGEN, OCPS-FWP, OCPS1AFPGE, and OCPS1BFPGE) shall be maintained at the plant site for at least five years and be made available to representatives of the TCEQ upon request.

Ammonia Handling

13. In the event of a release of the NH_3 from the liquid fill line, pressure vessel due to over pressurization, process line to the selective catalytic reduction (SCR) system, or the vapor return lines from the vaporizer, or any other accidental release of NH_3, the permit holder shall follow the mitigation procedures set out in the permit application and follow the risk management plan required by 40 CFR Part 68 that will be complete before startup of the plant (and subsequent updates per 40 CFR §68.190). The risk management plan shall be submitted to the TCEQ Office of Air, Air Permits Division prior to the date this site first exceeds a threshold quantity of aqueous ammonia.

Storage Tanks

14. Storage tank throughput and service shall be limited to the following:

EPN	Tank Identifier	Service	Fill/Withdrawal rate (gallons/hour)	Rolling 12 Month Throughput (gallons)
OCPSTK9	Standby Generator Engine Diesel Tank	Diesel	4,325	150,000

OCPSTK18	Cooling Water Sodium Hypochlorite Storage Tank	Bleach	8,000	240,024
OCPSTK19	Sulfuric Acid Tank	Sulfuric acid	8,000	20,148

15. Additional storage tank (EPNs OCPSTK11, OCPSTK23, and OCPSTK24) service is limited to storing diesel fuel.

16. Storage tanks are subject to the following requirements:

    A. Except for labels, logos, etc. not to exceed 15 percent of the tank total surface area, uninsulated tank exterior surfaces exposed to the sun shall be white, unpainted aluminum, or stainless steel. The Cooling Water Sodium Hypochlorite Storage Tank (EPN OCPSTK18) uninsulated exterior surfaces exposed to the sun shall be polyethylene. Storage tanks must be equipped with permanent submerged fill pipes.

    B. The permit holder shall maintain a record of tank throughput for the previous month and the past consecutive 12 month period for tanks EPNs OCPSTK9 and OCPSTK18-19.

Physical Inspections of Piping, Valves, Pumps, and Compressors in contact with Diesel – 28PI

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

    A. 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.

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

    C. 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. Non-accessible valves, as defined in Title 30 Texas Administrative Code (30 TAC) Chapter 115, shall be identified in a list to be made available upon request.

    D. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter.

    E. Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

    F. All piping components shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

    G. Damaged or leaking valves, connectors, compressor seals, and pump seals found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. 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, 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.

At the discretion of the TCEQ Executive Director or designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

H. Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) upon request.

Piping, Valves, Pumps, and Compressors in contact with Natural Gas and Ammonia – 28AVO

18. Except as may be provided for in the Special Conditions of this permit, the following requirements apply to the above-referenced equipment:

    A. Audio, olfactory, and visual checks for leaks within the operating area shall be made daily.

    B. Immediately, but no later than one hour upon detection of a leak, plant personnel shall take at least one of the following actions:

        (1) Isolate the leak.

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

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

19. Date and time of each inspection shall be noted in the operator's log or equivalent. Records shall be maintained at the plant site of all repairs and replacements made due to leaks. These records shall be made available to representatives of the Texas Commission on Environmental Quality (TCEQ) upon request.

Initial Determination of Compliance

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

21. 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 the gas turbines. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods to be determined during the pretest meeting.

    The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his or her expense. 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/equivalent procedure proposals for 40 CFR Part 60 testing which must have EPA approval shall be submitted to the TCEQ Regional Director.

    A. The appropriate TCEQ Regional Office shall be notified not less than 45 days prior to sampling. The notice shall include:

(1) Proposed 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) Description of any proposed deviation from the sampling procedures specified in this permit or TCEQ/EPA sampling procedures.

(7) Procedure/parameters to be 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 the test reports. The TCEQ Regional Director must approve any deviation from specified sampling procedures.

B. Air contaminants emitted from the gas turbines to be tested for include (but are not limited to) CO, NO_X, VOC, NH_3, SO_2, PM_{10}, and O_2. As noted below, fuel sampling using the methods and procedures of 40 CFR § 60.4415 may be conducted in lieu of stack sampling for SO_2.

C. Fuel sampling using the methods and procedures of 40 CFR § 60.4415 may be conducted in lieu of stack sampling for SO_2 or the permit holder may be exempted from fuel monitoring of SO_2 as provided under 40 CFR § 60.4365. 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.

D. Each CTG shall be tested at or above ninety percent (90%) of maximum load operations. 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.

E. Sampling shall occur within 60 days after achieving the maximum operating rate at which CTG will be operated, but no later than 180 days after initial start-up of each unit and at such other times as may be required by the TCEQ Executive Director. Requests for additional time to perform sampling shall be submitted to the appropriate regional office.

F. Copies of the final sampling report shall be forwarded to the offices below within 60 days after sampling is completed. Sampling reports shall comply with the attached provisions entitled “Chapter 14, Contents of Sampling Reports” of the TCEQ Sampling Procedures Manual. The reports shall be distributed as follows:

One copy to the appropriate TCEQ Regional Office.

One copy to each local air pollution control program.

Continuous Demonstration of Compliance

22. The permit holder shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to monitor and record the NO_X, CO, and O_2 from each gas turbine exhaust stack (EPNs OCPS1A and OCPS1B).

A. The NO_x and O_2 CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B, or an acceptable alternative. The requirements of 40 CFR Part 75, Appendices A and B are deemed an acceptable alternative to the performance specifications and quality assurance requirements of 40 CFR Part 60. Data used to meet the requirements of this permit shall not include substitute data values derived from the missing data procedures in subpart D of 40 CFR Part 75, nor shall the data have been bias adjusted according to the procedures of 40 CFR Part 75.

B. The CO CEMs shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable performance specifications in 40 CFR Part 60, Performance Specification No. 4. The CO CEMS shall meet the applicable quality assurance requirements specified in 40 CFR Part 60, Appendix F, except that cylinder gas audits (CGA) conducted in all four quarters may be used in lieu of the annual relative accuracy test audit. Quarterly CGAs shall be conducted at least 60 days apart. A CGA is not required in any quarter in which the CT operates less than 168 hours.

C. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, § 5.2.3, CGA exceedances of ±15% accuracy, and any CEMS downtime shall be reported semiannually to the TCEQ Regional Director, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Manager.

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

E. The monitoring data shall be reduced to hourly average values at least once every day, using a minimum of four equally-spaced data points from each one-hour period. At least two (2) valid data points shall be generated during an hourly period in which zero and span is performed. The valid hourly average data from the CEMS shall be recorded in units of parts per million by volume dry at 15% oxygen (ppmvd at 15% O_2) and averaged over the specified averaging time, and the resulting average shall be used to determine compliance with the concentration limits of Special Condition No. 5.

The resulting average concentration shall be converted to units of pounds per million BTU and multiplied by the hourly average natural gas fuel or blended fuel (natural gas with up to 30% hydrogen gas by volume) consumption data (in million BTU) required by Part I of this Special Condition to determine compliance with the hourly emission rate limits of the MAERT. Pounds per hour data from each CTG/HRSG stack shall be summed monthly to tons per year and used to determine compliance with the annual emission limits of the MAERT.

F. All monitoring data and quality-assurance data shall be maintained by the source for a period of five (5) years and shall be made available to the TCEQ Executive Director or designated representative upon request. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

G. The TCEQ Regional Office shall be notified at least 30 days prior to any required relative accuracy test audit (RATA) in order to provide them the opportunity to observe the testing.

H. If any emission monitor fails to meet specified performance, it shall be repaired or replaced as soon as reasonably possible.

I. The holder of this permit shall additionally install, calibrate, maintain, and operate continuous monitoring systems to monitor and record the average hourly natural gas or blended fuel (natural gas with up to 30% hydrogen gas by volume) consumption of each CTG. The permit holder shall comply with the initial certification and quality assurances as specified in 40 CFR Part 75. The systems shall be accurate to ±5.0 percent of the gas turbine maximum flow.

J. Quality-assured (or valid) data must be generated when the CTGs are operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in hours) that the CTGs operated over the previous rolling 12-month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded. Options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ Regional Manager.

23. The NH_3 concentration in each CTG Stack (EPNs: OCPS1A and OCPS1B) shall be tested or calculated according to one of the methods listed below and shall be tested or calculated according to the frequency listed below. Testing for NH_3 slip is only required on days when the NH_3 injection to the SCR unit is in operation.

A. The holder of this permit may install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NH_3. The NH_3 concentrations shall be corrected and reported in accordance with Special Condition No. 5.

B. As an approved alternative, the NH_3 slip may be measured using a sorbent or stain tube device specific for NH_3 measurement in the 5 to 10 ppm range. The frequency of sorbent or stain tube testing shall be daily for the first 60 days of operation, after which, the frequency may be reduced to weekly testing if operating procedures have been developed to prevent excess amounts of NH_3 from being introduced in the SCR unit and when operation of the SCR unit has been proven successful with regard to controlling NH_3 slip. Daily sorbent or stain tube testing shall resume when the catalyst is within 30 days of its useful life expectancy. These results shall be recorded and used to determine compliance with Special Condition No. 5.

C. If the sorbent or stain tube testing indicates an ammonia slip concentration exceeds 7 ppm for a consecutive one-hour period or the average of one or more sorbent or stain tube tests in an hour, the permit holder shall begin NH_3 testing by either the Phenol Nitroprusside Method, the Indophenol Method, or the EPA Conditional Test Method (CTM) 27 on a quarterly basis, in addition to the weekly sorbent of stain tube testing. The quarterly testing shall continue until such time as the SCR unit catalyst is replaced; or if the quarterly testing indicates NH_3 slip is less than 7 ppm, the Phenol-Nitroprusside/Indophenol/CTM 27 tests may be suspended until sorbent/stain tube testing again indicate 7 ppm NH3 slip or greater. These results shall be recorded and used to determine compliance with Special Condition No. 5.

D. As an approved alternative to sorbent or stain tube testing or an NH_3 CEMS, the permit holder may install and operate a second NOx CEMS probe located upstream of the stack NOx 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 NOx reduction efficiency on the SCR unit. These results shall be recorded and used to determine compliance with Special Condition No. 5.

E. As an approved alternative to sorbent or stain tube testing, NH_3 CEMS, or a second NO_x CEMS, the permit holder may install and operate a dual stream system of NOx CEMS at the exit of the SCR. One of the exhaust streams would be routed, in an unconverted state, to one NOx CEMS and the other exhaust stream would be routed through a NH_3 converter to convert NH_3 to NOx and then to a second NOx CEMS. The NH_3 slip concentration shall be calculated from the delta between the two NOx CEMS readings (converted and unconverted). These results shall be recorded and used to determine compliance with Special Condition No. 5.

F. Any other method used for measuring NH_3 slip shall require prior approval from the TCEQ Regional Office.

Planned Maintenance, Startup, and Shutdown

24. Attachment A identifies the inherently low emitting MSS activities that may be performed at the plant. Emissions from activities identified in Attachment A shall be considered to be equal to the potential to emit represented in the permit application. The estimated emissions from the activities listed in Attachment A must be revalidated annually. This revalidation shall consist of the estimated emissions for each type of activity and the basis for that emission estimate.

25. Compliance with the emissions limits for planned maintenance activities identified in Attachment B may be demonstrated as follows.

A. For each pollutant emitted during planned maintenance activities whose emissions are measured using a CEMS, the permit holder shall for each calendar month compare the pollutant's short-term (hourly) emissions as measured by the CEMS to the applicable short-term planned MSS emissions limit in the MAERT.

B. For each pollutant emitted during planned maintenance activities whose emissions occur through a stack, the permit holder shall for each calendar month determine the total emissions of the pollutant.

C. The performance of each planned MSS activity and the emissions associated with it shall be recorded and include at least the following information:

(1) the type of planned MSS activity and the reason for the planned activity;

(2) the date and time of the MSS activity and its duration; and

(3) the estimated quantity of each air contaminant, or mixture of air contaminants, emitted with the data and methods used to determine it. The emissions shall be estimated using the methods identified in the permit application, consistent with good engineering practice.

D. Sum all emissions from planned maintenance activities on a 12-month rolling basis for each EPN to show compliance with the MAERT.

Commissioning Period

26. The performance specifications and concentration limits of Special Condition No. 5 and 30 and the MAERT apply beginning with commencement of operations following completion of construction. Construction is completed based on the date included in the notification required by 30 TAC 116.115 (b)(2)(A). These limits do not apply during periods of commissioning, during which the

permit holder conducts initial operational and contractual testing and tuning to ensure the safe, efficient, and reliable operation of the electric generating unit. This one-time period shall not exceed 180 days following completion of construction.

Greenhouse Gas Emissions

27. Permit holders must keep records sufficient to demonstrate compliance with 30 Texas Administrative Code § 116.164. If construction, a physical change or a change in 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 method of operation does not require authorization under 30 TAC §116.164(a). If there is construction, a physical change or 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.

28. Monitoring, quality assurance/quality control requirements, emission calculation methodologies, record keeping, and reporting requirements related to Greenhouse Gas (GHG) emissions shall adhere to the applicable requirements in 40 CFR Part 98 and in this permit.

29. The permit holder 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.

30. The CTGs shall not exceed a combined 814.7 pounds of carbon dioxide per megawatt hour (lb CO2/MW-hr) on a rolling 12-month average for both turbines, based on gross total plant generator output. MSS activities as defined in Special Condition No. 5.B, 5.C, 24, and Maintenance Activities as defined in Attachment A and B are excluded.

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

    A. For EPN OCPS-CBFUG, 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 Rule for Electrical Transmission and Distribution Equipment Use, 40 CFR Part 98, Subpart DD. The total SF_6 inventory of the circuit breakers shall not exceed 2,684 lb with leak detection.

    B. The circuit breakers shall be equipped with a low pressure alarm and low pressure lockout. The SF6 leak detection system shall be able to detect a leak of at least 1 lb per year.

    C. As soon as practicable following the 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.

Recordkeeping Requirements

32. The following records shall be kept at the plant for the life of the permit. All records required in this permit shall be made available at the request of personnel from the Texas Commission on Environmental Quality (TCEQ), EPA, or any local air pollution control agency with jurisdiction:

    A. A copy of this permit.

    B. Permit application received July 29, 2021, and subsequent representations submitted to the TCEQ.

    C. A complete copy of the testing reports and records of the initial performance testing completed to demonstrate initial compliance.

    D. Stack sampling results or other air emissions testing (other than CEMS data) that may be conducted on units authorized under this permit after the date of issuance of this permit.

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

    A. The CEMS data of NO_x, CO, and O_2 emissions from EPNs OCPS1A and OCPS1B to demonstrate compliance with the emission rates listed in the MAERT and Special Condition No. 5.

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

    C. Records of dates and times for startups and shutdowns of the CTGs.

    D. Records of the amount of natural gas and hydrogen gas fired monthly in each of the CTGs.

    E. Records of the hours of operation of the emergency engines and firewater pump to demonstration compliance with Special Condition No. 10.

    F. Records of visible emissions, opacity observations, and any corrective action taken to demonstrate compliance with Special Condition No. 8.

    G. Cooling tower records to demonstrate compliance with Special Condition No. 9.

    H. Records of AVO checks, maintenance performed to any piping and valves or other equipment as required by Special Condition No. 17, 18, and 19.

    I. Records of monitored or calculated MSS emissions to demonstrate compliance with Special Condition No. 25.

    J. Records of GHG emissions, and how they were determined, to show compliance with Special Condition Nos. 27 to 31.

Emission Reduction Conditions

34. This permit is conditioned on the completion of the following emission reduction project represented in the Table 3F, Project Contemporaneous Changes submitted September 17, 2021 and later updated on September 28, 2021 for the amendment with the Form PI-1 dated July 29, 2021.

Permit 45604: Unit 1 Retirement (FIN B1: EPNs 1A and 1B) of 404.06 tpy NO_x, 7.89 tpy CO, 13.86 tpy VOC, 1.56 tpy SO_2, 19.15 tpy PM, 19.15 tpy PM_{10}, 19.15 tpy $PM_{2.5}$, and 312,562 tpy CO_2e.

This reduction of emissions shall occur not later than the commencement of operation of these gas turbine facilities. The permit holder shall maintain records of these emission reductions and provide access and/or copies upon request to the TCEQ Executive Director, or representatives, or any local air pollution control program having jurisdiction. Construction of these facilities must commence as defined in 40 CFR § 52.21(b)(9) no later than five years after all emission reductions identified in the netting analysis are actually accomplished, or the above reductions are no longer creditable and the permit is automatically void.

Date: TBD

Permit 166032, PSDTX1598, and GHGPSDTX210

Attachment A

Inherently Low Emitting Activities

Activity	EPN	Emissions					
		NO_x	CO	VOC	PM	SO_2	NH_3
On-line turbine washing	OCPSMSSFUG				x		
Miscellaneous PM filter maintenance[1]	OCPSMSSFUG				x		
Catalyst handling and maintenance[2]	OCPSMSSFUG				x		
CEMS analyzer calibration	OCPSMSSFUG	x	x				
Small equipment and fugitive component repair/replacement in VOC and NH_3 service[3]	OCPSMSSFUG			x			x

Dated: TBD

[1] Includes, but is not limited to: baghouse filters and combustion turbine air intake filters

[2] Includes, but is not limited to: replacement, cleaning, activation, and deactivation of SCR and oxidation catalysts.

[3] Includes, but is not limited to: (1) repair/replacement of pumps, compressors, valves, pipes, flanges, transport lines, filters/screens in natural gas, fuel oil, diesel oil, ammonia, lube oil, and gasoline service; (2) vehicle and mobile equipment maintenance that may involve small VOC emissions, such as oil changes and transmission/hydraulic system service; (3) off-line NO_x control device maintenance including aqueous ammonia systems.

Permit 166032, PSDTX1598, and GHGPSDTX210

Attachment B

MSS Activity Summary

Activities	EPN	Emissions					
		NO_x	CO	VOC	PM	SO_2	NH_3
Combustion unit tuning[4]	OCPS1A, OCPS1B, OCPS1-CAP	x	x	x	x	x	x
Gaseous fuel venting[5]	OCPSMSSFUG			x			

Date: TBD

[4] Includes, but is not limited to: leak operability checks (e.g. turbine overspeed test, troubleshooting), seasonal tuning, islanding testing, and balancing.

[5] Includes, but is not limited to: venting prior to pipeline pigging and meter proving.

Emission Sources - Maximum Allowable Emission Rates

Permit Number 166032 and PSDTX1598

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**	
			lbs/hour	**TPY (4)**
OCPS1A	OCPS Combined Cycle Unit 1A (Turbine)	NO_x	28.99	--
		NO_x (MSS) (6)	278.00	--
		CO	17.65	--
		CO (MSS) (6)	9409.00	--
		VOC	10.11	--
		VOC (MSS) (6)	3209.00	--
		SO_2 (6)	5.48	--
		PM (6)	30.40	--
		PM_{10} (6)	30.40	--
		$PM_{2.5}$ (6)	30.40	--
		H_2SO_4 (6)	8.39	--
		NH_3 (6)	44.65	--
		HAPs (6)	2.09	--
OCPS1B	OCPS Combined Cycle Unit 1B (Turbine)	NO_x	28.99	--
		NO_x (MSS) (6)	278.00	--
		CO	17.65	--
		CO (MSS) (6)	9409.00	--
		VOC	10.11	--
		VOC (MSS) (6)	3209.00	--
		SO_2 (6)	5.48	--
		PM (6)	30.40	--
		PM_{10} (6)	30.40	--
		$PM_{2.5}$ (6)	30.40	--
		H_2SO_4 (6)	8.39	--

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		NH_3 (6)	44.65	--
		HAPs (6)	2.09	--
OCPS1-CAP	OCPS Combined Cycle Unit 1 Emission Cap	NO_x	--	318.37
		CO	--	2424.38
		VOC	--	994.03
		SO_2	--	40.48
		PM	--	172.00
		PM_{10}	--	172.00
		$PM_{2.5}$	--	172.00
		H_2SO_4	--	63.85
		NH_3	--	329.91
		HAPs	--	17.75
OCPS-CTW	OCPS Cooling Tower	PM	0.60	2.65
		PM_{10}	0.49	2.13
		$PM_{2.5}$	0.01	0.06
OCPS-EMGEN	OCPS Standby Generator	NO_x	29.16	1.46
		CO	16.81	0.84
		VOC	1.58	0.08
		SO_2	0.04	<0.01
		PM	0.96	0.05
		PM_{10}	0.96	0.05
		$PM_{2.5}$	0.96	0.05
		HAPs	0.03	<0.01
OCPS-FWP	OCPS Emergency Fire Pump	NO_x	2.04	0.10
		CO	1.87	0.09
		VOC	0.11	0.01
		SO_2	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		PM	0.11	0.01
		PM_{10}	0.11	0.01
		$PM_{2.5}$	0.11	0.01
		HAPs	0.01	<0.01
OCPS1AFPGE	OCPS CT1A Fire Protection Generator	NO_x	7.54	0.38
		CO	4.34	0.22
		VOC	0.41	0.02
		SO_2	0.01	<0.01
		PM	0.25	0.01
		PM_{10}	0.25	0.01
		$PM_{2.5}$	0.25	0.01
		HAPs	0.01	<0.01
OCPS1BFPGE	OCPS CT1B Fire Protection Generator	NO_x	7.54	0.38
		CO	4.34	0.22
		VOC	0.41	0.02
		SO_2	0.01	<0.01
		PM	0.25	0.01
		PM_{10}	0.25	0.01
		$PM_{2.5}$	0.25	0.01
		HAPs	0.01	<0.01
OCPSNGWBHA	OCPS Fuel Gas NG Water Bath Heater Stack A	NO_x	0.34	1.47
		CO	0.32	1.38
		VOC	0.04	0.19
		SO_2	0.01	0.04
		PM	0.06	0.26
		PM_{10}	0.06	0.26
		$PM_{2.5}$	0.06	0.26

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
		HAPs	0.02	0.07
OCPSNGWBHB	OCPS Fuel Gas NG Water Bath Heater Stack B	NO_x	0.34	1.47
		CO	0.32	1.38
		VOC	0.04	0.19
		SO_2	0.01	0.04
		PM	0.06	0.26
		PM_{10}	0.06	0.26
		$PM_{2.5}$	0.06	0.26
		HAPs	0.02	0.07
OCPSH2WBHA	OCPS Fuel Gas H2 Water Bath Heater Stack A	NO_x	0.28	1.23
		CO	0.26	1.15
		VOC	0.04	0.16
		SO_2	0.01	0.04
		PM	0.05	0.22
		PM_{10}	0.05	0.22
		$PM_{2.5}$	0.05	0.22
		HAPs	0.01	0.05
OCPSH2WBHB	OCPS Fuel Gas H2 Water Bath Heater Stack B	NO_x	0.28	1.23
		CO	0.26	1.15
		VOC	0.04	0.16
		SO_2	0.01	0.04
		PM	0.05	0.22
		PM_{10}	0.05	0.22
		$PM_{2.5}$	0.05	0.22
		HAPs	0.01	0.05
OCPS-NGFUG	OCPS Natural Gas Fugitive Emissions (5)	VOC	0.01	0.05
		HAPs	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
OCPSAMMFUG	OCPS Ammonia Fugitive Emissions (5)	NH_3	0.08	0.37
OCPSDSLFUG	OCPS Diesel Fugitive Emissions (5)	VOC	0.10	0.45
		HAPs	<0.01	0.01
OCPS-LOV	OCPS Lube Oil Vents	VOC	0.03	0.13
OCPSMSSFUG	OCPS Maintenance Activities	NO_x	<0.01	<0.01
		CO	<0.01	<0.01
		VOC	60.87	6.94
		PM	2.68	0.08
		PM_{10}	2.67	0.08
		$PM_{2.5}$	2.66	0.08
		NH_3	0.01	<0.01
		HAPs	0.30	0.04
OCPSTK1	GT 1A Control Oil Tank	VOC	0.01	<0.01
OCPSTK2	GT 1B Control Oil Tank	VOC	0.01	<0.01
OCPSTK3	NG Condensate Fuel Drain Tank 1	VOC	3.18	0.04
OCPSTK4	NG Condensate Fuel Drain Tank 2	VOC	3.18	0.04
OCPSTK5	NG Condensate Fuel Drain Tank 3	VOC	3.18	0.04
OCPSTK6	ST Control Oil Tank	VOC	0.02	<0.01
OCPSTK7	CT 1A Lube Oil Reservoir	VOC	0.37	0.01
OCPSTK8	CT 1B Lube Oil Reservoir	VOC	0.37	0.01
OCPSTK9	Standby Generator Engine Diesel Tank	VOC	0.35	0.01
OCPSTK10	Standby Generator Lube Oil Tank	VOC	<0.01	<0.01
OCPSTK11	Emergency Firewater Pump Engine Diesel Tank	VOC	0.04	<0.01
OCPSTK12	ST Main Oil Tank	VOC	0.43	0.01
OCPSTK13	Boiler Feed Pump Lube Oil Reservoir 1	VOC	<0.01	0.02
OCPSTK14	Boiler Feed Pump Lube Oil Reservoir 2	VOC	<0.01	0.02
OCPSTK15	Boiler Feed Pump Lube Oil Reservoir 3	VOC	<0.01	0.02

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
OCPSTK16	Boiler Feed Pump Lube Oil Reservoir 4	VOC	<0.01	0.02
OCPSTK17	Oil Water Separator	VOC	0.22	0.04
OCPSTK18	Cooling Water Sodium Hypochlorite Storage Tank	NaClO	0.14	<0.01
OCPSTK19	Sulfuric Acid Tank	H_2SO_4	<0.01	<0.01
OCPSTK20	CTG 1A Seal Oil Vacuum Tank	VOC	<0.01	<0.01
OCPSTK21	CTG 1B Seal Oil Vacuum Tank	VOC	<0.01	<0.01
OCPSTK22	STG Seal Oil Vacuum Tank	VOC	<0.01	<0.01
OCPSTK23	CTG 1A FP Generator Engine Diesel Tank	VOC	0.04	<0.01
OCPSTK24	CTG 1B FP Generator Engine Diesel Tank	VOC	0.04	<0.01
OCPSTK25	CTG 1A FP Generator Engine Lube Oil Tank	VOC	<0.01	<0.01
OCPSTK26	CTG 1B FP Generator Engine Lube Oil Tank	VOC	<0.01	<0.01

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
CO - carbon monoxide
HAP - hazardous air pollutant as listed in § 112(b) of the Federal Clean Air Act or Title 40 Code of Federal Regulations Part 63, Subpart C
H_2SO_4 - sulfuric acid
NH_3 - ammonia
NaClO - sodium hypochlorite
(4) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period.
(5) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.
(6) Planned maintenance, startup and shutdown (MSS) for all pollutants are authorized even if not specifically identified as MSS. During any clock hour that includes one or more minutes of planned MSS or transition load operation events that pollutant's maximum hourly emission rate shall apply during that clock hour.

Date: TBD

Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPSDTX210

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)
OCPS1-CAP	OCPS Combined Cycle Unit 1 Emission Cap	CO_2 (5)	4045655.00
		CH_4 (5)	75.02
		N_2O (5)	7.50
		CO_2e	4049766.00
OCPS-EMGEN	OCPS Standby Generator	CO_2 (5)	152.44
		CH_4 (5)	0.01
		N_2O (5)	<0.01
		CO_2e	152.96
OCPS-FWP	OCPS Emergency Fire Pump	CO_2 (5)	16.71
		CH_4 (5)	<0.01
		N_2O (5)	<0.01
		CO_2e	16.77
OCPS1AFPGE	OCPS CT1A Fire Protection Generator	CO_2 (5)	29.58
		CH_4 (5)	<0.01
		N_2O (5)	<0.01
		CO_2e	29.69
OCPS1BFPGE	OCPS CT1B Fire Protection Generator	CO_2 (5)	29.58
		CH_4 (5)	<0.01
		N_2O (5)	<0.01
		CO_2e	29.69
OCPSNGWBHA	OCPS Fuel Gas NG Water Bath Heater Stack A	CO_2 (5)	4,303.83
		CH_4 (5)	0.08
		N_2O (5)	0.01
		CO_2e	4,308.27
OCPSNGWBHB	OCPS Fuel Gas NG Water Bath Heater Stack B	CO_2 (5)	4,303.83
		CH_4 (5)	0.08

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates
			TPY (4)
		N_2O (5)	0.01
		CO_2e	4,308.27
OCPSH2WBHA	OCPS Fuel Gas H2 Water Bath Heater Stack A	CO_2 (5)	3,586.52
		CH_4 (5)	0.07
		N_2O (5)	0.01
		CO_2e	3,590.23
OCPSH2WBHB	OCPS Fuel Gas H2 Water Bath Heater Stack B	CO_2 (5)	3,586.52
		CH_4 (5)	0.07
		N_2O (5)	0.01
		CO_2e	3,590.23
OCPS-NGFUG	OCPS Natural Gas Fugitive Emissions (5)	CO_2 (5)	0.14
		CH_4 (5)	2.50
		CO_2e	62.57
OCPS-CBFUG	OCPS Circuit Breaker Fugitives	SF_6 (5)	0.01
		CO_2e	152.99
OCPSMSSFUG	OCPS Maintenance Activities	CO_2 (5)	19.04
		CH_4 (5)	346.93
		CO_2e	8,692.27

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) CO_2 - carbon dioxide
N_2O - nitrous oxide
CH_4 - methane
SF_6 - sulfur hexafluoride
CO_2e - carbon dioxide equivalents based on the following Global Warming Potentials (1/2015):
CO_2 (1), N_2O (298), CH_4(25), SF_6 (22,800)
(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.

Date: TBD

TCEQ Interoffice Memorandum

To: Huy Pham
Mechanical/Coatings Section

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

From: Ahmed Omar, P.E.
ADMT

Date: April 21, 2022

Subject: Air Quality Analysis Audit - Entergy Texas, Inc. (RN102513041)

1. Project Identification Information

Permit Application Number: 166032
NSR Project Number: 331768
ADMT Project Number: 7798
County: Orange
Published Map: \\tceq4avmgisdata\GISWRK\APD\MODEL PROJECTS\7798\7798.pdf

Air Quality Analysis: Submitted by ERM, January 2022, on behalf of Entergy Texas, Inc. Additional information and modeling were provided March and April 2022.

2. Report Summary

The air quality analysis (AQA) 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 CO and $PM_{2.5}$ exceed the respective de minimis concentrations and require a full impacts analysis. The De Minimis analysis modeling results for PM_{10} indicate that the project is below the respective de minimis concentrations and no further analysis is required.

The $PM_{2.5}$ and ozone De Minimis levels are the EPA recommended De Minimis levels. The use of the EPA recommended De Minimis levels is sufficient to conclude that a proposed source will not cause or contribute to a violation of an ozone and $PM_{2.5}$ NAAQS or $PM_{2.5}$ PSD increments based on the analyses documented in EPA guidance and policy memoranda[1].

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

[1] 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 ($\mu g/m^3$)

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	De Minimis ($\mu g/m^3$)
PM_{10}	24-hr	3	5
PM_{10}	Annual	0.3	1
$PM_{2.5}$ (NAAQS)	24-hr	2.4	1.2
$PM_{2.5}$ (NAAQS)	Annual	0.25	0.2
$PM_{2.5}$ (Increment)	24-hr	2.9	1.2
$PM_{2.5}$ (Increment)	Annual	0.27	0.2
CO	1-hr	10872	2000
CO	8-hr	548	500

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

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

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's Guideline on Air Quality Models (GAQM). Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind the MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.06 $\mu g/m^3$ and 0.002 $\mu g/m^3$, respectively. Since the combined direct and secondary 24-hr and annual $PM_{2.5}$ impacts are above the De minimis levels, a full impacts analysis is required.

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	0.8	1

The applicant performed an O_3 analysis as part of the PSD AQA. The applicant evaluated project emissions of O_3 precursor emissions (NO_x and VOC). For the project NO_x and VOC emissions, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. Using data associated with the Harris County source, the applicant estimated an 8-hr O_3 concentration of 0.8 ppb. When the estimates of ozone concentrations from the project emissions are added together, the results are less than the De Minimis level.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that 24-hr PM_{10} 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)
PM_{10}	24-hr	3	10
CO	8-hr	548	575

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

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

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 482450021 located at 2200 Jefferson Dr., Port Arthur, Jefferson County. The applicant calculated a three-year average (2018-2020) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value (23 µg/m^3). The applicant calculated a three-year average (2018-2020) of the annual concentrations for the annual value (9.1 µg/m^3). This monitor is reasonable based on the applicant’s land use comparison, quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site, and the proximity of the monitor to the project site (approximately seven miles to the south). The background values were also used in the NAAQS analysis

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).

Background concentrations for O_3 were obtained from the EPA AIRS monitor 483611001 at 2700 Austin Ave., West Orange, Orange County. A three-year average (2018-2020) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis (66 ppb). The use of this monitor for a background concentration of ozone 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 and the proximity of the monitor to the project site (approximately 8 miles to the northeast).

C. National Ambient Air Quality Standard (NAAQS) Analysis

The De Minimis analysis modeling results indicate that CO and $PM_{2.5}$ 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/m³)	Background (µg/m³)	Total Conc. = [Background + GLCmax] (µg/m³)	Standard (µg/m³)
$PM_{2.5}$	24-hr	6.4	23	29.4	35
$PM_{2.5}$	Annual	0.5	9.1	9.6	12
CO	1-hr	8703	1714	10417	40000
CO	8-hr	1378	1444	2822	10000

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

The annual $PM_{2.5}$ GLCmax is the maximum five-year average of the annual concentrations determined for each receptor.

The 1-hr and 8-hr CO GLCmax are the maximum high, second high predicted concentrations across five years of meteorological data.

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 482450021 located at 2200 Jefferson Dr., Port Arthur, Jefferson County. The applicant calculated a three-year average (2018-2020) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value. The applicant calculated a three-year average (2018-2020) of the annual concentrations for the annual value. This monitor is reasonable based on the applicant's land use comparison, quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site, and the proximity of the monitor to the project site (approximately seven miles to the south). Also, the applicant considered the monitors in the vicinity of the project and used the monitor with the highest background concentrations.

Background concentrations for CO were obtained from the EPA AIRS monitor 482011035 located at 9525 ½ Clinton Dr., Houston, Harris County. The high, second-high 1-hr concentration from 2018-2020 was used for the 1-hr value. The high, second-high 8-hr concentration from 2018-2020 was used for the 8-hr value. The use of the monitor is reasonable since the monitor is located in the Houston Ship Channel with greater surrounding emissions than the project site.

As stated above, to evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. Using data associated with the Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.06 µg/m³ and 0.002 µg/m³, respectively. When these estimates are added to the GLCmax listed in Table 4 above, the results are less than the NAAQS.

D. Increment Analysis

The De Minimis analysis modeling results indicate that 24-hr and annual $PM_{2.5}$ exceed the respective de minimis concentrations and require a PSD increment analysis.

Table 5. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Increment ($\mu g/m^3$)
$PM_{2.5}$	24-hr	8.7	9
$PM_{2.5}$	Annual	2	4

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

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

E. Additional Impacts Analysis

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

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

The H_2SO_4 24-hr maximum predicted concentration of 11 $\mu g/m^3$ occurred at the western property line. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 50 km from the proposed sources, in the direction of the Breton Wilderness Class I area is 0.32 $\mu g/m^3$. The Breton Wilderness Class I area is an additional 420 km from the edge of the receptor grid. Therefore, emissions of H_2SO_4 from the proposed project are not expected to adversely affect the Breton Wilderness Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than de minimis levels at a distance of 20 km from the proposed sources in the direction the Breton Wilderness Class I area. The Breton Wilderness Class I area is an additional 450 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Breton Wilderness Class I area.

F. Minor Source NSR and Air Toxics Analysis

Table 6. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Standard ($\mu g/m^3$)
SO_2	1-hr	365	817

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
H_2SO_4	1-hr	18	50
H_2SO_4	24-hr	11	15

Table 7. Modeling Results for Minor NSR De Minimis

Pollutant	Averaging Time	GLCmax (µg/m^3)	De Minimis (µg/m^3)
SO_2	1-hr	1.5	7.8
SO_2	3-hr	3	25
SO_2	24-hr	1	5
SO_2	Annual	0.04	1
NO_2	1-hr	65	7.5
NO_2	Annual	0.98	1

The 1-hr SO_2 and 1-hr NO_2 GLCmax are based on the highest five-year average of the maximum predicted concentrations determined for each receptor. The 3-hr, 24-hr, and annual SO_2 and annual NO_2 GLCmax are the maximum predicted concentrations associated with five years of meteorological data.

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

The justification for selecting the EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels was based on the assumptions underlying EPA's development of the 1-hr NO_2 and 1-hr SO_2 De Minimis levels. As explained in EPA guidance memoranda[2,3], the EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 1-hr NO_2 and 1-hr SO_2 NAAQS.

Table 8. Total Concentrations for Minor NSR NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. = [Background + GLCmax] (µg/m^3)	Standard (µg/m^3)
NO_2	1-hr	85	60	145	188

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

A background concentration for NO_2 was obtained from the EPA AIRS monitor 482450009 at 1086 Vermont Ave., Beaumont, Jefferson County. The three-year average (2018-2020) of the 98th percentile of the annual distribution of the daily maximum 1-hr concentrations

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

was used for the 1-hr value. 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 and land use comparison. Also, the applicant considered the monitors in the vicinity of the project and used the monitor with the highest background concentrations.

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

Pollutant	CAS#	Averaging Time	GLCmax ($\mu g/m^3$)	GLCmax Location	ESL ($\mu g/m^3$)
ammonia	7664-41-7	1-hr	155	Eastern Property Line	180
benzene	71-43-2	1-hr	146	Northern Property Line	170
benzene	71-43-2	Annual	1.4	Northern Property Line	4.5
diesel fuel	68334-30-5	1-hr	97	Eastern Property Line	1000
formaldehyde	50-00-0	1-hr	3	Eastern Property Line	15
C15-30 petroleum lubricating oils, hydrotreated neutral oil-based	72623-86-0	1-hr	43	Eastern Property Line	1000
polycyclic aromatic hydrocarbons	130498-29-2	1-hr	0.2	Eastern Property Line	0.5
sodium hypochlorite	7681-52-9	1-hr	21	Eastern Property Line	50
cadmium	7440-43-9	1-hr	0.02	Eastern Property Line	5.4
cadmium	7440-43-9	Annual	0.0004	Northern Property Line	0.0033

The GLCmax locations are listed in Table 9 above.

3. Model Used and Modeling Techniques

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

Two operating scenarios were modeled for the combustion turbines: Steady-State Operations (normal operations) and Start-up and Shutdown Operations (SU/SD). The maximum predicted concentrations from the worst-case scenarios are reported in the tables above.

For full NAAQS and increment analyses, the applicant evaluated only SU/SD scenario; however, since the results from SIL analyses for the two scenarios are comparable, the applicant's approach was reasonable.

For normal operations, the turbines can operate at multiple load cases (i.e.100% load, 75% load, etc.) using two types of fuel: 100% natural gas and hybrid fuel consisting of up to 30% hydrogen by volume with natural gas. For each load case/fuel type, emissions and stack parameters were provided for several ambient temperature conditions. Each of these cases and temperature conditions were evaluated and used to determine the worst-case normal operating scenario for each averaging period. The scenarios with the worst-case impacts for each averaging period were used in the modeling demonstrations.

For the SU/SD operations, a total of fifteen different SU/SD scenarios, representing various combinations of cold, warm, and hot starts as well as shutdown, were considered. The SU/SD scenarios were grouped into two general classes: the 1X1 scenarios represent the class in which only one of the turbines is in transient mode, while the second turbine is operating in steady state (normal) mode. In the 2X1 scenarios, both turbines are operating in transient mode with designating one or the other turbine as lead or lag. In all scenarios the emission rates were evaluated for each pollutant.

Three types of startup were considered: cold, warm, and hot as well as shutdown. Each of these activities was characterized by duration, emission rates, and stack parameters. To account for all averaging periods, two sets of SU/SD emission rates were modeled: maximum and average. The 1-hr averaging times were evaluated using maximum SU/SD emissions. For the 3, 8, and 24-hr averaging time, an average emission rate was used. When the SU/SD duration is less than the pollutant averaging time, the turbine was assumed operating in normal operations after the SU/SD period has expired.

The applicant conducted the 1-hr and annual NO_2 modeling demonstration using the plume volume molar ratio method (PVMRM) model option to account for conversion of NO_x to NO_2. For all on-site sources, except Unit 4 boiler, the default NO_2/NO_x in-stack ratio of 0.5 was used. For Unit 4 boiler, NO_2/NO_x in-stack ratio of 0.2 was used. For all off-property sources, the default NO_2/NO_x in-stack ratio of 0.2 was used. In addition, the default NO_x to NO_2 equilibrium ratio of 0.9 was used with the PVMRM model option.

The monitored ozone concentrations for the Tier 3 analysis were obtained from the EPA AIRS monitor 483611001 located at 2700 Austin Ave., West Orange, Orange County. The use of this monitor with the PVMRM model option is reasonable based on the close proximity of the monitor relative to the project site (approximately eight miles to the northeast of the Project site). The hourly ozone data were pared in time with the modeled hours of meteorological data. Approximately 96% of the monitoring data were complete from the above monitor. Missing values in the hourly ozone data were filled with the computed hour-and-month maximum values from the same station. For example, missing value on January 1 for hour 2 was filled with a maximum concentration that occurs on hour 2 during the month of January in the 2014-2018 period. The applicant did not provide justification for using ozone monitoring data from 2014-2018; however, the ADMT conducted test modeling using an ozone “super day” with 2020 monitoring data and determined that the applicant’s approach will not affect the overall modeling results.

A. Land Use

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

B. Meteorological Data

Surface Station and ID: Port Arthur, TX (Station #: 12917)
Upper Air Station and ID: Lake Charles, LA (Station #: 3937)
Meteorological Dataset: 2016 for health effects and state property line analyses; 2014-2018 for all other analyses
Profile Base Elevation: 4.9 meters

C. Receptor Grid

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

D. Building Wake Effects (Downwash)

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

Tanks TANK2 and TANK3 were included in the downwash analysis with heights of 2.74 meters, while the reported heights are 4.6 and 7 meters, respectively. However, these tanks are located approximately 500 meters from the nearest property line and the overall modeling results will not be affected.

Some modeled structures in the existing Sabine plant, building IDs UNIT4A-B, UNIT5A-E, BLDG2, UNIT1A-C, UNIT3A-B and UNIT3E, appear to be process areas and the associated piping components. It is unclear if these areas will present a significant obstruction to wind flow. However, these structures are located approximately 500 meters from the nearest property line and the overall modeling results will not be affected.

The layout of Building IDs EMHOUSE and FPHOUSE were not consistent with the layout in the plot plan. However, the applicant provided test modeling and verified that this inconsistency will not affect the overall modeling results.

The 1-hr H_2SO_4 analyses was evaluated without downwash parameters; however, since the closest point source to the property line is located approximately 130 meters from the property line, this discrepancy will not affect the overall modeling results.

4. Modeling Emissions Inventory

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

For full NAAQS and increment analyses, the modeled locations and parameters for several off-property sources from recent permitting actions were not consistent with the reported locations and source parameters; however, given the locations of the GLCmax relative to the locations of these sources (approximately more than 5 km), it is unlikely this will affect the overall modeling results.

For CO normal operations with 100% Natural Gas fuel scenario, the modeled emission rates for the turbines were greater than the reported emission rates. This is conservative.

For CO full NAAQS analyses, the on-site sources, Model IDs B3A, B3B, B4, and B5, were modeled with locations slightly different than the reported locations; however, since the modeled locations were closer to the property line, this will not affect the overall modeling results.

For 1-hr NO_2 full NAAQs analyses, the modeled emission rates for source IDs FGWBH1 – 2 were lower than the reported emission rates; however, ADMT conducted test modeling using the reported emission rates and verified that this inconsistency will not affect the overall modeling results.

For the 1-hr SO_2 and 1-hr NO_2 de Minimis and NAAQS analyses, emissions from the emergency engine (EPN OCPS-EMGEN), emergency fire pump (EPN OCPS-FWP), and fire protection generators (EPNs OCPS1AFPGE and OCPS1BFPGE) were modeled with an annual average emission rate, consistent with EPA guidance for evaluating intermittent emissions. Emissions from each source were represented to occur for no more than 100 hours per year.

For the 1-hr NO_2 de Minimis and NAAQS analyses, emissions from cold and warm starts for the lag turbine (Model IDs 21CSLG1A, 21CSLG1B, 21WSLG1A, and 21WSLG1B) were evaluated with an annual average emission rate, consistent with EPA guidance for evaluating intermittent emissions. Emissions from cold and warm starts were represented to occur for no more than 27 and 67 hours per year, respectively. In the 1-hr NO_2 de Minimis and NAAQS analyses, the abovementioned sources were modeled with the average emission rates which are greater than the annualized emission rates.

For the 1-hr NO_2 de Minimis and NAAQS analyses, the applicant did not provide justification for modeling average emission rates for hot starts for the lag turbine (Model IDs 21HSLG1A and 21HSLG1B) rather than using the maximum emission rates; however, ADMT conducted test modeling using the maximum emission rates and verified that the applicant's approach will not affect the overall modeling results.

For the 1-hr NO_2 NAAQS analyses, emissions from the emergency engines (EPNs TELCOMEG, U12&3EMER, and U4&5EMER), and emergency diesel engine (EPN FIREPUMP), were modeled with an annual average emission rate, consistent with EPA guidance for evaluating intermittent emissions. Emissions from each source were represented to occur for no more than 100 hours per year.

For 3-hr, 8-hr, and 24-hr analyses, emissions from the emergency engine (EPN OCPS-EMGEN), emergency fire pump (EPN OCPS-FWP), and fire protection generators (EPNs OCPS1AFPGE and OCPS1BFPGE) were modeled with the corresponding average emission rates representing one hour of operation per day.

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

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Compliance History Report

Compliance History Report for CN603282054, RN102513041, Rating Year 2021 which includes Compliance History (CH) components from September 1, 2016, through August 31, 2021.

Customer, Respondent, or Owner/Operator: CN603282054, Entergy Texas, Inc. **Classification:** SATISFACTORY **Rating:** 0.15

Regulated Entity: RN102513041, SABINE PLANT **Classification:** SATISFACTORY **Rating:** 0.11

Complexity Points: 26 **Repeat Violator:** NO

CH Group: 06 - Electric Power Generation

Location: 1000 POWER HOUSE RD ORANGE, TX 77630-0102, ORANGE COUNTY

TCEQ Region: REGION 10 - BEAUMONT

ID Number(s):

AIR OPERATING PERMITS PERMIT 69
AIR OPERATING PERMITS ACCOUNT NUMBER OC0013O
AIR NEW SOURCE PERMITS PERMIT 2329
AIR NEW SOURCE PERMITS PERMIT 45604
AIR NEW SOURCE PERMITS AFS NUM 4836100007
AIR NEW SOURCE PERMITS EPA PERMIT PSDTX719
AIR NEW SOURCE PERMITS REGISTRATION 71069
AIR NEW SOURCE PERMITS ACCOUNT NUMBER OC0013O
AIR NEW SOURCE PERMITS REGISTRATION 100815
AIR NEW SOURCE PERMITS REGISTRATION 136042
AIR NEW SOURCE PERMITS EPA PERMIT PSDTX1598
AIR NEW SOURCE PERMITS PERMIT 166032
AIR NEW SOURCE PERMITS EPA PERMIT GHGPSDTX210
PETROLEUM STORAGE TANK REGISTRATION REGISTRATION 54894
WASTEWATER PERMIT WQ0000336000
WASTEWATER EPA ID TX0006696
AIR EMISSIONS INVENTORY ACCOUNT NUMBER OC0013O
INDUSTRIAL AND HAZARDOUS WASTE EPA ID TXD980626030
INDUSTRIAL AND HAZARDOUS WASTE SOLID WASTE REGISTRATION # (SWR) 31274

Compliance History Period: September 01, 2016 to August 31, 2021 **Rating Year:** 2021 **Rating Date:** 09/01/2021

Date Compliance History Report Prepared: January 31, 2023

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

Component Period Selected: July 29, 2016 to July 29, 2021

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

Name: TCEQ Staff Member **Phone:** (512) 239-0270

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:
N/A

B. Criminal convictions:
N/A

C. Chronic excessive emissions events:
N/A

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

Item 1	August 16, 2016	(1365573)
Item 2	September 16, 2016	(1372274)

Item 3	October 20, 2016	(1378451)
Item 4	November 01, 2016	(1370617)
Item 5	November 19, 2016	(1384410)
Item 6	December 09, 2016	(1375811)
Item 7	December 19, 2016	(1390548)
Item 8	January 16, 2017	(1397164)
Item 9	February 17, 2017	(1404048)
Item 10	February 21, 2017	(1394261)
Item 11	March 17, 2017	(1411148)
Item 12	April 19, 2017	(1417651)
Item 13	May 17, 2017	(1425240)
Item 14	June 19, 2017	(1431243)
Item 15	July 10, 2017	(1423339)
Item 16	July 25, 2017	(1439852)
Item 17	August 21, 2017	(1443541)
Item 18	September 19, 2017	(1450167)
Item 19	October 16, 2017	(1455987)
Item 20	October 23, 2017	(1447407)
Item 21	October 24, 2017	(1447586)
Item 22	November 07, 2017	(1448071)
Item 23	November 16, 2017	(1461467)
Item 24	December 12, 2017	(1467847)
Item 25	January 25, 2018	(1460578)
Item 26	January 29, 2018	(1464831)
Item 27	January 30, 2018	(1460604)
Item 28	March 16, 2018	(1490455)
Item 29	April 18, 2018	(1493692)
Item 30	May 17, 2018	(1500610)
Item 31	June 18, 2018	(1507727)
Item 32	July 02, 2018	(1498023)
Item 33	July 17, 2018	(1514045)
Item 34	August 13, 2018	(1506952)
Item 35	August 15, 2018	(1520107)
Item 36	August 16, 2018	(1510961)
Item 37	September 13, 2018	(1527271)
Item 38	October 15, 2018	(1533629)
Item 39	November 12, 2018	(1541464)
Item 40	December 14, 2018	(1545248)
Item 41	January 19, 2019	(1559719)
Item 42	February 04, 2019	(1525369)
Item 43	February 18, 2019	(1559717)
Item 44	March 18, 2019	(1559718)
Item 45	April 17, 2019	(1571845)
Item 46	May 19, 2019	(1583300)
Item 47	June 18, 2019	(1583301)
Item 48	July 16, 2019	(1571569)
Item 49	July 17, 2019	(1593158)
Item 50	August 19, 2019	(1599504)
Item 51	September 17, 2019	(1606409)
Item 52	October 15, 2019	(1598493)
Item 53	October 17, 2019	(1613255)
Item 54	November 18, 2019	(1619069)
Item 55	December 18, 2019	(1626421)
Item 56	January 18, 2020	(1634062)
Item 57	February 18, 2020	(1640681)
Item 58	March 18, 2020	(1647201)
Item 59	April 17, 2020	(1653537)
Item 60	April 29, 2020	(1639326)
Item 61	April 30, 2020	(1644859)
Item 62	May 19, 2020	(1660124)

Item 63	June 12, 2020	(1651527)
Item 64	June 17, 2020	(1666628)
Item 65	June 19, 2020	(1652645)
Item 66	July 19, 2020	(1673585)
Item 67	August 18, 2020	(1680361)
Item 68	September 17, 2020	(1686929)
Item 69	October 16, 2020	(1678227)
Item 70	November 18, 2020	(1712518)
Item 71	December 17, 2020	(1712519)
Item 72	January 07, 2021	(1678231)
Item 73	January 18, 2021	(1712520)
Item 74	February 18, 2021	(1725573)
Item 75	March 15, 2021	(1725574)
Item 76	April 17, 2021	(1725575)
Item 77	May 17, 2021	(1740089)
Item 78	June 17, 2021	(1747593)
Item 79	June 18, 2021	(1723855)
Item 80	July 19, 2021	(1751725)

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: 09/30/2020 (1693276)

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

F. Environmental audits:

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

Construction Permit
Source Analysis & Technical Review

Company	**Entergy Texas Inc**	Permit Numbers	**166032, GHGPSDTX210, and PSDTX1598**
City	**Orange**	Project Number	**331768**
County	**Orange**	Regulated Entity Number	**RN102513041**
Project Type	**Initial**	Customer Reference Number	**CN603282054**
Project Reviewer	**Huy Pham**	Received Date	**July 29, 2021**
Site Name	**Orange County Advanced Power Station**		

Project Overview

Entergy Texas, Inc. (ETI) proposes construction of a natural gas-fired combined cycle turbine power plant called the Orange County Advanced Power Station (OCPS). The OCPS project is located within the property boundary of the existing ETI Sabine Plant in Orange County, Texas. Maintenance, Startup, and Shutdown activities will be authorized under this permit.

Emission Summary

Air Contaminant	Proposed Allowable Emission Rates (tpy)*
PM	175.78
PM_{10}	175.26
$PM_{2.5}$	173.19
VOC	1,002.83
NO_X	326.10
CO	2,430.82
SO_2	40.68
NH_3	330.29
H_2SO_4	63.86
GHG as CO_2e	4,074,700

*For an initial permit, the baseline actual emissions are zero. Therefore, the values represented here also represent the project changes at major sources (baseline actual emissions to proposed allowable emissions).

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	January 30, 2023
Site rating & classification:	0.00 / High
Company rating & classification:	0.12 / 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	8/4/2021

Requirement	Date
Date 1st notice published	8/14/2021
Publication Name: The Orange Leader	
Pollutants: aqueous ammonia, carbon monoxide, hazardous air pollutants, hydrogen, nitrogen oxides, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, sulfur dioxide and sulfuric acid mist	
Date 1st notice Alternate Language published	8/15/2021
Publication Name (Alternate Language): El Perico	
1st public notice tearsheet(s) received	8/18/2021
1st public notice affidavit(s) received	8/20/2021
1st public notice certification of sign posting/application availability received	9/15/2021
SB709 Notification mailed	8/9/2021; re-issued 4/25/2022
Date 2nd notice published	06/29/2022
Publication Name: The Orange Leader	
Pollutants: carbon monoxide, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, sulfuric acid mist, greenhouse gases, nitrogen oxides, hazardous air pollutants, sulfur dioxide, aqueous ammonia, and hydrogen	
Date 2nd notice published (Alternate Language)	06/29/2022
Publication Name (Alternate Language): El Perico	
2nd public notice tearsheet(s) received	7/13/2022
2nd public notice affidavit(s) received	7/13/2022
2nd public notice certification of sign posting/application availability received	08/10/2022

Public Interest

Number of comments received	241
Number of meeting requests received	471
Number of hearing requests received	471
Date meeting held	08/01/2022
Date response to comments filed with OCC	11/29/2022
Date of SOAH hearing	

Federal Rules Applicability

Requirement	
Subject to NSPS?	**Yes**
Subparts **A, Dc, IIII, KKKK & TTTT**	
Subject to NESHAP?	**No**
Subparts **N/A**	
Subject to NESHAP (MACT) for source categories?	**Yes**
Subparts **A, YYYY, ZZZZ** & **DDDDD**	
Nonattainment review applicability: The site is located in Orange County, which is in attainment for all criteria pollutants.	

PSD review applicability:
Since the proposed plant is located within the boundary of an existing PSD major source site owned and operated by Entergy (The Sabine Plant), the project emissions were compared to the PSD major modification Significant Emission Rate (SER). The project increases for CO, NOx, SO_2, VOC, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG are above the applicable SERs. Following netting however, the project is PSD for CO, VOC, PM, PM_{10}, $PM_{2.5}$, H_2SO_4, and GHG.

The netting window was defined as November 2017 (five years prior to planned start of construction in November 2022) through April 2025 (planned start of commissioning as the start of operation for the project). The planned retirement of Unit 1 [Facility Identification Number (FIN) B1, Emission Point Numbers (EPNs) 1A/1B] at the Sabine Plant (NSR Permit 45604) will occur during netting window and represent a creditable contemporaneous decrease. The boiler in Unit 1 is planned to be permanently retired prior to start of operation of the OCPS project. No other projects fall within the netting window.

	CO (tpy)	NO_x (tpy)	SO_2 (tpy)	PM (tpy)	PM_{10} (tpy)	$PM_{2.5}$ (tpy)	H_2SO_4 (tpy)	VOC (tpy)	GHG as CO_2e (tpy)
Project increase	2,430.82	326.10	40.68	175.78	175.26	173.19	63.86	1,002.83	4,074,700
Net contemporaneous change	2,422.93	-77.96	39.12	156.63	156.11	154.04	65.86	988.97	3,762,138
PSD Major modification threshold	100	40	40	25	15	10	7	40	75,000

Title V Applicability - 30 TAC Chapter 122 Rules

Requirement
Title V applicability: The existing Title V permit No. O69 exists for the Sabine Plant. The permit holder plans to submit a Title V application at a later date for the Orange County Advanced Power Station.

Requirement

Periodic Monitoring (PM) applicability:
The site is a major source for Title V and is subject to the 30 TAC 122 periodic monitoring requirements. The following provisions for monitoring related to this amendment project are included in the special conditions:

- Quarterly visible emissions observations
- Cooling tower water TDS monitoring and sampling
- Recordkeeping of the hours of operation for the emergency generators
- 28PI for fugitive components in contact with natural gas and diesel
- 28AVO for fugitive components in contact with ammonia
- Stack testing for CO, NOx, VOC, NH3, SO2, opacity, and O2 for the gas turbines
- Recordkeeping of the hourly natural gas consumption of each CTG.
- CEMS for NOx, CO and O_2 from each gas turbine
- NH_3 slip testing
- Records of startups, shutdown, and other planned maintenance activities dates and durations.

Compliance Assurance Monitoring (CAM) applicability:
CAM is applicable to the gas turbines at this site for NOx and CO because each turbine has the pre-control potential-to-emit above the major source thresholds for NOx and CO, and a control device is used to achieve compliance with the emission limitations. NOx emissions are controlled by the SCR, while CO emissions are controlled by the oxidation catalyst. CAM is addressed through use of a NO_x and CO CEMS to demonstrate continuous compliance with those pollutants.

Project Scope

ETI proposes construction of a natural gas-fired combined-cycle turbine power plant (OCPS) adjacent to the existing ETI Sabine Plant in Orange County, Texas. OCPS will be a primarily pipeline natural gas-fired, utility scale combined cycle power generation facility, with an option for up to 30 percent volume hydrogen co-firing. The OCPS will be within the property boundary of the existing Sabine Plant.

The Orange County Advanced Power Station (OCPS) will have a predicted net nominal output of 1,215 megawatts (MW) at International Standards Organization (ISO) conditions (59 °F, 1 bar, and 60% relative humidity). Each turbine has an average heat input of 3,756.2 MMBtu/hr and each has a rated nominal capacity of 428 gross MW) at ISO conditions. Each CTG will have a heat recovery steam generator (HRSG) with no supplemental duct firing. Each HRSG supplies steam to a single common steam turbine which drives a third electric generator with a rated nominal capacity of 387 gross MW at ISO Conditions. The plant will not be a co-generation site.

Process Description

The power generation system consists of two natural gas-fired Mitsubishi M501JAC combustion turbines (capable of co-firing up to 30% hydrogen by volume) in a “2 x 1” combined-cycle configuration, meaning the steam produced from the two Heat Recovery System Generators (HRSGs) will supply a single common single steam turbine. The HRSGs for the combined-cycle units will not be equipped with natural gas-fired supplemental firing. ETI is proposing to limit annual operation of the two combustion and HRSG trains under an emissions cap. Separate hourly emissions are requested for the normal and MSS operation of each combustion turbine and HRSG stack.

<u>Normal operation</u>
The turbines will combust natural gas (or a fuel blend that includes up to 30% hydrogen by volume) in dry, lean pre-mix design low NO_x combustors. The alternate scenario where the turbines can co-fire hydrogen up to 30 vol% is driven by business needs.

Two natural gas-fired heaters (FINs OCPSNGWBH and OCPSH2WBH) will be used to generate hot water to initially heat the natural gas and fuel gas blend, respectively. The 16.80-MMBtu natural gas water bath heater with two stacks (EPNs OCPSNGWBHA and OCPSNGWBHB) will heat water to heat the natural gas fuel prior to combustion in the combustion turbines, thereby preventing condensation and achieving the expected delivery temperature upstream of the CTG. Similarly, the 14.00-MMBtu fuel gas water bath heater with two stacks (EPNs OCPSH2WBHA and OCPSH2WBHB) will heat water to heat the hydrogen gas fuel prior to combustion in the combustion turbines, thereby preventing condensation and achieving the expected delivery temperature upstream of the CTG.

The hot exhaust gases from each combustion turbine will be ducted to a waste heat recovery steam generator (boiler) to generate superheated steam, which will then be used to generate additional electricity in a single steam turbine generator. The cooled exhaust gas is vented through the exhaust stack of each CT/HRSG train EPNs OCPS1A and OCPS1B.

An SCR is used to reduce NOx emissions from the HRSG stack. A 29% concentration solution of aqueous ammonia will be vaporized and injected to the exhaust gas stream upstream of a catalyst bed to achieve the NOx reduction. Each HRSG will also include an oxidation catalyst for control of CO and VOC emissions. The combined-cycle system will be capable of generating a total nominal net output of 1,215 MW (nominal output at ISO Conditions). Annual operating hours are based on continuous operation during normal operation.

<u>Startup and Shutdown operation</u>
Startup begins when fuel is introduced and a combustion flame has been established in the CT. Startup ends and normal operation begins when signals are received indicating that the CT is in Environmental Compliance Mode, ammonia injection is in service, and the startup emissions have purged through the continuous emissions monitoring system (CEMS). Normal operations end and planned shutdown begins when signals are received demonstrating that the CT is no longer in Environmental Compliance Mode and that the ammonia injection is no longer in service for purposes of an intended shutdown (i.e., shutdown of the ammonia system was not caused by a system failure). Shutdown ends when a signal is received that the CT has flamed out.

Emissions vary depending on whether the startup is a cold, warm, or hot startup. Cold startups are defined as startups when the unit has been shut down for 64 or more hours prior to startup. Warm startups are defined as startup when the unit has been shut down for between 8 and 64 hours. Hot startups are defined as startups when the unit has been shut down for no more than 8 hours. Startup events may be longer than one hour. Maximum hourly emissions were based on data from the vendor. For flexibility, the startup and shutdown events will be limited by the annual emissions cap for the turbines rather than the number of each startup and shutdown event.

<u>Additional Sources</u>
The combustion turbines and steam turbine will each contain a closed-loop lube oil recirculation system to lubricate moving parts of the turbine and generator. Oil vapor emissions will be generated by oil vaporization, due to heating of lube oil in the turbine and subsequent condensation of droplets when the vapor is cooled. Lube oil mist emissions will be controlled by a mist eliminator and exhausted through dedicated lube oil vents (EPN OCPS-LOV).

OCPS will operate four diesel-fired emergency engines. One 2,922-hp diesel-fired emergency standby generator engine (EPN OCPS-EMGEN) will be used to maintain a reliable backup supply of power to operate critical systems (such as instrumentation, controls, lighting, and HRSG circulator pumps) when grid power is unavailable and to enable safe shutdown of the plant. One 327-hp emergency firewater pump engine (EPN OCPS-FWP) will serve as a backup (emergency) firewater pump for fire protection needs. Two 755-hp emergency fire protection generator engines (EPNs OCPS1AFPGE and OCPS1BFPGE) will be installed for the purpose of maintaining a reliable supply of power to operate the CTG enclosure fire protection system.

A closed-cycle recirculating evaporative cooling tower (EPN OCPS-CTW) will be used to reject heat from the steam turbine condenser. The tower is a mechanical forced draft, multi-cell unit and can operate at a maximum of 13,734,000 gallons of flow per hour.

Piping components in natural gas lines, aqueous ammonia lines for the SCR, and diesel piping have the potential to generate equipment leak fugitive emissions (EPNs OCPS-NGFUG, OCPS-AMMFUG, and OCPS-DSLFUG). Circuit breakers and other SF_6-containing equipment also have the potential to generate equipment leak fugitive emissions (EPN OCPS-CBFUG).

Various maintenance activities (EPN OCPSMSSFUG) will be performed, including on-line turbine water washing, turbine filter change outs, catalyst handling, gaseous fuel venting from the fuel line and small equipment replacement and repair, CEMS analyzer calibration, and small equipment replacement and repair in VOC and ammonia service.

Two 40,000-gallon pressurized storage tanks will store aqueous ammonia at 29% concentration for the SCR system. The tanks are pressurized and will not have routine emissions vented to the atmosphere. The only ammonia emissions associated with these tanks are fugitive component leaks of liquid aqueous ammonia. The tanks are equipped with spill containment, welded piping, and a dedicated truck unloading area including spill containment and storm water management.

The facility will use a variety of ancillary storage tanks, including three control oil tanks including hydraulic fluid, three seal oil tanks, one oil water separator, one bleach tank, one sulfuric acid tank, three natural gas condensate drain tanks, four diesel fuel tanks, and ten lube oil tanks (EPNs OCPSTK1 to OCPSTK26). During the permit review, it was determined that chemicals stored in tanks smaller than 500 gallons in capacity are considered viscous liquids or the storage tanks were categorized as process vessels. This exempted tanks EPNs OCPSTK1 through -TK8, OCPSTK10 through -TK17, and OCPSTK20 through -TK26. OCPSTK7, -TK8, and -TK12 process vessels are oil reservoirs which constantly recirculate oil while the turbines are in operation. OCPSTK17 is an oil water separator. OCPSTK23 and OCPSTK24 are diesel fuel oil tanks to support generator engines. Therefore, recordkeeping requirements are specified only for tanks OCPSTK9 and OCPSTK18-19.

Commissioning Activities

Special Condition (SC) No. 26 states that the performance specifications and concentration limits provided in SC Nos. 5 and 30 and the emission rate limits provided in the MAERT apply beginning with the commencement of operations following completion of construction. The term "completion of construction" as used in SC No. 26 is the same "completion of construction" event that requires a notification to the regional office pursuant to 30 TAC 116.115(b)(2)(A) and General Condition No. 3 of the permit face. The performance specifications, concentration limits, and emission rate limits that are specified in SC Nos. 5 and 30 and the MAERT do not apply to commissioning activities during which initial operational and contractual testing, tuning, boil-out, shakedown, and other activities may occur during this one-time period; these commissioning activities and their associated emissions are not authorized by Permit No. 166032. The one-time commissioning period is limited by SC No. 26 to a maximum of 180 days following the completion of construction date.

Disaster Review

Disaster review is required for storing 29% aqueous ammonia and have fuel blends containing up to 30% hydrogen gas by volume. These quantities of aqueous ammonia and hydrogen gas are above the respective RMP threshold quantities. OCPS will prepare a RMP in accordance with 40 CFR Part 68 and will review and make updates to the plan as per 40 CFR §68.190.

Best Available Control Technology

Source Name	EPN	Best Available Control Technology Description
OCPS Combined Cycle Unit 1A Turbine, Unit 1B Turbine, and the Unit 1 annual emissions cap	OCPS1A, OCPS1B, and OCPS1-CAP	Hourly emissions are based on a maximum heat input of the turbine and a site variability factor, which occurs under maximum load and an ambient temperature of 100°F. Annual emissions are based on average heat input of the turbine, taken at full load, and a design ambient temperature of 69.4°F. The gross heat rate at baseload is 6,059 Btu/kW-hr or 6,762 Btu/kW-hr (with a 9% degradation). **NO_X:** 2.0 ppmvd @ 15% O_2 on a rolling 24-hr average for firing either 100% natural gas or co-firing up to 30 vol% hydrogen with natural gas. The turbines and HRSGs are equipped with Dry Low NOx burners (DLNB) and SCR as post-combustion control. **CO:** 2.0 ppmvd @ 15% O_2 on a rolling 24-hr average for firing either 100% natural gas or co-firing up to 30 vol% hydrogen with natural gas. The turbines and HRSGs are equipped with an oxidation catalyst is used for post-combustion control. **VOC:** 2.0 ppmvd @ 15% O_2 on a 3-hr average for firing either 100% natural gas

Source Name	EPN	Best Available Control Technology Description
		or co-firing up to 30 vol% hydrogen with natural gas, achieved through use of an oxidation catalyst as post-combustion control and use of good combustion practices. **Sulfur compounds:** The sulfur content of natural gas is 0.44 grains sulfur per 100 dscf on an annual basis, while the blended fuel will have a sulfur content of 0.33 grains per 100 dscf, provided by the turbine manufacturer. **$PM/PM_{10}/PM_{2.5}$:** 0.005 lb/MMBtu based on vendor emission estimates for the turbines and an assumed conversion rate of ammonia into ammonium sulfate in the SCR based on vendor data, representing the sum of filterable and condensable particulate. All particulate matter is equal to PM_{10} and $PM_{2.5}$. Good combustion practices will be employed. No active PM control device is technically feasible or has been demonstrated in practice. **NH_3:** 7.0 ppmvd @ 15% O_2 for firing either 100% natural gas or co-firing up to 30 vol% hydrogen with natural gas. Emissions of NH_3 originate from NH_3 slip from the SCR system. Good management practices and operation of the SCR are used. **GHG as CO_2e:** Exclusive use of natural gas and a blend of 30 vol% hydrogen with natural gas as fuels, using a high efficiency combined cycle power generation method, and minimizing fugitive methane and SF_6 releases from associated equipment. The clean thermal efficiency of the combustion turbines is 747.7 lb CO_2/MWh (gross) at full load with the HRSG in operation, including periods of startup and shutdown. A 2% adjustment is applied for performance variability, a 3% adjustment is applied for unrecoverable degradation, and a 4% adjustment is applied for recoverable performance degradation. This results in a total of 9% adjustment, yielding a BACT value of 814.7 lb CO_2/MWh (gross) thermal efficiency. **MSS:** Although the DLNB, SCR system, and oxidation catalyst will still be used to reduce some emissions, NOx, CO, and VOC emissions will be at higher levels than during normal operations. Ammonia injection is initiated during startup after the SCR attains the minimum operating temperature. The duration of startups and shutdowns will be minimized, pollution control equipment will be engaged as soon as possible, and the emissions will be limited to meet the MAERT. Units will start on 100% natural gas only.
OCPS Cooling Tower	OCPS-CTW	The cooling tower will be non-contact design, and the water inlet flow rate is based on the maximum expected flow rate of 13,734,000 gallons per hour. It is not expected to have any hydrocarbon-carrying streams that could contact the cooling water being sent to the towers. Therefore, no quantifiable VOC emissions are expected from this source. The cooling tower cells will employ drift eliminators achieving a drift rate of less than or equal to 0.0005%.
OCPS Fuel Gas Natural Gas Water Bath Heater	OCPSNGWBHA (Stack A) and OCPSNGWBHB (Stack B)	The 16.80 MMBtu/hr natural gas-fired fuel gas water bath heater is used to heat water to warm the natural gas fuel prior to combustion in the combustion turbines. It is authorized for continuous use. Use of pipeline quality natural gas and good combustion practices are employed. **CO:** 50 ppmvd at 3% O_2 (0.0375 lb CO/MMBtu). **NO_x:** 0.04 lb/MMBtu, achieved by use of low-NOx burners. This concentration is accepted as BACT for small natural gas-fired heaters below 40 MMBtu/hr. **VOC:** 5.5 lb/MMscf VOC (0.005 lb VOC/MMBtu). **SO_2:** 0.44 grains sulfur/100 dscf of fuel. SO_2 is based on 100% conversion of sulfur to SO_2.

Source Name	EPN	Best Available Control Technology Description
		$PM/PM_{10}/PM_{2.5}$: 7.6 lb/MMscf (0.007 lb/MMBtu). The maximum opacity is 5%. **CO_2e:** A limit of 8,616.6 tpy CO_2e is proposed for a small heater (less than 100 MMBtu/hr).
OCPS Fuel Gas Hydrogen Gas Water Bath Heater	OCPSH2WBHA (Stack A) and OCPSH2WBHB (Stack B)	The 14.00 MMBtu/hr natural gas-fired fuel gas water bath heater is used to heat water to warm the hydrogen gas fuel prior to combustion in the combustion turbines. It is authorized for continuous use. Use of pipeline quality natural gas and good combustion practices are employed. **CO:** 50 ppmvd at 3% O_2 (0.0375 lb CO/MMBtu). **NO_x:** 0.04 lb/MMBtu, achieved by use of low-NOx burners. This concentration is accepted as BACT for small natural gas-fired heaters below 40 MMBtu/hr. **VOC:** 5.5 lb/MMscf VOC (0.005 lb VOC/MMBtu). **SO_2:** 0.44 grains sulfur/100 dscf of fuel. SO_2 is based on 100% conversion of sulfur to SO_2. **$PM/PM_{10}/PM_{2.5}$:** 7.6 lb/MMscf (0.007 lb/MMBtu). The maximum opacity is 5%. **CO_2e:** A limit of 7,180.5 tpy CO_2e is proposed for a small heater (less than 100 MMBtu/hr).
Emergency generator	OCPS-EMGEN	The 2,922 horsepower (hp) diesel-fired emergency standby generator engine will fire ultra-low sulfur diesel fuel with less than 15 ppmw sulfur. The engine will operate no more than 100 hours per year for non-emergency operating time (routine testing, maintenance, and inspection purposes). Use of good combustion, maintenance practices, and low GHG fuels will be used. The engine meets an emission limit of 1.7 lb CO_2e/kW-hr.
Firewater pump	OCPS-FWP	The 327 hp diesel-fired emergency firewater pump engine will fire ultra-low sulfur diesel fuel with less than 15 ppmw sulfur. The engine will operate no more than 100 hours per year for non-emergency operating time (routine testing, maintenance, and inspection purposes). Use of good combustion, maintenance practices, and low GHG fuels will be used. The engine meets an emission limit of 1.7 lb CO_2e/kW-hr.
Fire protection generators	OCPS1AFPGE and OCPS1BFPGE	The two diesel-fired emergency fire protection generator engines are each rated at 755 hp and will fire ultra-low sulfur diesel fuel with less than 15 ppmw sulfur. Each engine will operate no more than 100 hours per year for non-emergency operating time (routine testing, maintenance, and inspection purposes). Use of good combustion, maintenance practices, and low GHG fuels will be used. The engine meets an emission limit of 1.7 lb CO_2e/kW-hr.
Natural gas fugitives	OCPS-NGFUG	For natural gas piping, natural gas leakage is estimated using SOCMI factors for sources without ethylene. The uncontrolled VOC emissions from fugitive sources are less than 10 tpy. However, ETI implements a 28AVO monitoring program to reduce fugitive emissions from the natural gas piping system. AVO checks are made daily.
Ammonia fugitives	OCPS-AMMFUG	For the SCR system, the ammonia leakage is estimated using SOCMI factors for sources without ethylene. ETI implements a 28AVO fugitive inspection program to reduce fugitive emissions from the SCR system. AVO checks are made daily.
Diesel fugitives	OCPS-DSLFUG	For diesel piping, the diesel leakage was estimated using SOCMI factors for sources without ethylene. Diesel is 100% VOC and the HAP composition is based on a conservative assumption of 2% weight. The uncontrolled site-wide VOC emissions from fugitive sources are less than 10 tpy. No LDAR monitoring is required.

Source Name	EPN	Best Available Control Technology Description
OCPS Lube Oil Vents	OCPS-LOV	The closed-loop lube oil recirculation system will generate oil mist emissions from oil vaporization and condensation, which will be controlled by a mist eliminator on each system and exhausted through dedicated lube oil vents.
OCPS Maintenance Activities	OCPSMSSFUG	Maintenance activities, aside from turbine startup and shutdown, include: 1. On-line turbine water washing 2. Turbine inlet air filter changeouts 3. Catalyst Handling 4. Gaseous Fuel Venting from the fuel line and small equipment 5. CEMS analyzer calibration for NOx and CO 6. Small equipment maintenance, replacement, and repair in VOC and ammonia service. ETI will maintain good air pollution control practices and safe operating practices. ETI will verify all maintenance activities on an annual basis and evaluate emissions each calendar month. A list of the authorized maintenance activities are included as Attachments A and B of this permit.
Storage Tanks	OCPSTK9, OCPSTK11, OCPSTK18, OCPSTK19, OCPSTK23, and OCPSTK24	These fixed roof storage tanks store diesel, bleach, and sulfuric acid. Only tank OCPSTK18 is a vertical fixed roof tank. All other tanks are horizontal fixed roof tanks. These tanks are equipped with bottom fill or submerged fill, have exterior surfaces painted white, unpainted stainless steel, or unpainted aluminum. Only tank OCPSTK18 is a polyethylene tank for corrosivity purposes. All tanks store chemicals with below 0.5 psia true vapor pressure or the tank is less than 25,000 gallons in size. Therefore, vapors from storage of chemicals are routed to the atmosphere.
Process vessels	OCPSTK1-8, OCPSTK10, OCPSTK12-17, OCPSTK20-22, OCPSTK25, and OCPSTK26	These process vessels were originally considered fixed roof storage tanks by the applicant. It was determined that chemicals stored in tanks smaller than 500 gallons in capacity are considered viscous liquids or the storage tanks were categorized as process vessels. These vessels store and process organic and inorganic liquids with low vapor pressures and generally low annual throughputs (hydraulic fluid, seal oil, bleach, sulfuric acid, natural gas condensate, and lube oil).
OCPS Circuit Breaker Fugitives	OCPS-CBFUG	Fugitive SF_6 emissions occur from circuit breaker leakage. SF_6 is used in high voltage electrical equipment as an insulator and/or arc quenching medium. Up to 10 circuit breakers will be used. A plant-wide emission limit of 76 tpy of CO_2e on a rolling 12-month average is proposed. State-of-the-art circuit breakers that are gas-tight and require minimal SF_6 are used. An AVO monitoring program is used to detect circuit breaker leaks. Use of good operations and preventative maintenance practices are employed.

Impacts Evaluation

Was modeling conducted?	**Yes**	Type of Modeling:	**AERMOD**
Is the site within 3,000 feet of any school?			**No**
Additional site/land use information: Medium roughness and elevated terrain were used in the modeling analysis.			

ERM, on behalf of Entergy Texas, Inc, conducted air dispersion modeling, including PSD modeling and a minor NAAQS analysis, which was all audited by the Air Dispersion Modeling Team.

Based on the results of the dispersion model, no short-term or long-term adverse health effects are expected to occur among the public health, welfare, or the environment as a result of exposure to the emissions from the facilities authorized under this permit. The results are summarized below and were deemed acceptable for all review types and pollutants.

Ozone and PM_{10} impacts did not exceed the PSD De Minimis analysis, while the $PM_{2.5}$ and CO impacts passed the full PSD NAAQS standards. PM2.5 also passed the PSD Increment analysis. Minor NAAQS analysis for SO_2 and NO_2 emission rates did not exceed De Minimis levels, except for 1-hour NO_2 which did not exceed the NAAQS standard. Additionally, impacts associated with site-wide SO_2 and H_2SO_4 emissions did not exceed any State Property Line Standard.

All health effects pollutants were evaluated under the TCEQ Modeling and Effects Review Applicability (MERA) guidance document (APDG 5874) and determined acceptable. These pollutants are ammonia; benzene; diesel fuel; formaldehyde; C15-30 petroleum lubricating oils, hydrotreated neutral oil-based; polycyclic aromatic hydrocarbons; sodium hypochlorite; and cadmium. For simplicity purposes, the site-wide modeling of these pollutants were evaluated in and fell out of the Toxicology Effects Evaluation Tier I of the MERA, which states that the GLCmax has to be less than the respective ESL.

More detailed information regarding the air quality analysis can be found in the ADMT modeling memo dated April 21, 2022, Central File Room Content ID 6043315.

Project Reviewer	Date	Team Leader	Date
Huy Pham		Joel Stanford	