TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

EXAMPLE A

NOTICE OF APPLICATION AND PRELIMINARY DECISION
FOR AIR QUALITY PERMIT

PROPOSED AIR QUALITY PERMIT NUMBERS 130051, PSDTX1450, AND GHGPSDTX131

APPLICATION AND PRELIMINARY DECISION. Brazos Electric Power Cooperative, Inc., 7616 Bagby Avenue, Waco, Texas 76712-6924, has applied to the Texas Commission on Environmental Quality (TCEQ) for issuance of proposed air quality permits State Permit Number 130051, Prevention of Significant Deterioration (PSD) Permit Number PSDTX1450, and PSD Greenhouse Gas (GHG) Permit Number GHGPSDTX131. The permits would authorize construction of the Hill County Generation Facility, a new natural gas-fired simple cycle combustion turbine power plant. The project site is at 3750 Farm-to-Market Road 66, Grandview, Hill County, Texas 76050. The proposed facility will emit the following air contaminants in a significant amount: volatile organic compounds, carbon monoxide, nitrogen oxides, particulate matter including particulate matter with diameters of 10 microns or less (PM_{10}) and 2.5 microns or less ($PM_{2.5}$), and greenhouse gases. In addition, the facility will emit the following air contaminants: hazardous air pollutants, sulfur dioxide, and sulfuric acid.

For the 24-hr average $PM_{2.5}$ national ambient air quality standard, the degree of PSD increment predicted to be consumed by the proposed facility and other increment-consuming sources in the area is 2.24 $\mu g/m^3$, below the 9 $\mu g/m^3$ allowed consumption for this standard. For all other PSD increments, the amounts of increment predicted to be consumed by the proposed facility are below de minimis levels.

This application was submitted to the TCEQ on February 9, 2015. The executive director has determined that the emissions of air contaminants from the proposed facility which are subject to PSD review will not violate any state or federal air quality regulations and will not have any significant adverse impact on soils, vegetation, or visibility. All air contaminants have been evaluated, and “best available control technology” will be used for the control of these contaminants.

The executive director has completed a technical review of the application and prepared a draft permit which, if approved, would establish the conditions under which the facility must operate. The permit application, executive director’s preliminary decision, preliminary determination summary, air quality analysis, and draft permit will be available for viewing and copying at the TCEQ central office, the TCEQ Waco regional office, and the Hillsboro City Library, 118 South Waco Street, Hillsboro, Hill County, Texas, beginning the first day of publication of this notice. The facility’s compliance file, if any exists, is available for public review in the Waco Regional Office of the TCEQ, 6801 Sanger Avenue, Suite 2500, Waco, Texas.

INFORMATION AVAILABLE ONLINE. The following documents are accessible through the Commission’s Web site at www.tceq.texas.gov/goto/cid: the executive director’s preliminary decision which includes the draft permit, the executive director’s preliminary determination summary, the air quality analysis, and, once available, the executive director’s response to comments and the final decision on this application. You may access the Commissioners’ Integrated Database (CID) using the above link and entering the permit number for this application. The Hillsboro City Library provides public access to the internet. The following link to an electronic map of the site or facility's general location is provided as a public courtesy and is not part of the application or notice: http://www.tceq.texas.gov/assets/public/hb610/index.html?lat=32.2411&lng=-97.0714&zoom=13&type=r. For the exact site location, refer to the permit application.

PUBLIC COMMENT/PUBLIC MEETING. You may submit public comments or request a public meeting to the Office of the Chief Clerk at the address below. The purpose of a public meeting is to provide the opportunity to submit comment or to ask questions about the application. The TCEQ will hold a public meeting if the executive director determines that there is a significant degree of public interest in the application, if requested by an interested person, or if requested by a local legislator. A public meeting is not a contested case hearing. **You may submit additional written public comments within 30 days of the date of newspaper publication of this notice in the manner set forth in the AGENCY CONTACTS AND INFORMATION paragraph below.**

After the deadline for public comment, the executive director will consider the comments and prepare a response to all public comment. **The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application. The mailing will also provide instructions for requesting a contested case hearing or reconsideration of the executive director's decision.**

OPPORTUNITY FOR A CONTESTED CASE HEARING. You may request a contested case hearing regarding the portions of the application for State Air Quality Permit Number 130051 and for PSD Air Quality Permit Number PSDTX1450. There is no opportunity to request a contested case hearing regarding the portion of the application for GHG PSD Air Quality Permit Number GHGPSDTX131. A contested case hearing is a legal proceeding similar to a civil trial in a state district court. A person who may be affected by emissions of air contaminants from the facility is entitled to request a hearing. A contested case hearing request must include the following: (1) your name (or for a group or association, an official representative), mailing address, daytime phone number; (2) applicant's name and permit number; (3) the statement "I/we request a contested case hearing;" (4) a specific description of how you would be adversely affected by the application and air emissions from the facility in a way not common to the general public; (5) the location and distance of your property relative to the facility; and (6) a description of how you use the property which may be impacted by the facility. If the request is made by a group or association, one or more members who have standing to request a hearing and the interests the group or association seeks to protect must also be identified. You may also submit your proposed adjustments to the application/permit which would satisfy your concerns. Requests for a contested case hearing must be submitted in writing within 30 days following this notice to the Office of the Chief Clerk, at the address provided in the information section below.

A contested case hearing will only be granted based on disputed issues of fact that are relevant and material to the Commission's decisions on the application for State Air Quality Permit Number 130051 and PSD Air Quality Permit Number PSDTX1450. Further, the Commission will only grant a hearing on issues submitted by you or others during the public comment period that have not been withdrawn. Issues that are not submitted in public comments may not be considered during a hearing.

EXECUTIVE DIRECTOR ACTION. The executive director may issue final approval of the application for the portion of the application for GHG PSD Air Quality Permit GHGPSDTX131. If a timely contested case hearing request is not received or if all timely contested case hearing requests are withdrawn regarding State Air Quality Permit Number 130051 and for PSD Air Quality Permit Number PSDTX1450, the executive director may issue final approval of the application. The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application, and will be posted electronically to the CID. If any timely hearing requests are received and not withdrawn, the executive director will not issue final approval of State Air Quality Permit Number

130051 and for PSD Air Quality Permit Number PSDTX1450 and will forward the application for those permits and requests to the Commissioners for their consideration at a scheduled commission meeting.

MAILING LIST. You may ask to be placed on a mailing list to obtain additional information on this application by sending a request to the Office of the Chief Clerk at the address below.

AGENCY CONTACTS AND INFORMATION. Public comments and requests must be submitted either electronically at www.tceq.texas.gov/about/comments.html, or in writing to the Texas Commission on Environmental Quality, Office of the Chief Clerk, MC-105, P.O. Box 13087, Austin, Texas 78711-3087. If you communicate with the TCEQ electronically, please be aware that your email address, like your physical mailing address, will become part of the agency's public record. For more information about this permit application or the permitting process, please call the Public Education Program toll free at 1-800-687-4040. Si desea información en Español, puede llamar al 1-800-687-4040.

Further information may also be obtained from Brazos Electric Power Cooperative Inc., 7616 Bagby Avenue, Waco, Texas 7612-6924 or by calling Mr. Mike Meyers, Manager of Environmental Services, at (254) 750-6228.

Notice Issuance Date: December 18, 2015

Special Conditions

Permit Numbers 130051, PSDTX1450, and GHGPSDTX131

Emission Rates and Permit Representations

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. This permit also authorizes greenhouse gas (GHG) emissions from those emission points listed in the attached MAERT.

2. Emission limits are based upon representations in the permit application dated February 6, 2015, as subsequently updated.

Federal Applicability

3. The sources identified in this condition are subject to and shall comply with applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations in Title 40 Code of Federal Regulations (40 CFR) as follows:

   A. In 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):

<table>
<tr><th>Source</th><th>Emission Point Number (EPN)</th><th>Subpart</th><th>Standards of Performance for:</th></tr>
<tr><td rowspan="2">Combustion Turbines (CTs)</td><td rowspan="2">CT1, CT2, CT3, CT4</td><td>KKKK</td><td>Stationary Gas Turbines</td></tr>
<tr><td>TTTT</td><td>GHG Emissions for Electric Generating Units</td></tr>
<tr><td>Emergency Generator Engines</td><td>EDG1, EDG2</td><td rowspan="2">IIII</td><td rowspan="2">Stationary Compression-Ignition Internal Combustion Engines</td></tr>
<tr><td>Fire Water Pump Engine</td><td>FWP-1</td></tr>
<tr><td colspan="2">All of the above sources</td><td>A</td><td>General Conditions</td></tr>
</table>

   B. In 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants (HAP) for Source Categories:

<table>
<tr><th>Source</th><th>EPN</th><th>Subpart</th><th>Standards for HAP for:</th></tr>
<tr><td>Emergency Generator Engines</td><td>EDG1, EDG2</td><td rowspan="2">ZZZZ[1]</td><td rowspan="2">Stationary Reciprocating Internal Combustion Engines[1]</td></tr>
<tr><td>Fire Water Pump Engine</td><td>FWP-1</td></tr>
<tr><td colspan="2">Both of the above</td><td>A[1]</td><td>General Conditions[1]</td></tr>
</table>

[1]According to 40 CFR § 63.6590(c)(1), compliance with Part 63 is met by compliance with NSPS Subpart IIII.

Operating Limitations, Performance Standards, and Fuel Specifications

4. This permit authorizes four CTs to operate in simple cycle, fueled with either natural gas or ultra-low sulfur diesel (ULSD). Each CT shaft drives an electric generator (CTG). The CTs may employ evaporative cooling for power enhancement. Exhaust emissions are controlled using dry low-NO_x combustors.

   A. (1) The CTs that may be constructed are: General Electric (GE) models GE 7FA.03, GE 7FA.04, GE 7FA.05, or Siemens SGT6-5000F(5)ee.

      (2) Within sixty days after issuing a purchase order for the CTs, the permit holder must notify the Texas Commission on Environmental Quality (TCEQ) of the selected CT model, submitted with a request to revise this permit to delete language applicable to the non-selected CT models.

   B. The CTs are authorized to operate in normal operation, defined as operation that is not MSS operation.

   C. The CTs are authorized for planned MSS operations as follows:

      (1) startup, as defined in Special Condition No. 10.C.;

      (2) shutdown, as defined in Special Condition No. 10.D.; and

      (3) planned maintenance, as described in Attachment A, subject to the conditions of this permit and the representations in the permit application.

   D. Operation of the CTs on ULSD fuel oil is limited to:

      (1) the following heat input in million British thermal units (MMBtu), high heating value (HHV), 12-month rolling time period for each CT;

         (a) GE 7FA.03 – 624,000

         (b) GE 7FA.04 – 644,000

         (c) GE 7FA.05 – 701,000

         (d) SGT6-5000F(5)ee – 693,000; and

      (2) based on air dispersion modeling of nitrogen oxides (NO_x) emissions in the permit application for ULSD fuel firing, the following maximum number of CTs operating simultaneously:

         (a) for the GE 7FA.03 or GE 7FA.05 option, one CT;

         (b) for the GE 7FA.04 option, two CTs; and

         (c) for the SGT6-5000F(5)ee option, three CTs.

5. A. Emissions from EPNs CT1, CT2, CT3, and CT4 while operating in normal operation shall not exceed the following concentrations in parts per million by volume, dry basis (ppmvd) at 15% oxygen (O_2). Compliance with the NO_x and carbon monoxide (CO) concentration limits shall be demonstrated on a three-hour rolling average using the continuous emissions monitoring systems (CEMS) required by Special Condition No. 15.

Pollutant	Fuel	CTs	Concentration
NO_x	Natural Gas (NG)	All models	9.0
	Fuel Oil (FO)	GE models	42
		Siemens	25
CO	NG	GE models	9.0
		Siemens	4
	FO	GE models	20
		Siemens	10

B. Emissions from EPNs CT1, CT2, CT3, and CT4 while operating in MSS operation shall not exceed the MSS emission limits in the attached MAERT.

6. A. Annual emissions from each CT are limited by the following restrictions:

CT Activity	Annual Limit[1]
Startup & Shutdown hours	400
Operating hours[2]	2,920

[1]Annual is a 12-month rolling average.
[2]Including normal and MSS operations.

B. The number of hours of CT operation in startup, shutdown, and normal operating modes may be demonstrated with operating time records of parameters such as fuel feed rates or power generation. Only the portion of the hours that CT1, CT2, CT3, and CT4 are in startup or shutdown mode, as defined in Special Condition Nos. 10.C. and 10.D., will be used to demonstrate compliance with the limits for startup and shutdown hours in Special Condition No. 6.A.

7. A. During normal operation, opacity of emissions from the EPNs CT1, CT2, CT3, and CT4 exhaust stacks shall not exceed 5% averaged over a six-minute period. During planned MSS activities, the opacity shall not exceed 15%. Each determination shall be made by first observing for visible emissions

while the facility is operating. Visible emission observations shall be made at least 15 feet and no more than 0.25 mile from the emission point. If visible emissions are observed from an emission point, opacity shall be determined in accordance with 40 CFR Part 60, Appendix A, Test Method 9. The opacity test must be performed by a certified opacity reader. Contributions from uncombined water shall not be included in determining compliance with this condition.

B. Visible emission observations shall be performed and recorded once per quarter if the CT is in operation during daylight hours during the calendar quarter. If the opacity exceeds 5% during normal operation or 15% during MSS activities, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation.

8. The 1 megawatt (MW) emergency generator engines (EPNs EDG-1 and EDG-2) and the 260 horsepower emergency fire water pump engine are each limited to 100 hours of non-emergency operation per year, on a rolling 12-month basis. Each engine shall be equipped with a non-resettable elapsed run time meter.

9. Fuel Specifications

A. The CT fuels shall be limited to:

(1) pipeline-quality, sweet natural gas containing no more than 5 grains total sulfur per 100 dry standard cubic feet (dscf); and

(2) ULSD fuel oil containing no more than 15 ppm by weight (ppmw) sulfur.

B. The emergency diesel engines shall be limited to ULSD fuel oil containing no more than 15 ppmw sulfur by weight.

C. Upon request by the Executive Director of the TCEQ or any air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel fired in the CTs or engines, or shall allow air pollution control agency representatives to obtain a sample for analysis.

Routine Maintenance, Startup and Shutdown

10. The emissions from planned MSS activities related to CT1, CT2, CT3, and CT4 will be minimized by the following:

A. Facility and air pollution control equipment will be operated in a manner consistent with good practices for minimizing emissions.

B. The duration of operation in MSS mode will be minimized and the applicable emissions monitoring systems will be kept in operation.

C. Startup.

(1) A single startup event for each CT shall not exceed 30 minutes on natural gas and 40 minutes on fuel oil except for those startup events that are also planned maintenance activities under 10.E.(2) of this Special Condition.

(2) A startup event is defined as the period that begins when fuel flow is initiated in the CT as indicated by flame detection and ends when the normal operating low-NO_x combustion mode is achieved.

D. Shutdown.

(1) A single shutdown event for each CT shall not exceed 30 minutes for natural gas and 40 minutes for fuel oil.

(2) A shutdown event is defined as the time period that begins when the CT drops out of the normal operating low-NO_x combustion mode following an instruction to shut down, and ends when flame is no longer detected in the CT combustors. A shutdown event will also end if the CT is instructed to return to normal operating low-NO_x combustion operating mode and subsequently achieves normal operating low-NO_x combustion mode.

E. Maintenance.

(1) Maintenance activities authorized in this permit for the CTs are identified as any of the following:

(a) CEMs maintenance and calibration.

(b) Dry low NO_x burner tuning sessions. Tuning sessions are scheduled events and would occur after the completion of initial construction, a combustor change-out, a major repair, maintenance to a combustor, or other similar circumstances.

(c) Rotor maintenance, including rotor burn-in.

(2) Combustion tuning/optimization and rotor burn-in of the CT is limited to 20 hours per event.

F. The MSS activities identified in 10.C., D., and E. of this Special Condition are authorized provided that the mass emission rates in pounds per hour (lbs/hr) do not exceed those specified in the MAERT.

11. Emissions from the planned maintenance activities identified in Attachment A other than the CTs are authorized subject to the emission limits specified in the MAERT.

Initial Determination of Compliance

12. Sampling ports and platforms shall be incorporated into the design of all exhaust stacks according to the specifications set forth in the attachment entitled "Chapter 2, Stack Sampling Facilities." Alternate sampling facility designs may be submitted for approval by the TCEQ Waco Regional Director. The exhaust stacks for CTs CT1, CT2, CT3, and CT4 will be built approximately to the following dimensions:

CT Model	Diameter (feet)	Height (feet)
GE 7FA.03	24	100
GE 7FA.04	24	100
GE 7FA.05	26	100
SGT6-5000F(5)ee	26	100

13. The holder of this permit shall perform stack sampling and other testing to establish the actual quantities of air contaminants being emitted into the atmosphere from EPNs CT1, CT2, CT3, and CT4. Unless otherwise specified in this Special Condition, the sampling and testing shall be conducted in accordance with the methods and procedures specified in Special Condition No. 14. The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

    A. Air contaminants and diluents from the CTs to be sampled and analyzed include (but are not limited to) NO_x, CO, volatile organic compounds (VOC), sulfur dioxide (SO_2), opacity, O_2, and particulate matter (PM).

    B. The turbines shall be tested at the maximum load for the atmospheric conditions which exist during testing. Turbine generator load shall be identified in the sampling report.

    C. Fuel sampling using the methods and procedures of 40 CFR § 60.4415 may be conducted in lieu of stack sampling for SO_2. If fuel sampling is used, compliance with 40 CFR Part 60, Subpart KKKK SO_2 limits shall be based on 100% conversion of the sulfur in the fuel to SO_2.

D. Requests to waive testing for any air contaminant specified in this condition shall be submitted to the TCEQ Air Permits Division. Test waivers and alternate or equivalent procedure proposals for NSPS testing which must have EPA approval shall be submitted to the TCEQ Air Permits Division.

E. Sampling as required by this condition shall occur within 60 days after achieving the maximum production but no later than 180 days after initial startup of each unit. Additional sampling shall occur as may be required by the TCEQ or EPA.

14. A. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ "Sampling Procedures Manual" and EPA Test Methods in 40 CFR Part 60, Appendix A.

B. The TCEQ Waco Regional Office shall be given notice as soon as testing is scheduled but not less than 30 days prior to sampling to schedule a pretest meeting.

(1) The notice shall include:

(a) Date for pretest meeting.

(b) Date sampling will occur.

(c) Name of firm conducting sampling.

(d) Type of sampling equipment to be used.

(e) Methods and procedures to be used in sampling, including methods to demonstrate compliance with emission standards found in 40 CFR Part 60, Subpart KKKK.

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

(2) The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports.

(3) Prior to the pretest meeting, a written proposed description of any deviation from sampling procedures specified in permit conditions or TCEQ or EPA sampling procedures shall be made available to the TCEQ.

The TCEQ Regional Director shall approve or disapprove of any deviation from specified sampling procedures.

C. Copies of the final sampling report shall be forwarded to the TCEQ and EPA within 60 days after sampling is completed. Sampling report format shall comply with Chapter 14 of the TCEQ "Sampling Procedures Manual". Three copies of the reports, including at least one electronic copy, shall be sent to the TCEQ Regional Office in Waco.

Continuous Determination of Compliance

15. The permit holder shall install, calibrate, and maintain a CEMS to measure and record the in-stack concentration of NO_x, CO, and O_2 from each CT stack, EPNs CT1, CT2, CT3, and CT4.

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. 2 and 3, 40 CFR Part 60, Appendix B. The permit holder shall assure that the CEMS meets the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, 5.2.3 and any CEMS downtime shall be reported to the TCEQ Waco Regional Director, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the TCEQ Waco Regional Director. Compliance with the CEMS requirements of 40 CFR Part 60 can be demonstrated by meeting the applicable requirements of 40 CFR Part 75 provided that the holder of this permit demonstrates compliance with all applicable 40 CFR Part 60 emission standards.

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 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 60, Appendix F), CGA exceedances of ±15% accuracy, and any CEMS downtime shall be reported to the TCEQ Waco Regional Director, and necessary corrective action shall be taken. This information may be reported semiannually to the Waco Regional Office with applicable NSPS or Title V deviation reporting. Supplemental stack sampling may be required at the discretion of the TCEQ Waco Regional Director.

D. If any emission monitor fails to meet specified performance, it shall be repaired or replaced immediately. If repair or replacement is not immediately feasible, the monitor shall be repaired or replaced no later than seven days after the failure is first detected by an employee at the site, unless written permission is obtained from the TCEQ which allows for longer repair/replacement time. The holder of this permit shall develop an operation and maintenance program (including stocking necessary spare parts) to ensure that the continuous monitors are available as required. A monitor with downtime due to breakdown or repair of more than 10% of the facility operating time for any calendar year will be considered as a defective monitor and the monitor must be replaced within two weeks after exceeding the 10% threshold.

E. For full operating hours, the monitoring data must be reduced to hourly average values at least once every day, using a minimum of four approximately equally-spaced data points from each one-hour period. For hours in which monitoring system quality assurance, maintenance, breakdowns, or repairs occur, at least two valid data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour) will be sufficient for the hour to be considered a valid hour.

F. The valid hourly average data from the CEMS will be used to determine compliance with the concentration limits of Special Condition No. 5.A. and, in conjunction with the program required by Special Condition No. 16, the hourly emission rate limits in the MAERT. Only quality assured data from the CEMS shall be used to identify excess emissions, except that during periods where the CEMS data is unavailable or not quality assured, compliance may alternatively be determined by using manufacturer emission factors or valid and representative data previously measured and recorded by the unit's CEMS under similar operating conditions. Periods where the missing data substitution procedures in Subpart D of 40 CFR Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required in 40 CFR § 60.7(c).

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

16. The holder of this permit shall either measure, or develop a program to calculate, the total mass flow rate through the stacks to ensure continuous compliance with the emission limitations specified in the MAERT. The permit holder shall calculate hourly mass emissions in lbs/hr using the measured or calculated exhaust flow rate and the measured concentrations of NO_x and CO from the CEMS required in Special Condition No. 15. The hourly calculated values will be cumulatively added during each hour of the month and stored on a computer hard drive or other TCEQ-accepted computer media. Records of this information shall also be available in a form suitable for inspection.

17. The permit holder shall monitor fuel consumption from CT1, CT2, CT3, and CT4 individually and continuously, using fuel flow monitoring devices that are accurate to ±2.0% of the unit's maximum flow. The devices shall be maintained and operated in accordance with the manufacturer's specifications and calibrated in accordance with the manufacturer's recommendations or at least annually. The fuel flow meters must meet the applicable requirements, including specifications and certification testing, of 40 CFR Part 75, Appendix D and 40 CFR Part 60. The fuel flow meter data shall be automatically recorded with a data acquisition and handling system.

18. After the initial demonstration of compliance, ongoing compliance with the VOC and PM tons per year emission rates in the MAERT shall be demonstrated by calculating rolling 12-month annual emissions from emission factors (lb/MMBtu, HHV) obtained from the results of the sampling required by Special Condition No. 13 and the monthly total heat input (MMBtu, HHV) from natural gas fuel.

Recordkeeping Requirements

19. 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 TCEQ, EPA, or any air pollution control agency with jurisdiction.

A. A copy of this permit.

B. Permit application dated February 6, 2015 and supplemental information provided June 16, 2015, and November 3, 2015.

C. A complete copy of the testing reports and records of the initial performance testing completed pursuant to Special Condition No. 13 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.

20. The following information shall be maintained at the plant site 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 air pollution control agency with jurisdiction.

A. For the combustion turbines, records of the following:

(1) The CEMS data of NO_x, CO, and O_2 emissions from the CTs to demonstrate compliance with the performance standards in Special Condition No. 5.A., the startup and shutdown duration limits in Special Condition No. 10, and the emission rates listed in the MAERT. Records must be kept for all hourly, three-hour rolling, monthly, and 12-month rolling periods corresponding to emission limits. Data retention at intervals less than one hour is not required for normal operation. Periods of MSS should be identified to the nearest minute.

(2) Raw data files of all CEMS data including calibration checks and adjustments and maintenance performed on these systems.

(3) Fuel purchases, copies of gas supply contracts, test results, or other information to show compliance with the sulfur limits of Special Condition Nos. 3.A. and 9.A.

(4) The amount of natural gas and fuel oil fired on an hourly, monthly, and rolling 12-month basis in each of the CTs to show compliance with Special Condition No. 4.D. and the MAERT.

(5) The hours of operation of each CT to show compliance with Special Condition No. 6.

(6) Calibrations, preventative maintenance, and/or repairs performed on fuel flow meters.

B. Records of visible emission observations and if required, opacity readings, as specified in Special Condition No. 7.

C. For the emergency diesel engines, hours of operation in emergency and non-emergency operation, on a monthly and 12-month rolling basis to demonstrate compliance with Special Condition No. 8; and sulfur content pursuant to Special Condition No. 9.B.

Reporting

21. The holder of this permit shall submit to the TCEQ Waco Regional Office and the Air Enforcement Branch of the EPA in Dallas semiannual reports as described in 40 CFR § 60.7. Such reports are required for each emission unit which is required to be continuously monitored pursuant to this permit.

Performance Standards for GHG Emissions

22. A. While operating at normal operational loads, the CTs (EPNs: CT1, CT2, CT3 and CT4) shall not exceed the following output-based carbon dioxide (CO_2) emission limits on a 12-month rolling average:

Turbine Model	Output-Based CO_2 Emission Limit (lbs CO_2/MWh)
GE7FA.03	1,434
GE7FA.04	1,415
GE7FA.05	1,388
SGT6-5000F(5)ee	1,406

B. While operating in startup and shutdown modes, the CTs shall not exceed the following CO_2 emission rates on a rolling 12-month basis:

Turbine Model	CO_2 Emission Limit (tons CO_2/h)	
	Natural gas	Fuel oil
GE7FA.03	55	109
GE7FA.04	58	113
GE7FA.05	64	123
SGT6-5000F(5)ee	68	121

Initial Demonstration of Compliance for GHG Emissions

23. After the first 250 hours or 30 operating days of commercial operation, whichever comes first, the permit holder shall compare that month's output-specific CO_2 emission rate to the applicable limit in Special Condition No. 22.A. Within 45 days thereafter, the permit holder shall submit a report to the Waco Regional Office of

the TCEQ identifying whether the data causes any concerns regarding the permit holder's ability to comply with Special Condition. No. 22.A. or the MAERT, and any actions that have been taken or are planned to be taken to address those concerns.

Continuous Compliance for GHG Emissions

24. The permit holder shall install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the natural gas and fuel oil consumption in the CTs and the gross electric output of the CT generators. The monitoring system data shall be used to demonstrate continuous compliance with the performance specifications of Special Condition No. 22 and the emission limits of the attached MAERT. The data must be converted into units of the applicable standards as follows.

    A. Calculate for each CT the hourly:

        (1) Heat input.

            (a) Natural gas fuel. Calculate the hourly heat input in million Btus, using the measured fuel flow and the HHV of the natural gas fuel. Calculate the heat input consistent with Equation F-20 and the procedures for determining the HHV, in Section 5.5.2 of 40 CFR Part 75, Appendix F. In this section, the HHV is referred to as the gross calorific value of gaseous fuel (GCV_g) and is expressed in Btu/100 scf. The fuel supply must be sampled and analyzed for HHV at least monthly. The HHV may also be verified by the fuel supplier at least once every month to satisfy the HHV sampling requirement.

            (b) ULSD fuel oil. Calculate the hourly heat input in million Btus, using the measured fuel flow and the HHV (GCV_o) of the fuel oil. Calculate the heat input consistent with Equation F-19 and the procedures for determining the HHV, in Section 5.5.1 of 40 CFR Part 75, Appendix F.

        (2) CO_2 emission rate.

            (a) Natural gas fuel. Calculate the hourly CO_2 emission rate in short tons per hour, during all periods of natural firing operation, in accordance with 40 CFR Part 75, Appendix G, section 2.3, Equation G-4, using:

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

                (ii) a custom emission factor determined in accordance with 40

CFR Part 75, Appendix F, section 3.3.6, Equation 7-b.

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

(i) the default emission factor of 162.3 lb CO_2/MMBtu; or

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

(3) Gross electric output. Calculate the gross electric output of each CT in MWh on an hourly basis.

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

(5) Methane (CH_4) and nitrous oxide (N_2O) emissions. Calculate the CH_4 and N_2O emission rates in short tons per hour during all periods of operation, using the:

(a) measured hourly heat input;

(b) default emission factors from Table C-2 of 40 CFR Part 98, Subpart C for

(i) natural gas fuel, $1.0(10^{-3})$ kg CH_4/MMBtu and $1.0(10^{-4})$ kg N_2O/MMBtu; and

(ii) fuel oil, $3.0(10^{-3})$ kg CH_4/MMBtu and $6.0(10^{-4})$ kg N_2O/MMBtu; and

(c) conversion factors of 0.45359 kg/lb and 2,000 lb/ton.

(6) Emission rate of carbon dioxide equivalent (CO_2e). Calculate the CO_2e emission rate, in short tons per hour, as the sum of the CO_2 emissions and the CO_2e-converted emissions of CH_4 and N_2O. The CH_4 and N_2O emission rates are converted to CO_2e emissions using the Global Warming Potentials of 25 for CH_4 and 298 for N_2O, from Table A-1 of 40 CFR Part 98, Subpart A, version effective January 1, 2015.

B. Hourly to 12-month rolling data. Calculate for each CT, the 12-month rolling average:

(1) Output-specific CO_2 emissions, to show compliance with the limits of Special Condition No. 22.A. Monthly output-specific CO_2 emissions are

the sum of the hourly CO_2 emissions for the month, excluding periods of MSS, divided by the sum of the hourly gross output for the same hourly periods. At the end of each calendar month, add the monthly CO_2 emissions to the monthly CO_2 emissions for the preceding 11 operating months and divide the resulting sum by the gross output in MWh for the same period. An operating month is any calendar month in which the CT operated in normal operation for any time.

(2) Emissions of CO_2, CH_4, N_2O, and CO_2e in tons per year to show compliance with the limits of the MAERT. Monthly emissions are the sum of the hourly emissions for that month and include all periods of operation. At the end of each calendar month, add the monthly emissions to the monthly emissions for the previous 11 calendar months.

25. Alternative monitoring of CO_2. The permit holder may, as an alternative to monitoring CO_2 emissions in accordance with Special Condition No. 24, install and operate a CO_2 CEMS, a volumetric stack gas flow monitor, and an automated data acquisition and handling system in accordance with the CO_2 CEMS system requirements in 40 CFR § 75.10(a)(3) and (a)(5) for measuring and recording the CO_2 emissions to the atmosphere from EPNs CT1, CT2, CT3, or CT4.

26. The sulfur hexafluoride (SF_6) enclosed circuit breakers used to prevent damage in the event of a power surge must be designed to meet the latest American National Standards Institute C37.013 standard for high-voltage circuit breakers. The circuit breakers must be guaranteed to achieve a SF_6 leak rate of 0.5% by weight or less annually. The circuit breakers must be in a totally enclosed, pressurized compartment equipped with an alarm that signals the plant control room in the event that any circuit breaker loses pressure to the extent that 10% of the SF_6 has leaked. The permit holder shall equip the circuit breakers with a low pressure lockout. As soon as practicable following the detection of a leak, plant personnel shall take one or more of the following actions:

A. Locate and isolate the leak using an SF_6 leak collection or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

B. Commence repair or replacement of the leaking component.

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

A. Piping and valves in natural gas service within the operating area must be checked weekly for leaks using audio, visual, and olfactory (AVO) sensing for natural gas leaks. If the site is not manned for a given week, an AVO check shall be performed the next week plant personnel are on-site.

B. 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) Close valves to stop leak if immediate repair is not possible.

28. The permit holder shall minimize the duration of uncontrolled venting of natural gas during MSS according to good engineering practices.

Additional Recordkeeping for GHG Emissions

29. The following information shall be maintained at the plant site 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 air pollution control agency with jurisdiction.

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

B. For the combustion turbines, records of the following:

(1) Purchase records of all fuels fired.

(2) Monthly samples of natural gas HHV, from the permit holder or the fuel supplier;

(3) Fuel usage in MMBtu, electric generation in MWh, CH_4, N_2O, CO_2, and CO_2e emissions, and output-specific CO_2 emissions in lb CO_2/MWh, on hourly, monthly, and 12-month rolling average bases.

(a) Data retention at intervals less than one hour is not required for normal operation. Periods of MSS should be identified to the nearest minute.

(b) Records of emission rates should identify the times when emissions data have been excluded from the calculation because of monitoring system malfunction.

(c) Records of output-specific CO_2 emissions should identify the times when emissions have been excluded from the calculation because of MSS operation or monitoring system malfunction.

(d) The records should identify numerical factors used in calculations that are used to demonstrate compliance with emission limits and the performance standard.

(4) Hours of operation, identifying startup and shutdown periods.

C. For the SF_6 containing circuit breakers, dates and times of triggered alarms and maintenance or leak repair performed.

D. For the fuel piping, valves, and other components in fuel service, records of AVO checks and maintenance performed to show compliance with Special Condition No. 27.

Attachment A

Permit Numbers 130051, PSDTX1450, and GHGPSDTX131

Planned Maintenance Activities						
Planned Maintenance Activity	EPN	Emissions				
		NO_x	CO	VOC	PM	SO_2
Combustion optimization[1]	CT1 - CT4	X	X	X	X	X
Turbine washing online[2]	CT1 - CT4				X	
Turbine washing offline[3]	CT1 - CT4			X		
Air intake filter maintenance[4]	MSSFUG				X	
Gaseous fuel venting[5]	MSSFUG			X		
Water-based washing	MSSFUG			X		
Management of sludge from pits, ponds, sumps, and water conveyances[6]	MSSFUG			X		
Organic chemical usage	MSSFUG			X		
Inspection, repair, replacement, adjusting, testing, and calibration of analytical equipment, process instruments including sight glasses, meters, gauges, CEMS, or PEMS	MSSFUG	X	X	X		X
Small equipment and component in VOC service repair and replacement[7]	MSSFUG			X		
Maintenance of storage vessels storing materials with a vapor pressure <0.5 psia	MSSFUG			X		

Date:_________

1 Includes, but is not limited to, (1) leak or operability checks (e.g. turbine over-speed test, troubleshooting), (ii) balancing, and (iii) tuning activities that occur during seasonal tuning or after completion of initial construction, combustor change-out, major repair, combustor maintenance, or other similar circumstances.

2 Involves the use of water only.

3 May involve organic solutions or solvents.

4 Includes, but is not limited to, combustion turbine air intake filters.

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

6 Includes, but is not limited to, management by vacuum truck/dewatering of materials in open pits, ponds, sumps, tanks, and other closed/open vessels. Materials include water and sludge materials containing miscellaneous VOCs such as diesel, lube oil, and other waste oils.

7 Includes, but is not limited to, (i) repair/replacement of pumps, compressors, valves, pipes, flanges, transport lines, filters, and screens in natural gas, diesel oil, and lube oil service, (ii) vehicle and mobile equipment maintenance that may involve VOC emissions, such as oil changes, transmission service, and hydraulic system service.

Emission Sources - Maximum Allowable Emission Rates

Permit Numbers 130051 and PSDTX1450

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.

(GE 7FA.05 Option)

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT1	Unit 1 GE 7FA.05 Gas Turbine	NG	Normal	NO_x	69.7	156
				CO	42.4	153
				VOC	5.4	21.3
				PM	14	15.8
				PM_{10}	14	
				$PM_{2.5}$	14	
				SO_2	30.5	8.6
				H_2SO_4	4.7	1.3
			MSS	NO_x	72	(7)
				CO	771	
				VOC	134	
				PM	10.1	
				PM_{10}	10.1	
				$PM_{2.5}$	10.1	
				SO_2	5.5	
				H_2SO_4	0.8	
		FO	Normal and MSS	NO_x	371	(7)
			Normal	CO	107	
				VOC	3.3	
			Normal and MSS	PM	9.8	
				PM_{10}	9.8	
				$PM_{2.5}$	9.8	
				SO_2	3.5	
				H_2SO_4	0.5	
			MSS	CO	864	
				VOC	39	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT2	Unit 2 GE 7FA.05 Gas Turbine	NG	Normal	NO_x	69.7	156
				CO	42.4	153
				VOC	5.4	21.3
				PM	14	15.8
				PM_{10}	14	
				$PM_{2.5}$	14	
				SO_2	30.5	8.6
				H_2SO_4	4.7	1.3
			MSS	NO_x	72	(7)
				CO	771	
				VOC	134	
				PM	10.1	
				PM_{10}	10.1	
				$PM_{2.5}$	10.1	
				SO_2	5.5	
				H_2SO_4	0.8	
		FO	Normal and MSS	NO_x	371	(7)
			Normal	CO	107	
				VOC	3.3	
			Normal and MSS	PM	9.8	
				PM_{10}	9.8	
				$PM_{2.5}$	9.8	
				SO_2	3.5	
				H_2SO_4	0.5	
			MSS	CO	864	
				VOC	39	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT3	Unit 3 GE 7FA.05 Gas Turbine	NG	Normal	NO_x	69.7	156
				CO	42.4	153
				VOC	5.4	21.3
				PM	14	15.8
				PM_{10}	14	
				$PM_{2.5}$	14	
				SO_2	30.5	8.6
				H_2SO_4	4.7	1.3
			MSS	NO_x	72	(7)
				CO	771	
				VOC	134	
				PM	10.1	
				PM_{10}	10.1	
				$PM_{2.5}$	10.1	
				SO_2	5.5	
				H_2SO_4	0.8	
		FO	Normal and MSS	NO_x	371	(7)
			Normal	CO	107	
				VOC	3.3	
			Normal and MSS	PM	9.8	
				PM_{10}	9.8	
				$PM_{2.5}$	9.8	
				SO_2	3.5	
				H_2SO_4	0.5	
			MSS	CO	864	
				VOC	39	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT4	Unit 4 GE 7FA.05 Gas Turbine	NG	Normal	NO_x	69.7	156
				CO	42.4	153
				VOC	5.4	21.3
				PM	14	15.8
				PM_{10}	14	
				$PM_{2.5}$	14	
				SO_2	30.5	8.6
				H_2SO_4	4.7	1.3
			MSS	NO_x	72	(7)
				CO	771	
				VOC	134	
				PM	10.1	
				PM_{10}	10.1	
				$PM_{2.5}$	10.1	
				SO_2	5.5	
				H_2SO_4	0.8	
		FO	Normal and MSS	NO_x	371	(7)
			Normal	CO	107	
				VOC	3.3	
			Normal and MSS	PM	9.8	
				PM_{10}	9.8	
				$PM_{2.5}$	9.8	
				SO_2	3.5	
				H_2SO_4	0.5	
			MSS	CO	864	
				VOC	39	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT1	Unit 1 GE 7FA.04 Gas Turbine	NG	Normal	NO_x	62.6	140
				CO	38.1	127
				VOC	4.9	20.5
				PM	13.5	15.7
				PM_{10}	13.5	
				$PM_{2.5}$	13.5	
				SO_2	27.2	7.6
				H_2SO_4	4.2	1.2
			MSS	NO_x	65.5	(7)
				CO	592	
				VOC	134	
				PM	10.1	
				PM_{10}	10.1	
				$PM_{2.5}$	10.1	
				SO_2	4.9	
				H_2SO_4	0.8	
		FO	Normal and MSS	NO_x	333	(7)
			Normal	CO	96.5	
				VOC	3.1	
			Normal and MSS	PM	9.8	
				PM_{10}	9.8	
				$PM_{2.5}$	9.8	
				SO_2	3.2	
				H_2SO_4	0.5	
			MSS	CO	768	
			MSS	VOC	18	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT2	Unit 2 GE 7FA.04 Gas Turbine	NG	Normal	NO_x	62.6	140
				CO	38.1	127
				VOC	4.9	20.5
				PM	13.5	15.7
				PM_{10}	13.5	
				$PM_{2.5}$	13.5	
				SO_2	27.2	7.6
				H_2SO_4	4.2	1.2
			MSS	NO_x	65.5	(7)
				CO	592	
				VOC	134	
				PM	10.1	
				PM_{10}	10.1	
				$PM_{2.5}$	10.1	
				SO_2	4.9	
				H_2SO_4	0.8	
		FO	Normal and MSS	NO_x	333	(7)
			Normal	CO	96.5	
				VOC	3.1	
			Normal and MSS	PM	9.8	
				PM_{10}	9.8	
				$PM_{2.5}$	9.8	
				SO_2	3.2	
				H_2SO_4	0.5	
			MSS	CO	768	
			MSS	VOC	18	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT3	Unit 3 GE 7FA.04 Gas Turbine	NG	Normal	NO_x	62.6	140
				CO	38.1	127
				VOC	4.9	20.5
				PM	13.5	15.7
				PM_{10}	13.5	
				$PM_{2.5}$	13.5	
				SO_2	27.2	7.6
				H_2SO_4	4.2	1.2
			MSS	NO_x	65.5	(7)
				CO	592	
				VOC	134	
				PM	10.1	
				PM_{10}	10.1	
				$PM_{2.5}$	10.1	
				SO_2	4.9	
				H_2SO_4	0.8	
		FO	Normal and MSS	NO_x	333	(7)
			Normal	CO	96.5	
				VOC	3.1	
			Normal and MSS	PM	9.8	
				PM_{10}	9.8	
				$PM_{2.5}$	9.8	
				SO_2	3.2	
				H_2SO_4	0.5	
			MSS	CO	768	
			MSS	VOC	18	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates lbs/hr	Emission Rates TPY (6)
CT4	Unit 4 GE 7FA.04 Gas Turbine	NG	Normal	NO_x	62.6	140
				CO	38.1	127
				VOC	4.9	20.5
				PM	13.5	15.7
				PM_{10}	13.5	
				$PM_{2.5}$	13.5	
				SO_2	27.2	7.6
				H_2SO_4	4.2	1.2
			MSS	NO_x	65.5	(7)
				CO	592	
				VOC	134	
				PM	10.1	
				PM_{10}	10.1	
				$PM_{2.5}$	10.1	
				SO_2	4.9	
				H_2SO_4	0.8	
		FO	Normal and MSS	NO_x	333	(7)
			Normal	CO	96.5	
				VOC	3.1	
			Normal and MSS	PM	9.8	
				PM_{10}	9.8	
				$PM_{2.5}$	9.8	
				SO_2	3.2	
				H_2SO_4	0.5	
			MSS	CO	768	
			MSS	VOC	18	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT1	Unit 1 GE 7FA.03 Gas Turbine	NG	Normal	NO_x	61.4	139
				CO	37.4	127
				VOC	4.8	20.3
				PM	13.3	15.7
				PM_{10}	13.3	15.7
				$PM_{2.5}$	13.3	15.7
				SO_2	26.3	7.4
				H_2SO_4	4.0	1.1
			MSS	NO_x	65.5	(7)
				CO	592	
				VOC	134	
				PM	10.0	
				PM_{10}	10.0	
				$PM_{2.5}$	10.0	
				SO_2	4.7	
				H_2SO_4	0.7	
		FO	Normal and MSS	NO_x	338	(7)
			Normal	CO	98.1	
				VOC	3.1	
			Normal and MSS	PM	9.8	
				PM_{10}	9.8	
				$PM_{2.5}$	9.8	
				SO_2	3.1	
				H_2SO_4	0.5	
			MSS	CO	768	
				VOC	18	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT2	Unit 2 GE 7FA.03 Gas Turbine	NG	Normal	NO_x	61.4	139
				CO	37.4	127
				VOC	4.8	20.3
				PM	13.3	15.7
				PM_{10}	13.3	15.7
				$PM_{2.5}$	13.3	15.7
				SO_2	26.3	7.4
				H_2SO_4	4.0	1.1
			MSS	NO_x	65.5	(7)
				CO	592	
				VOC	134	
				PM	10.0	
				PM_{10}	10.0	
				$PM_{2.5}$	10.0	
				SO_2	4.7	
				H_2SO_4	0.7	
		FO	Normal and MSS	NO_x	338	(7)
			Normal	CO	98.1	
				VOC	3.1	
			Normal and MSS	PM	9.8	
				PM_{10}	9.8	
				$PM_{2.5}$	9.8	
				SO_2	3.1	
				H_2SO_4	0.5	
			MSS	CO	768	
				VOC	18	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT3	Unit 3 GE 7FA.03 Gas Turbine	NG	Normal	NO_x	61.4	139
				CO	37.4	127
				VOC	4.8	20.3
				PM	13.3	15.7
				PM_{10}	13.3	15.7
				$PM_{2.5}$	13.3	15.7
				SO_2	26.3	7.4
				H_2SO_4	4.0	1.1
			MSS	NO_x	65.5	(7)
				CO	592	
				VOC	134	
				PM	10.0	
				PM_{10}	10.0	
				$PM_{2.5}$	10.0	
				SO_2	4.7	
				H_2SO_4	0.7	
		FO	Normal and MSS	NO_x	338	(7)
			Normal	CO	98.1	
				VOC	3.1	
			Normal and MSS	PM	9.8	
				PM_{10}	9.8	
				$PM_{2.5}$	9.8	
				SO_2	3.1	
				H_2SO_4	0.5	
			MSS	CO	768	
				VOC	18	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT4	Unit 4 GE 7FA.03 Gas Turbine	NG	Normal	NO_x	61.4	139
				CO	37.4	127
				VOC	4.8	20.3
				PM	13.3	15.7
				PM_{10}	13.3	15.7
				$PM_{2.5}$	13.3	15.7
				SO_2	26.3	7.4
				H_2SO_4	4.0	1.1
			MSS	NO_x	65.5	(7)
				CO	592	
				VOC	134	
				PM	10.0	
				PM_{10}	10.0	
				$PM_{2.5}$	10.0	
				SO_2	4.7	
				H_2SO_4	0.7	
		FO	Normal and MSS	NO_x	338	(7)
			Normal	CO	98.1	
				VOC	3.1	
			Normal and MSS	PM	9.8	
				PM_{10}	9.8	
				$PM_{2.5}$	9.8	
				SO_2	3.1	
				H_2SO_4	0.5	
			MSS	CO	768	
				VOC	18	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates lbs/hr	Emission Rates TPY (6)
CT1	Unit 1 Siemens SGT6-5000F(5)ee Gas Turbine	NG	Normal	NO_x	75.0	146
				CO	25.2	210
				VOC	1.8	22.7
				PM	13.7	18.4
				PM_{10}	13.7	
				$PM_{2.5}$	13.7	
				SO_2	32.3	9.3
				H_2SO_4	4.9	1.4
			MSS	NO_x	139	(7)
				CO	1,531	
				VOC	180	
				PM	9.7	
				PM_{10}	9.7	
				$PM_{2.5}$	9.7	
				SO_2	5.8	
				H_2SO_4	0.9	
		FO	Normal	NO_x	217	(7)
				CO	53	
				VOC	3.0	
			Normal and MSS	PM	30.5	
				PM_{10}	30.5	
				$PM_{2.5}$	30.5	
				SO_2	3.4	
				H_2SO_4	0.5	
			MSS	NO_x	270	
				CO	3,180	
				VOC	374	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT2	Unit 2 Siemens SGT6-5000F(5)ee Gas Turbine	NG	Normal	NO_x	75.0	146
				CO	25.2	210
				VOC	1.8	22.7
				PM	13.7	18.4
				PM_{10}	13.7	
				$PM_{2.5}$	13.7	
				SO_2	32.3	9.3
				H_2SO_4	4.9	1.4
			MSS	NO_x	139	(7)
				CO	1,531	
				VOC	180	
				PM	9.7	
				PM_{10}	9.7	
				$PM_{2.5}$	9.7	
				SO_2	5.8	
				H_2SO_4	0.9	
		FO	Normal	NO_x	217	(7)
				CO	53	
				VOC	3.0	
			Normal and MSS	PM	30.5	
				PM_{10}	30.5	
				$PM_{2.5}$	30.5	
				SO_2	3.4	
				H_2SO_4	0.5	
			MSS	NO_x	270	
				CO	3,180	
				VOC	374	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT3	Unit 3 Siemens SGT6-5000F(5)ee Gas Turbine	NG	Normal	NO_x	75.0	146
				CO	25.2	210
				VOC	1.8	22.7
				PM	13.7	18.4
				PM_{10}	13.7	
				$PM_{2.5}$	13.7	
				SO_2	32.3	9.3
				H_2SO_4	4.9	1.4
			MSS	NO_x	139	(7)
				CO	1,531	
				VOC	180	
				PM	9.7	
				PM_{10}	9.7	
				$PM_{2.5}$	9.7	
				SO_2	5.8	
				H_2SO_4	0.9	
		FO	Normal	NO_x	217	(7)
				CO	53	
				VOC	3.0	
			Normal and MSS	PM	30.5	
				PM_{10}	30.5	
				$PM_{2.5}$	30.5	
				SO_2	3.4	
				H_2SO_4	0.5	
			MSS	NO_x	270	
				CO	3,180	
				VOC	374	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Operational Mode (4)	Air Contaminant Name (5)	Emission Rates	
					lbs/hr	TPY (6)
CT4	Unit 4 Siemens SGT6-5000F(5)ee Gas Turbine	NG	Normal	NO_x	75.0	146
				CO	25.2	210
				VOC	1.8	22.7
				PM	13.7	18.4
				PM_{10}	13.7	
				$PM_{2.5}$	13.7	
				SO_2	32.3	9.3
				H_2SO_4	4.9	1.4
			MSS	NO_x	139	(7)
				CO	1,531	
				VOC	180	
				PM	9.7	
				PM_{10}	9.7	
				$PM_{2.5}$	9.7	
				SO_2	5.8	
				H_2SO_4	0.9	
		FO	Normal	NO_x	217	(7)
				CO	53	
				VOC	3.0	
			Normal and MSS	PM	30.5	
				PM_{10}	30.5	
				$PM_{2.5}$	30.5	
				SO_2	3.4	
				H_2SO_4	0.5	
			MSS	NO_x	270	
				CO	3,180	
				VOC	374	

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (5)	Emission Rates	
			lbs/hr	TPY (6)
EDG-1	1 MW Emergency Generator Unit 1 Caterpillar C32 Diesel Engine	NO_x	14.7	0.73
		CO	0.39	0.02
		VOC	0.03	<0.01
		PM	0.05	<0.01
		PM_{10}	0.05	<0.01
		$PM_{2.5}$	0.05	<0.01
		SO_2	0.02	<0.01
EDG-2	1 MW Emergency Generator Unit 2 Caterpillar C32 Diesel Engine	NO_x	14.7	0.73
		CO	0.39	0.02
		VOC	0.03	<0.01
		PM	0.05	<0.01
		PM_{10}	0.05	<0.01
		$PM_{2.5}$	0.05	<0.01
		SO_2	0.02	<0.01
FWP-1	Fire Water Pump 260 horsepower Diesel Engine	NO_x	1.7	0.09
		CO	1.5	0.07
		VOC	0.11	<0.01
		PM	0.09	<0.01
		PM_{10}	0.09	<0.01
		$PM_{2.5}$	0.09	<0.01
		SO_2	<0.01	<0.01
TNK-1	EDG1 Diesel Fuel Storage Tank 1	VOC	0.12	<0.01
TNK-2	EDG2 Diesel Fuel Storage Tank 2	VOC	0.12	<0.01
TNK-3	FWP Diesel Fuel Storage Tank	VOC	0.03	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (5)	Emission Rates	
			lbs/hr	TPY (6)
TNK-4	Fuel Oil Storage Tank	VOC	2.11	0.05
TNK-5	Fuel Oil Storage Tank	VOC	2.11	0.05
CT1LOV	Unit 1 Lube Oil Vent	VOC	<0.01	0.01
		PM	<0.01	0.01
		PM_{10}	<0.01	0.01
		$PM_{2.5}$	<0.01	0.01
CT2LOV	Unit 2 Lube Oil Vent	VOC	<0.01	0.01
		PM	<0.01	0.01
		PM_{10}	<0.01	0.01
		$PM_{2.5}$	<0.01	0.01
CT3LOV	Unit 3 Lube Oil Vent	VOC	<0.01	0.01
		PM	<0.01	0.01
		PM_{10}	<0.01	0.01
		$PM_{2.5}$	<0.01	0.01
CT4LOV	Unit 4 Lube Oil Vent	VOC	<0.01	0.01
		PM	<0.01	0.01
		PM_{10}	<0.01	0.01
		$PM_{2.5}$	<0.01	0.01
NGF	Natural Gas Component Fugitives (8)	VOC	0.04	0.18
LOF	Lube Oil Component Fugitives (8)	VOC	0.66	2.91
FOF	Fuel Oil Component Fugitives (8)	VOC	1.03	4.50

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (5)	Emission Rates	
			lbs/hr	TPY (6)
MSSFUG	Planned Maintenance Activity Fugitives (8)	NO_x	0.03	<0.01
		VOC	110	3.78
		PM	<0.01	<0.01
		PM_{10}	<0.01	<0.01
		$PM_{2.5}$	<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) NG - natural gas
FO - fuel oil
(4) Normal operation is defined in Special Condition No. 4. Maintenance, startup, and shutdown (MSS) emissions are described in Special Condition No. 11.
(5) NO_x - total oxides of nitrogen
CO - carbon monoxide
VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code (30 TAC) § 101.1
PM - particulate matter emissions, as defined in 30 TAC § 101.1, including PM_{10}, $PM_{2.5}$ and H_2SO_4
PM_{10} - particulate matter emissions equal to or less than 10 microns in diameter, including $PM_{2.5}$ and H_2SO_4
$PM_{2.5}$ - direct particulate matter emissions equal to or less than 2.5 microns in diameter, including H_2SO_4
SO_2 - sulfur dioxide
H_2SO_4 - sulfuric acid
(6) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period. Annual emission rates for each source include planned MSS emissions.
(7) The TPY emission rates for CTs under natural gas firing, normal operational mode are total limits including MSS and fuel oil backup.
(8) Emission rate is an estimate and is enforceable through compliance with applicable special conditions and permit application representations.

Date: XXXXX, 2015

Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPSDTX131

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

(GE 7FA.05 Option)

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Fuel (3)	Air Contaminant Name (4)	Emission Rates
				TPY (5)
CT1	Unit 1 GE 7FA.05 Gas Turbine	NG	CO_2	401,620
			CH_4	7.45
			N_2O	0.74
		FO	CO_2	56,845
			CH_4	2.32
			N_2O	0.46
		Total (NG,FO)	CO_2e	459,069
CT2	Unit 2 GE 7FA.05 Gas Turbine	NG	CO_2	401,620
			CH_4	7.45
			N_2O	0.74
		FO	CO_2	56,845
			CH_4	2.32
			N_2O	0.46
		Total (NG,FO)	CO_2e	459,069
CT3	Unit 3 GE 7FA.05 Gas Turbine	NG	CO_2	401,620
			CH_4	7.45
			N_2O	0.74
		FO	CO_2	56,845
			CH_4	2.32
			N_2O	0.46
		Total (NG,FO)	CO_2e	459,069
CT4	Unit 4 GE 7FA.05 Gas Turbine	NG	CO_2	401,620
			CH_4	7.45
			N_2O	0.74
		FO	CO_2	56,845
			CH_4	2.32
			N_2O	0.46
		Total (NG,FO)	CO_2e	459,069

(GE 7FA.04 Option)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Air Contaminant Name (4)	Emission Rates TPY (5)
CT1	Unit 1 GE 7FA.04 Gas Turbine	NG	CO_2	358,618
			CH_4	6.65
			N_2O	0.67
		FO	CO_2	52,235
			CH_4	2.13
			N_2O	0.43
		Total (NG,FO)	CO_2e	411,398
CT2	Unit 2 GE 7FA.04 Gas Turbine	NG	CO_2	358,618
			CH_4	6.65
			N_2O	0.67
		FO	CO_2	52,235
			CH_4	2.13
			N_2O	0.43
		Total (NG,FO)	CO_2e	411,398
CT3	Unit 3 GE 7FA.04 Gas Turbine	NG	CO_2	358,618
			CH_4	6.65
			N_2O	0.67
		FO	CO_2	52,235
			CH_4	2.13
			N_2O	0.43
		Total (NG,FO)	CO_2e	411,398
CT4	Unit 4 GE 7FA.04 Gas Turbine	NG	CO_2	358,618
			CH_4	6.65
			N_2O	0.67
		FO	CO_2	52,235
			CH_4	2.13
			N_2O	0.43
		Total (NG,FO)	CO_2e	411,398

(GE 7FA.03 Option)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Air Contaminant Name (4)	Emission Rates
				TPY (5)
CT1	Unit 1 GE 7FA.03 Gas Turbine	NG	CO_2	345,656
			CH_4	6.41
			N_2O	0.64
		FO	CO_2	50,601
			CH_4	2.06
			N_2O	0.41
		Total (NG,FO)	CO_2e	396,783
CT2	Unit 2 GE 7FA.03 Gas Turbine	NG	CO_2	345,656
			CH_4	6.41
			N_2O	0.64
		FO	CO_2	50,601
			CH_4	2.06
			N_2O	0.41
		Total (NG,FO)	CO_2e	396,783
CT3	Unit 3 GE 7FA.03 Gas Turbine	NG	CO_2	345,656
			CH_4	6.41
			N_2O	0.64
		FO	CO_2	50,601
			CH_4	2.06
			N_2O	0.41
		Total (NG,FO)	CO_2e	396,783
CT4	Unit 4 GE 7FA.03 Gas Turbine	NG	CO_2	345,656
			CH_4	6.41
			N_2O	0.64
		FO	CO_2	50,601
			CH_4	2.06
			N_2O	0.41
		Total (NG,FO)	CO_2e	396,783

(Siemens SGT6-5000F Option)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Fuel (3)	Air Contaminant Name (4)	Emission Rates TPY (5)
CT1	Unit 1 Siemens SGT6-5000F(5)ee Gas Turbine	NG	CO_2	418,903
			CH_4	7.77
			N_2O	0.78
		FO	CO_2	56,202
			CH_4	2.29
			N_2O	0.46
		Total (NG,FO)	CO_2e	475,724
CT2	Unit 2 Siemens SGT6-5000F(5)ee Gas Turbine	NG	CO_2	418,903
			CH_4	7.77
			N_2O	0.78
		FO	CO_2	56,202
			CH_4	2.29
			N_2O	0.46
		Total (NG,FO)	CO_2e	475,724
CT3	Unit 3 Siemens SGT6-5000F(5)ee Gas Turbine	NG	CO_2	418,903
			CH_4	7.77
			N_2O	0.78
		FO	CO_2	56,202
			CH_4	2.29
			N_2O	0.46
		Total (NG,FO)	CO_2e	475,724
CT4	Unit 4 Siemens SGT6-5000F(5)ee Gas Turbine	NG	CO_2	418,903
			CH_4	7.77
			N_2O	0.78
		FO	CO_2	56,202
			CH_4	2.29
			N_2O	0.46
		Total (NG,FO)	CO_2e	475,724

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (4)	Emission Rates
			TPY (5)
EDG-1	1 MW Emergency Generator Unit 1 Caterpillar C32 Diesel Engine	CO_2	80.9
		CH_4	<0.01
		N_2O	<0.01
		CO_2e	81.2
EDG-2	1 MW Emergency Generator Unit 2 Caterpillar C32 Diesel Engine	CO_2	80.9
		CH_4	<0.01
		N_2O	<0.01
		CO_2e	81.2
FWP-1	Fire Water Pump 260 horsepower Diesel Engine	CO_2	14.3
		CH_4	<0.01
		N_2O	<0.01
		CO_2e	14.3
NGF	Natural Gas Component Fugitives (6)	CO_2	0.12
		CH_4	8.01
		CO_2e	200.4
MSSFUG	Planned Maintenance Activity Fugitives (6)	CO_2	<0.01
		CH_4	<0.01
		CO_2e	0.1
SF6-FUG	Fugitives: Sulfur Hexafluoride from Circuit Breakers (6)	SF_6	<0.01
		CO_2e	8.6

(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) NG - natural gas; FO - fuel oil
(4) CO_2 - carbon dioxide
CH_4 - methane
N_2O - nitrous oxide
SF_6 - sulfur hexafluoride
CO_2e - carbon dioxide equivalents, based on the following Global Warming Potentials from 40 CFR Part 98, Subpart A, Table A-1, effective January 1, 2015:
CO_2 (1), CH_4 (25), N_2O (298), SF_6 (22,800)
(5) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period. Annual emission limits include both normal and maintenance, startup, and shutdown (MSS) emissions.
(6) Fugitive emission rates are estimates and are enforceable through compliance with applicable special conditions and permit application representations.

Date: XXXX, 2015

Texas Commission on Environmental Quality
Air Quality Permit

A Permit Is Hereby Issued To
Brazos Electric Power Cooperative, Inc.
Authorizing the Construction and Operation of the
Hill County Generation Facility
Located near **Grandview, Hill County, Texas**
Latitude 32° 14′ 28″ Longitude 97° 04′ 17″

Permits: 130051, PSDTX1450, and GHGPSDTX131

Issuance Date: xxxx

Expiration Date: xxxx

For the Commission

1. **Facilities** covered by this permit shall be constructed and operated as specified in the application for the permit. All representations regarding construction plans and operation procedures contained in the permit application shall be conditions upon which the permit is issued. Variations from these representations shall be unlawful unless the permit holder first makes application to the Texas Commission on Environmental Quality (commission) Executive Director to amend this permit in that regard and such amendment is approved. [Title 30 Texas Administrative Code (TAC) Section 116.116 (30 TAC § 116.116)] [1]
2. **Voiding of Permit**. A permit or permit amendment is automatically void if the holder fails to begin construction within 18 months of the date of issuance, discontinues construction for more than 18 months prior to completion, or fails to complete construction within a reasonable time. Upon request, the executive director may grant an 18-month extension. Before the extension is granted the permit may be subject to revision based on best available control technology, lowest achievable emission rate, and netting or offsets as applicable. One additional extension of up to 18 months may be granted if the permit holder demonstrates that emissions from the facility will comply with all rules and regulations of the commission, the intent of the Texas Clean Air Act (TCAA), including protection of the public's health and physical property; and (b)(1)the permit holder is a party to litigation not of the permit holder's initiation regarding the issuance of the permit; or (b)(2) the permit holder has spent, or committed to spend, at least 10 percent of the estimated total cost of the project up to a maximum of $5 million. A permit holder granted an extension under subsection (b)(1) of this section may receive one subsequent extension if the permit holder meets the conditions of subsection (b)(2) of this section. [30 TAC § 116.120]
3. **Construction Progress**. Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office of the commission not later than 15 working days after occurrence of the event. [30 TAC § 116.115(b)(2)(A)]
4. **Start-up Notification**. The appropriate air program regional office shall be notified prior to the commencement of operations of the facilities authorized by the permit in such a manner that a representative of the commission may be present. The permit holder shall provide a separate notification for the commencement of operations for each unit of phased construction, which may involve a series of units commencing operations at different times. Prior to operation of the facilities authorized by the permit, the permit holder shall identify the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program). [30 TAC § 116.115(b)(2)(B)]
5. **Sampling Requirements**. If sampling is required, the permit holder shall contact the commission's Office of Compliance and Enforcement prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The permit holder is also responsible for providing sampling

facilities and conducting the sampling operations or contracting with an independent sampling consultant. [30 TAC § 116.115(b)(2)(C)]

6. **Equivalency of Methods.** The permit holder must demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the permit. Alternative methods shall be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the permit. [30 TAC § 116.115(b)(2)(D)]
7. **Recordkeeping.** The permit holder shall maintain a copy of the permit along with records containing the information and data sufficient to demonstrate compliance with the permit, including production records and operating hours; keep all required records in a file at the plant site. If, however, the facility normally operates unattended, records shall be maintained at the nearest staffed location within Texas specified in the application; make the records available at the request of personnel from the commission or any air pollution control program having jurisdiction in a timely manner; comply with any additional recordkeeping requirements specified in special conditions in the permit; and retain information in the file for at least two years following the date that the information or data is obtained. [30 TAC § 116.115(b)(2)(E)]
8. **Maximum Allowable Emission Rates**. The total emissions of air contaminants from any of the sources of emissions must not exceed the values stated on the table attached to the permit entitled "Emission Sources--Maximum Allowable Emission Rates." [30 TAC § 116.115(b)(2)(F)] [1]
9. **Maintenance of Emission Control**. The permitted facilities shall not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. The permit holder shall provide notification in accordance with 30 TAC §101.201, 101.211, and 101.221 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements; and Operational Requirements). [30 TAC§ 116.115(b)(2)(G)]
10. **Compliance with Rules**. Acceptance of a permit by an applicant constitutes an acknowledgment and agreement that the permit holder will comply with all rules and orders of the commission issued in conformity with the TCAA and the conditions precedent to the granting of the permit. If more than one state or federal rule or regulation or permit condition is applicable, the most stringent limit or condition shall govern and be the standard by which compliance shall be demonstrated. Acceptance includes consent to the entrance of commission employees and agents into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the permit. [30 TAC § 116.115(b)(2)(H)]
11. **This** permit may not be transferred, assigned, or conveyed by the holder except as provided by rule. [30 TAC § 116.110(e)]
12. **There** may be additional special conditions attached to a permit upon issuance or modification of the permit. Such conditions in a permit may be more restrictive than the requirements of Title 30 of the Texas Administrative Code. [30 TAC § 116.115(c)]
13. **Emissions** from this facility must not cause or contribute to "air pollution" as defined in Texas Health and Safety Code (THSC) §382.003(3) or violate THSC § 382.085. If the executive director determines that such a condition or violation occurs, the holder shall implement additional abatement measures as necessary to control or prevent the condition or violation.
14. **The** permit holder shall comply with all the requirements of this permit. Emissions that exceed the limits of this permit are not authorized and are violations of this permit. [1]

[1] Please be advised that the requirements of this provision of the general conditions may not be applicable to greenhouse gas emissions.

Preliminary Determination Summary

Brazos Electric Cooperative, Incorporated
Hill County Generating Facility

Permit Numbers 130051, PSDTX1450, and GHGPSDTX131

I. Applicant

Brazos Electric Cooperative, Incorporated
7616 Bagby Avenue
Waco, Texas 76712-6924

II. Project Location

The proposed Hill County Generating Facility (HCGF) is located at 3750 Farm-to-Market Road 66, near the city of Grandview, in Hill County, Texas 76050.

III. Project Description

Brazos Electric Cooperative, Incorporated (Brazos) proposes to construct a new simple cycle electric generating facility to provide peaking electric power to the grid. The major equipment consists of four, natural gas-fired combustion turbines (CTs) powering electric generators (CTGs). Four CT/CTG models are being considered for selection: General Electric (GE) 7FA.03, GE 7FA.04, GE 7FA.05, and Siemens SGT6-5000F(5)ee. The total electric output of the four CTGs will be between 684 MW and 928 MW, depending on which model is chosen. Although natural gas will be the normal fuel, the proposed permit allows limited CT operation on ultra-low sulfur diesel (ULSD) fuel oil as an emergency backup fuel.

In addition to the major equipment, an electric generating facility requires support equipment. Emissions from this equipment are minor. The support equipment includes: two 1 MW emergency diesel engine generators, a 260 horsepower emergency diesel engine fire water pump, three small diesel fuel storage tanks for the emergency diesel engines, and two larger diesel fuel tanks for CT emergency use.

There are several small sources of emissions associated with plant operations, including lube oil vents for the CTs and CTGs and fugitive emissions from several types of equipment. Fugitive emissions occur from piping components in natural gas, diesel, and lube oil service; various planned maintenance activities; and the sulfur hexafluoride (SF_6)-insulated main circuit breakers.

IV. Emissions

The proposed HCGF's maximum annual emissions of federally regulated new source review (FNSR) pollutants subject to review by the Texas Commission on Environmental Quality (TCEQ), in tons per year (tpy), are shown in Tables IV-1 and IV-2. The tables show the highest emissions allowed for individual pollutants, based on the highest emission rates for individual pollutants among the four CT models under consideration. The actual maximum allowable emission rates will be somewhat lower after Brazos chooses the CT model and the three unchosen CT emission cases are removed from the permit maximum allowable emission rate table (MAERT), as required by Special Condition No. 4.A.(2) of the draft permit.

Table IV-1 shows both criteria air pollutants, for which National Ambient Air Quality Standards (NAAQS) have been established by the U.S. Environmental Protection Agency (EPA), and pollutants which contribute to ambient levels of criteria pollutants. The pollutants on Table IV-1 for which NAAQS have been established are: nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM), PM less than 10 microns in average diameter (PM_{10}), PM less than 2.5 microns in average diameter ($PM_{2.5}$), and sulfur dioxide (SO_2). The pollutants which contribute to ambient levels of criteria pollutants are NO_x and volatile organic compounds (VOC), ingredients in the formation of the criteria pollutant ozone, and sulfuric acid (H_2SO_4), a contributor to the ambient level of $PM_{2.5}$.

Table IV-1. FNSR pollutants, tpy

NO_x	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2	H_2SO_4
625	840	103	74	74	74	37	5.6

The PM_{10} and $PM_{2.5}$ emissions represent size fractions of PM, and are regulated separately with respect to allowable concentrations in the air around the plant. However, because the exhaust PM from CTs and engines is all submicron, with an average diameter less than 1 x (10^{-6}) meter, 100% of the PM emissions fall in each of the regulated size ranges. The predicted concentrations of these pollutants are discussed in Section VII. The listed PM, PM_{10}, and $PM_{2.5}$ emissions include solid (filterable) and liquid (condensible) material. As a submicron liquid material, the H_2SO_4 emissions are a subset of each of the PM size categories.

The emissions from routine maintenance, startup, and shutdown (MSS) activities are part of the permit application and have been reviewed. Where MSS rates are higher than normal operation rates, the CTs have separate hourly emission limits for normal and MSS operations. The annual emission limits for each CT combine normal and MSS operation emissions into a single limit.

The Prevention of Significant Deterioration (PSD) rules were modified to include greenhouse gas (GHG) emissions starting in 2011. Carbon dioxide (CO_2) is the primary GHG constituent from fossil fuel electric generating facilities. Much smaller quantities of methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6) are typically emitted. PSD rule applicability is based on a project's total carbon dioxide equivalents (CO_2e), where individual species of GHG are weighted according to their global warming potential (GWP) relative to CO_2 (GWP of 1) before totaling. The current EPA-defined GWPs are: CH_4 – 25; N_2O - 298, and SF_6 - 22,800.

Table IV-2 shows the proposed levels of GHG emissions and CO_2e based on Siemens SGT6-5000F CTs, the largest CT model and highest GHG emitter among the four CT models under consideration.

Table IV-2. Greenhouse gas pollutants, tpy

CO_2	CH_4	N_2O	SF_6	CO_2e
1,900,596	48	5	<1	1,903,000

V. Federal Applicability

The United States Environmental Protection Agency (EPA) classifies Hill County as "unclassifiable/attainment" or "better than national standards" for the criteria pollutants identified in Table IV-1. Because the ambient air in the county where the facility will be located is considered to attain the NAAQS, nonattainment rules do not apply to the HCGF project.

The EPA's PSD rules require Brazos to obtain a federal PSD permit. PSD applies to major new or modified sources located in attainment areas. The main objective of the PSD permit program for criteria air pollutants is to prevent areas with clean air from degrading to the limit of the NAAQS. Additionally, a PSD project may not cause or contribute to a condition of nonattainment of a NAAQS. A PSD new major source includes projects such as the HCGF that have the potential to emit 250 tpy or more of a non-GHG FNSR pollutant. As shown in Table IV-1, the HCGF has proposed emissions above 250 tpy of NO_x and CO, either of which is sufficient to trigger PSD review. Once PSD review is required, other non-GHG FNSR pollutants become subject to PSD review at defined "significant" amounts, including 25 tpy of PM, 15 tpy of PM_{10}, 10 tpy of direct $PM_{2.5}$, 40 tpy of VOC, 40 tpy of SO_2, and 7 tpy of H_2SO_4. Based on these thresholds, the HCGF is subject to PSD review for NO_x, CO, $PM/PM_{10}/PM_{2.5}$, and VOC, but not SO_2 or H_2SO_4.

Under the implementation of the PSD rules since the June 23, 2014 Supreme Court decision, *Utility Air Resources Group v. EPA, 134 S. Ct. 2427*, GHG review is only required if a project is already subject to PSD review for non-GHG pollutants. Because the HCGF's proposed non-GHG pollutants are subject to PSD review and, as shown in Table IV-2, the proposed GHG emissions are above the 75,000 tpy PSD significant level for CO_2e, PSD review is also required for GHG.

VI. Control Technology Review

A key element of the PSD permit is the requirement to apply best available control technology (BACT) for each regulated pollutant emitted in significant amounts. The applicant is required to provide the information necessary for the reviewing authority to independently evaluate the proposed BACT. In addition to a review of control technology for continuous operations, startup and shutdown emissions are subject to BACT and must also be evaluated.

As part of the BACT review process, the Texas Commission on Environmental Quality (TCEQ) evaluates information from the Environmental Protection Agency's (EPA's) RACT/BACT/LAER Clearinghouse (RBLC), on-going permitting in Texas and other states, and the TCEQ's continuing review of emissions control developments.

BACT for Criteria Pollutants

A. Simple Cycle CTs

NO_x Emissions

Normally, the CTs are natural gas fired. The CTs are equipped with dry low-NO_x (DLN) combustors to control NO_x emissions to 9 parts per million by volume dry (ppmvd) at 15% O_2 during normal operations. This limit is Tier I BACT for peaking units, according to the TCEQ's Gas Turbine BACT Requirements table. Searches of the EPA's RBLC for gas-fired CTs in simple cycle electric generating service were conducted by the applicant and the TCEQ permit reviewer. The lowest emission limits in the RBLC are based on the combination of DLN burners and selective catalytic reduction (SCR); the lowest emission limit is 2.5 ppmvd NO_x. The listed permits were issued for aero-derivative CTs, which are smaller than industrial "frame" CTs, and have exhaust temperatures low enough to reliably use SCR without additional exhaust cooling. The cost of SCR for these smaller CTs with lower exhaust temperature and flow rates has been found by the TCEQ to be economically reasonable and is Tier I BACT. However, the proposed HCGF relies on the sturdier, larger, and more common frame CTs. The frame CTs have higher exhaust temperatures than aero-derivative CTs. Outside of the RBLC, the permit reviewer is aware of the Marsh Landing power plant in Antioch, California, near San Francisco, which consists of four Siemens SGT6 5000F CTs in simple cycle peaking service. The permit limit of 2.5 ppmvd NO_x is met with DLN combustors and SCRs with air-cooled exhaust. The plant is located in an ozone nonattainment area, and the controls represent lowest achievable control technology rather than BACT. Based on cost evaluations of similar projects with limited annual hours of operation, such as the Xcel Energy Jones 4 simple cycle electric generating plant near Lubbock, Texas (TCEQ NSR Permit No. 98073), the control cost for SCR with air-cooled exhaust on SGT6 5000F CTs is above $100,000 per annual ton of NO_x removed. It should be noted that the major contributor to the high (poor) cost-effectiveness is due to the limited operation of peaking electric peaking plants. Most of the cost of SCR is capital cost, and the limited hours result in a lower potential of annual tons of NO_x to spread out that cost. Costs over $100,000/ton of NO_x reduced are considered economically unreasonable by the TCEQ and therefore do not constitute BACT. A practical aspect of these costs is that the Electric Reliability Council of Texas (ERCOT) area operates under a robust market system for electric generation in which only the lowest cost bidders are selected by ERCOT to operate. Based on the additional cost of electricity associated with SCR with air-cooled exhaust, Brazos would be unlikely to be able to operate the CTs enough to justify construction of the HCGF.

Brazos' proposed emission limit of 9.0 ppmvd on natural gas fuel is consistent with the BACT determinations in the RBLC for large frame CTs. This limit will be achieved with DLN, combustion technology that pre-mixes fuel and air to reduce thermal NO_x formation without the need for water or steam injection. Because the CTs are each limited to 2,920 hours per year of operation, based on a rolling 12-month period, installing SCR would not be economically reasonable. Recently issued permits in Texas for peaking CTs have a NO_x concentration limit of 9 ppmvd at 15% O_2. Therefore, the use of DLN to control NO_x emissions to 9 ppmvd at 15% O_2 is consistent with recently issued permits for similar facilities and is BACT for the CTs.

Brazos also proposes to operate the CTs on ULSD fuel oil as a backup fuel, for no more than 310 hours per year per CT.[1] The DLN combustors rely on premixing gaseous fuel. On oil fuel, an alternative control technology must be used. Brazos proposes to use water injection to control NO_x to 42 ppmvd for the GE CT models or 25 ppmvd for the Siemens CT. Based on the high cost of control, the use of SCR is not justified for fuel oil firing at 310 hours per year. The proposed limits are consistent with limits in the RBLC for simple cycle fuel oil firing. Water injection and the limited hours of operation represent BACT for the CTs while firing fuel oil.

CO Emissions:

With DLN (designed to increase oxidation of CO to CO_2) and operating the CTs according to good combustion practices, CO emissions will be controlled to 9 ppmvd at 15% O_2 (4 ppmvd for the Siemens model) during non-MSS operation. The RBLC reflects that for simple cycle CTs in electric generation service, lower CO emission limits have only been permitted in one case for very limited CTG load (Great River Energy's Elk River Station in Minnesota) and in permits for aero-derivative CTs in which catalytic oxidation was installed. Aero-derivative models typically have higher uncontrolled CO concentrations in the exhaust gas stream as compared to larger frame-type CTGs. Since the frame-type CTs proposed for this project will produce lower amounts of uncontrolled CO

[1]Brazos' proposed operational limitation is based on 300 hours of normal firing and about 10 hours of startup/shutdown firing. Special Condition No. 4.D.(1) expresses the ULSD firing limit per CT in the format of a MMBtu/yr, 12-month rolling average equivalent to about 310 hours per year at maximum firing rate on oil.

emissions, and are also each limited to a maximum of 2,920 hours of operation in a 12-month rolling period, the potential for CO emissions reduction is considerably decreased; therefore, the use of an oxidation catalyst is not economically reasonable. Recently issued peaking CT permits in Texas have been issued at 9 ppmvd at 15% O_2 (4 ppmvd for Siemens CTs). Therefore, the use of DLN and good combustion practices to control CO emissions to 9 ppmvd at 15% O_2 (4 ppmvd for the Siemens CTs) is consistent with recently issued permits for similar facilities and is BACT.

Water injection in the CTs (for NO_x control) while firing fuel oil can result in higher CO emissions. Based on vendor information, Brazos proposes CO emission limits of 20 ppmvd at 15% O_2 for the GE CTs and 10 ppmvd for the Siemens CTs. Based on the same reasons as for natural gas, low firing hours and relatively low total emissions making CO catalyst prohibitive, the proposed limits represent BACT for CO while firing fuel oil.

VOC Emissions:

Through maintenance of optimum combustion conditions and practices and firing the CTs with pipeline-quality natural gas, VOC emissions will be controlled to 2 ppmvd at 15% O_2 during normal load operations for the GE CT models and 1 ppmvd for the Siemens CT. For ULSD fuel oil, VOC emissions are proposed at 1.4 ppmvd at 15% O_2 during normal load operations for the GE CT models and at 1 ppmvd for the Siemens CT. The VOC concentrations proposed by the applicant are equal to or below the 2 ppmvd VOC concentration listed in TCEQ's Gas Turbine BACT Requirements Table for simple cycle CTs firing natural gas. BACT is satisfied.

$PM/PM_{10}/PM_{2.5}$ Emissions:
The CTs will be fired with pipeline-quality natural gas or ULSD fuel oil. Both of these fuels have very low ash and sulfur contents. A search of the RBLC database shows that no add-on controls are required for natural gas or ULSD fuel oil fired CTs to control $PM/PM_{10}/PM_{2.5}$ emissions. Therefore, this project satisfies BACT through the use of pipeline-quality natural gas and ULSD fuel and the application of good combustion controls.

Sulfur Compound Emissions (SO_2/H_2SO_4):
As discussed in Section V, the project's proposed SO_2 and H_2SO_4 emissions are below the PSD significant thresholds and are not subject to PSD review. Nonetheless, the TCEQ's state permit rules require BACT for all air contaminants; the following is a statement of the finding for the state permit review.

Emissions of SO_2 and H_2SO_4 from the CTs will occur from the oxidation of sulfur in the natural gas or fuel oil during combustion, with the majority of the sulfur converted to SO_2 and a small fraction converting to H_2SO_4. The CTs will be fired with pipeline-quality natural gas with a sulfur content not exceeding 5 grains sulfur per 100 dry standard cubic feet (gr/dscf) on an hourly average and 1.0 gr/dscf on an annual average, or ULSD fuel oil with a maximum sulfur content not exceeding 0.0015% by weight, which will minimize the formation of SO_2 and H_2SO_4. A search of the RBLC did not show any post-combustion SO_2 control technologies. The RBLC showed that limitations on the fuel sulfur content have been accepted as BACT for SO_2. Therefore, the use of natural gas and ULSD fuel oil with the sulfur contents listed above is BACT for SO_2 and H_2SO_4.

CT Planned MSS:
During periods of planned MSS, control devices and process equipment are operated outside the optimal range they were designed to work most effectively, and it is technically infeasible to meet the primary BACT emission rates.

Therefore, secondary BACT limits are necessary during these periods to minimize emissions. BACT will be achieved by minimizing the duration of the MSS events (consistent with standard operating procedures) to minimize the amount of time the equipment is outside the optimal performance mode and meeting the emission limitations on the MAERT.

Also, planned MSS activities must be performed using good air pollution control practices and safe operating practices to minimize emissions. The numerical emission limits in the draft permit reflect this analysis. Although the units may not meet the ppm by volume dry (ppmvd) limits during startup and shutdown, they will meet the mass emission limits (pounds per hour and tons per year) unless a separate limit was established, and startup and shutdown events will be limited by Special Condition No. 11. Typical startup and shutdown of the CTs are conducted in accordance with manufacturer's recommendations to minimize emissions and maximize efficiencies.

B. Lube Oil Vents
Mist eliminators will be installed on the CT lubrication oil vents to control oil emissions. Mist eliminators are BACT for lube oil vents.

C. Emergency Engines
An emergency generator and a firewater pump are proposed. BACT will be achieved through the installation of an engine which meets the requirements of 40 CFR 60, Subpart IIII. The engines will fire ULSD fuel, containing no more than 15 parts per million (ppm) sulfur by weight. Both the emergency generator and firewater pump engines are limited to 100 hours of non-emergency operation per year.

D. Fuel Oil Storage Tanks
Tanks to store ULSD fuel oil are proposed for the three emergency engines and for backup CT fuel. BACT is applied through the use of submerged fill pipes and white or aluminum exterior paint if the tank is exposed to the sun.

E. Fugitive Emissions
The fugitive emissions include VOC from the natural gas and ULSD fuel lines (EPNs NGF and FOF). Given the nature and quantity of the emissions, no control is BACT. Also, fugitive emissions are generated from MSS activities (EPN MSSFUG.) These MSS activities are conducted according to the turbine vendors and represent best practices for the type of equipment, and are considered BACT.

BACT for GHG Pollutants

A. Simple Cycle CTs
The control technology review for natural-gas fired simple cycle CTs in electric generation service showed only eight facilities in EPA's RBLC with BACT limits on CO_2e emissions in pounds/MW-hr. GHG BACT limits for those facilities vary from 1,276 to 1,707 lb CO_2e/MW-hr gross. For the six GHG permits issued by EPA Region 6 in 2014, GHG BACT limits varied from 1,100 to 1,393 lb CO_2/MW-hr gross. For four pending and two recently issued (November 2015) GHG permits with the TCEQ, GHG BACT limits for simple cycle CTs in electric generation service vary from 1,316 to 1,461 lb CO_2/MW-hr. All twenty of these CT projects use energy efficiency, good design, and combustion practices as BACT.

In addition to the GHG emission rates achieved in recent similar facilities across the United States, the applicant explored Carbon Capture and Sequestration (CCS).

CCS:
CCS consists of the separation and capture of CO_2 from the flue gas, pressurization of the captured CO_2, transportation of the CO_2 as a fluid via pipeline, and injection and long-term geologic storage. CCS technology does have the potential for practical application and, therefore, was considered an available control option. However, the very low concentration of CO_2 in the exhaust of natural gas-fired CTs (3-5%) makes CCS marginally applicable as a viable control technology given the cost of removing CO_2 from such a dilute stream.

The capture technologies applicable are pre-combustion systems, post combustion systems, and oxy-combustion systems. Pre-combustion systems are designed to separate CO_2 and hydrogen in a produced high pressure synthetic gas. Post-combustion systems are designed to separate CO_2 from the flue gas produced by the combustion process. Oxy-combustion systems use high-purity oxygen rather than air in the combustion process to produce a highly concentrated CO_2 stream.

Pre-combustion systems are not technically feasible for the HCGF, because they would fundamentally redefine the nature of the proposed source. Oxy-combustion systems are limited by the parasitic power required for oxygen production in a conventional air separation unit. In addition, the oxy-combustion process also requires a portion of the exhaust CO_2 stream to be cooled and recycled in the combustion chamber for mass and temperature control. These capture systems are associated with high energy penalties.

CCS technology is currently in various stages of development and is not commercially available. There have been no CCS demonstration projects to date (and none planned) for natural gas-fired simple cycle CT facilities. Therefore, although CCS was identified as an available control option, CCS technology is not considered technically feasible for the proposed natural gas-fired simple cycle CTGs at the HCGF and is not further considered in the BACT analysis.

Design for energy efficiency and good combustion practices:
The applicant proposed GHG emission rates based on CT vendor data, and design for energy efficiency and good combustion practices. CTs operating under those optimal conditions are expected to meet the following emission limits:

Table VI-1. Output-Specific CT GHG BACT Limits

CT Model	GHG BACT Emission Limits
GE 7FA.03	1,434 lb CO_2/MW-hr
GE 7FA.04	1,415 lb CO_2/MW-hr
GE 7FA.05	1,388 lb CO_2/MW-hr
SGT6-5000F(5)ee	1,406 lb CO_2/MW-hr

HCGF's GHG BACT limit of between 1,388 and 1,434 lb CO_2/MW-hr, depending on CT option selected, is consistent with the BACT limits achieved in the recent similar projects noted in the RBLC search above. These limits are only achievable with the use of a modern natural-gas fired, thermally efficient simple cycle CT combined with good combustion and maintenance practices to maintain optimum efficiency. The proposed CTs are consistent with BACT and the specific goals of this project. The proposed CTs, operational techniques, and emission limits represent BACT.

Maintenance, Startup, Shutdown, and Reduced Load Operations
BACT will be achieved by minimizing the duration of startup and shutdown events, engaging the pollution control equipment as soon as practicable (based on vendor recommendations and guarantees), and meeting the emissions limitations of Special Condition No. 10 of the permit. The duration of each startup and shutdown on natural gas is limited to 30 minutes and 40 minutes on ULSD fuel oil.

B. Emergency Engines
Annual non-emergency operation of the engines is limited to 100 hours per year. The emergency engines will use clean fuels by the exclusive use of ULSD. Good combustion practices will include complying with manufacturers recommended operation and maintenance procedures. Compliance with NSPS Subpart IIII will demonstrate efficient engine design. These design and operational requirements are considered BACT for diesel engines with limited non-emergency operational hours.

C. Fugitive Natural Gas Component Leaks
Leak detection and repair programs are potentially applicable and available although natural gas piping fugitives at about 8 tpy CO_2/200 tpy CO_2e emissions are 0.01% of the project total. Hand-held analyzers, remote sensing and audio, visual, and olfactory (AVO) detection methods are among the possible control methods. Based on the very small amount of emissions, the least costly of these methods, AVO programs, have been required in recent GHG permits. Piping and valves in natural gas service within the operating area must be checked weekly for leaks using AVO sensing for natural gas leaks. If the site is not manned for a given week, an AVO check shall be performed the next week plant personnel are on-site. The AVO program represents BACT for fugitive natural gas component leaks.

D. Fugitive SF_6 Emissions from Circuit Breakers
The circuit breakers will be designed to meet the latest ANSI standards for high voltage circuit breakers. The circuit breakers will have low pressure alarms and lockouts, which will function as early leak detectors. State of the art, enclosed-pressure SF_6 circuit breakers with leak detection satisfy GHG BACT requirements for this source.

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

A. De Minimis Analysis
A De Minimis modeling analysis was conducted initially to determine if a full impacts analysis would be required. The De Minimis analysis indicates that the project impacts for the 1-hr NO_2 NAAQS and the 24-hr $PM_{2.5}$ for both the NAAQS and PSD increment exceed de minimis concentrations and require full impacts modeling analysis. The project impacts below de minimis concentrations for which no further NAAQS modeling is required include: SO_2 (1-hr, 24-hr, and annual), PM_{10} (24-hr), $PM_{2.5}$ (24-hr and annual), NO_2 (annual). Similarly, impacts are below de minimis concentrations, and no further analysis is required for the following PSD increments: PM_{10} (24-hr and annual), $PM_{2.5}$ (annual), and SO_2 (3-hr).

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 that deminimis levels of 4% of the 1-hr NO_2 and SO_2 NAAQS are reasonable to use, at least in the current interim period before additional rulemaking.

The applicant provided an evaluation of ambient $PM_{2.5}$ monitoring data, consistent with EPA guidance for $PM_{2.5}$[4], for using the $PM_{2.5}$ De Minimis levels in the NAAQS analysis. If monitoring data shows that the difference between the $PM_{2.5}$ NAAQS and the monitored $PM_{2.5}$ background concentrations in the area is greater than the $PM_{2.5}$ De Minimis level, then the proposed project with predicted impacts below the De Minimis level would not cause or contribute to a violation of the $PM_{2.5}$ NAAQS and does not require a full impacts analysis. See the discussion below in the air quality monitoring section (VII.B.) for additional information on the evaluation of ambient $PM_{2.5}$ monitoring data.

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

Table VII-1. Modeling Results for PSD De Minimis Analysis in micrograms per cubic meter, µg/m³

Pollutant	Averaging Time (Standard)*	GLCmax (µg/m³)	De Minimis (µg/m³)
SO_2	1-hr (N)	7.1	7.8
	3-hr (I)	7.2	25
	24-hr (N,I)	3.8	5
	Annual (N,I)	0.017	1
PM_{10}	24-hr (N,I)	3.5	5
	Annual (I)	0.082	1
$PM_{2.5}$	24-hr (N)	1.8	1.2
	Annual (N)	0.078	0.3
	24-hr (I)	3.5	1.2
	Annual (I)	0.082	0.3

[2] www.epa.gov/region07/air/nsr/nsrmemos/appwso2.pdf
[3] www.epa.gov/nsr/documents/20100629no2guidance.pdf
[4] www.epa.gov/ttn/scram/guidance/guide/Guidance_for_PM25_Permit_Modeling.pdf

Pollutant	Averaging Time (Standard)*	GLCmax ($\mu g/m^3$)	De Minimis ($\mu g/m^3$)
NO_2	1-hr (N)	43.6	7.5
	Annual (N,I)	0.507	1
CO	1-hr (N)	408	2,000
	8-hr (N)	494	500

*Standards are: N – NAAQS; I – Increment.

The 1-hr SO_2, 24-hr and annual $PM_{2.5}$ (NAAQS), and 1-hr NO_2 GLCmax are based on the highest five-year averages of the maximum predicted concentrations determined for each receptor.

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

The applicant did not report the overall GLCmax for 1-hr NO_2 in the modeling report. The ADMT supplemented the value in Table 1 based on the modeling output files.

The applicant relied on guidance from EPA on evaluating intermittent emissions for the 1-hr SO_2 and 1-hr NO_2 NAAQS analyses. See section 4 of the modeling audit memo for additional details.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that 24-hr SO_2, 24-hr PM_{10}, annual NO_2, and 8-hr CO impacts are below their respective monitoring significance levels.

Table VII-2. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Significance ($\mu g/m^3$)
SO_2	24-hr	3.8	13
PM_{10}	24-hr	3.5	10
NO_2	Annual	0.507	14
CO	8-hr	494	575

The GLCmax for all pollutants and averaging times 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 483491051 located at Corsicana Airport, Corsicana, Navarro

County. The applicant used a three-year average (2012-2014) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value (21.4 μg/m³). The applicant used a three-year average (2012-2014) of the annual mean concentrations for the annual value (8.9 μg/m³). The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative analysis of source emissions located within ten kilometers (km) of the project site and monitor location.

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that the 24-hr $PM_{2.5}$ and 1-hr NO_2 impacts exceed the applicable de minimis concentrations 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 VII-3. 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	3.9	21.4	25.3	35
NO_2	1-hr	99.4	76	175.4	188

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 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.

Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 483491051 located at Corsicana Airport, Corsicana, Navarro County. The applicant used a three-year average (2012-2014) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative analysis of source emissions located within ten kilometers of the project site and monitor location.

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 483491051 located at Corsicana Airport, Corsicana, Navarro County. The three-year average (2012-2014) of the 98th percentile of the annual distribution of the daily maximum 1-hr concentrations was used for the 1-hr value. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative analysis of source emissions located within ten kilometers of the project site and monitor location.

The applicant provided an evaluation of secondary $PM_{2.5}$ impacts that considers modeling results of the directly emitted $PM_{2.5}$ emissions, ambient background monitoring data representative for the project site, and proposed allowable emission rates of SO_2 and NO_x:

- Adding the modeling results from the directly emitted $PM_{2.5}$ emissions to representative background concentrations gives total concentrations below the NAAQS.

- The proposed emissions of SO_2 and NO_x are greater than the SO_2 and NO_x significant emission rates of 40 tpy. Secondary $PM_{2.5}$ formation occurs as a result of chemical transformations that occur in the atmosphere gradually over time and only a portion of the SO_2 and NO_x emissions would be affected. Furthermore, secondary $PM_{2.5}$ formation from SO_2 and NO_x are unlikely to overlap in space or time with nearby maximum primary $PM_{2.5}$ impacts associated with the project sources.

- The applicant considered the potential contribution of secondary $PM_{2.5}$ from the proposed precursor emissions for the project with a comparison of the project emissions to existing regional $PM_{2.5}$ precursor emissions based on 2011 National Emissions Inventory database (NEI) and determined that the precursor emissions from the project (659.46 tpy) are a small percentage of the precursor emissions from the region (5,807 tons).

- In addition, only a portion of the proposed SO_2 and NO_x emissions would be expected to convert to secondary $PM_{2.5}$ in the form of ammonium sulfate and ammonium nitrate. The applicant reviewed $PM_{2.5}$ speciated monitoring data from a representative monitor (EPA AIRS monitor 481390016) to provide an estimate for the potential secondary $PM_{2.5}$ sulfate and nitrate concentrations in the air shed. Based on the speciated monitoring data and the comparison of precursor emissions from the project in relation to the air shed, particulate sulfate and nitrate formation are expected to be a small fraction of existing secondary $PM_{2.5}$.

Based on the analysis presented by the applicant, secondary formation of $PM_{2.5}$ would not be expected to cause or contribute to a NAAQS or increment violation.

Table VII-4. PSD Ambient Air Quality Analysis for Ozone

Pollutant	Monitor	Averaging Time	Background (ppb)	Standard (ppb)
O_3	483491051	8-hr	66	75

Background concentrations for O_3 were obtained from the EPA AIRS monitor 483491051 located at Corsicana Airport, Corsicana, Navarro County. A three-year average (2012-2014) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative analysis of source emissions located within ten km of the project site and monitor location.

EPA Region 6 has previously recommended a conservative analysis based on NO_2 modeling to estimate the potential impacts on ozone levels. Considering that it takes time for the NO_2 emissions to react to generate ozone, an evaluation of maximum estimated NO_2 concentrations at a distance of 10-11 km downwind from the proposed source could be used to estimate the potential ozone impacts. EPA Region 6 has recommended, based on similar electric generating unit plumes, that this type of emission source could have an average ozone yield of up to 2-3 ozone molecules per NO_2 molecule. The applicant used AERMOD to calculate a maximum 8-hr NO_x concentration of 2.39 parts per billion (ppb) at a distance of ten km. Assuming 90% conversion of NO_x to NO_2 and an ozone yield of three ozone molecules per molecule of NO_x, the 8-hr maximum predicted increase of ozone would be 7.19 ppb. Adding 7.19 ppb to the 8-hr ozone background will result in a total 8-hr ozone concentration that is less than the 8-hr ozone NAAQS.

D. Increment Analysis

A De Minimis modeling analysis was conducted for $PM_{2.5}$ increment; however, sufficient justification was not provided to use the De Minimis levels to forego a full PSD increment analysis. Therefore, a full PSD increment analysis for 24-hr and annual $PM_{2.5}$ was provided.

The applicant limited the 24-hr $PM_{2.5}$ increment demonstration to significant receptors. To justify the use of the De Minimis levels for the full 24-hr $PM_{2.5}$ increment analysis, the applicant reviewed emissions inventory data to illustrate how much increment consumption and/or expansion has potentially occurred in the area since the $PM_{2.5}$ major source and minor source baseline dates. The applicant began by reviewing off-property inventory data to determine which facilities are increment affecting sources. There were 13 facilities that were new or had an increase in emissions after the applicable baseline dates. Of the 13 facilities, four were within 15 km of the project site and one was less than ten km. The sources from the site that was less than ten km from the project site had hourly emission rates of 0.1 lb/hr or less. Furthermore, the significant receptors from the preliminary analysis extended to a maximum distance of 1.5 km from the project site. Due to the minimal amount of $PM_{2.5}$ increment consuming sources, coupled with the small radius-of-impact from the project site, the methodology described offers a reasonable approach for using the De Minimis levels to limit the demonstration to significant receptors for the full 24-hr $PM_{2.5}$ increment consumption analyses.

The applicant used the same significant receptors from the full 24-hr $PM_{2.5}$ increment demonstration to evaluate the annual $PM_{2.5}$ increment without providing justification. Due to this approach, the GLCmax from the annual $PM_{2.5}$ De Minimis analysis was not included in the full annual increment demonstration. However, based on a comparison of the receptors from the annual De Minimis modeling analysis that were included in the annual full increment analysis, the off-property sources do not contribute significantly. Therefore, the inclusion of all receptors would not change the overall conclusions.

Table VII-5. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (µg/m³)	Increment (µg/m³)
$PM_{2.5}$	24-hr	2.24	9
$PM_{2.5}$	Annual	0.071	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.

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 primary and secondary NAAQS. The applicant meets the Class II visibility analysis requirement by complying with the opacity requirements of 30 TAC 111. The Additional Impacts Analysis is reasonable and possible adverse impacts from this project are not expected.

The ADMT evaluated predicted concentrations from the proposed site to determine if emissions could adversely affect a Class I area. The nearest

Class I area, Wichita Mountains, is located approximately 310 km from the proposed site to the northwest.

The H_2SO_4 24-hr maximum predicted concentration of 0.24 µg/m³ occurred approximately 414 meters from the property line towards the south. 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 Wichita Mountains Class I area is 0.007 µg/m³. The Wichita Mountains Class I area is an additional 260 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 Wichita Mountains 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 12 km from the proposed sources in the direction of Wichita Mountains Class I area. The Wichita Mountains Class I area is an additional 298 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 Wichita Mountains Class I area.

F. State Property-Line Analysis

The applicant conducted modeling for the 30 TAC 112 property line standards. Property line standards, also called upwind-downwind standards, are a measure of the contribution of only the sources within the property line to air pollution levels.

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

Pollutant	Averaging Time	GLCmax (µg/m³)	Standard (µg/m³)
SO_2	1-hr	10	1,021
H_2SO_4	1-hr	1.5	50
H_2SO_4	24-hr	0.24	15

The predicted SO_2 and H_2SO_4 concentrations are less than the TCEQ's property-line standards.

G. Greenhouse Gases

The U.S. EPA has stated that unlike the criteria pollutants for which EPA has historically required PSD permits, there are no NAAQS or allowable deterioration increments for GHG emissions. The global climate change-inducing effects of GHG emissions according to the EPA's

"Endangerment and Cause or Contribute Finding" are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluation of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit review. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible (EPA's PSD and Title V Permitting Guidance for GHGs at 48). Thus, EPA has concluded in other GHG PSD permitting actions that it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit.

The TCEQ has determined that a GHG air quality analysis would provide no meaningful data for GHGs from this source and has not required the applicant to perform one. As demonstrated by the permit applicant's air quality analysis, the ADMT's review and description of that modeling in this section VII. of the preliminary determination summary, and as stated in the preamble to TCEQ's adoption of the GHG PSD program, the impacts review for individual air contaminants continues to be addressed in the state's traditional minor and major NSR permits program, in accordance with 30 TAC Chapter 116.

VIII. Conclusion

Brazos has demonstrated that this project meets all applicable rules, regulations and requirements of the Texas and Federal Clean Air Acts. The proposed facilities and emission controls represent BACT. The modeling analysis indicates that the proposed project will not violate the NAAQS, cause an exceedance of any of the PSD increments, or have any adverse impacts on soils, vegetation, or PSD Class I areas. In addition, the modeling predicted no impacts above ESLs at any receptor for the non-criteria contaminants evaluated.

The Executive Director of the TCEQ proposes a preliminary determination of issuance of this permit for Brazos to construct the HCGF as proposed.