TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

November 5, 2020

MR CRAIG ECKBERG
SR DIRECTOR ENVRIONMENTAL SERVICES
NRG CEDAR BAYOU 5 LLC
910 LOUISIANA ST
HOUSTON TX 77002-4916

Re: Permit, Prevention of Significant Deterioration Permit, and Greenhouse Gas Prevention of Significant Deterioration Permit
Permit Numbers: 160538, PSDTX1582, and GHGPSDTX204
NRG CEDAR BAYOU 5 LLC
Electric Generating Unit 5
Baytown, Chambers County
Regulated Entity Number: RN100825371
Customer Reference Number: CN605766492

Dear Mr. Eckberg:

The Texas Commission on Environmental Quality (TCEQ) has made a preliminary decision on the above-referenced application. In accordance with Title 30 Texas Administrative Code § 39.419(b), you are now required to publish Notice of Application and Preliminary Decision. You must provide a copy of this preliminary decision letter with the draft permit at the public place referenced in the public notice.

If you have any questions, please call Ms. Ruth Alvirez at (512) 239-5220, or write to the TCEQ, Office of Air, Air Permits Division, MC-163, P.O. Box 13087, Austin, Texas 78711-3087.

Sincerely,

Samuel Short, Director
Air Permits Division
Office of Air

Enclosure

cc: Air Section Manager, Region 12 - Houston

Project Number: 313800

Preliminary Determination Summary
NRG Texas Power LLC
Permit Numbers 160538, PSDTX1582, and GHGPSDTX204

I. Applicant

NRG Texas Power LLC
1201 Fannin St Suite 8802
Houston, Texas 77002-6929

II. Project Location

Cedar Bayou Electric Generating Station
7705 West Bay Road
Chambers County
Baytown, Texas 77523

III. Project Description

NRG Texas Power, LLC (NRG) owns and operates the Cedar Bayou Electric Generating Station (CBY Electric Generating Station). NRG Texas is proposing to construct an additional electric power generation block at the Cedar Bayou Station Power Project which will generate electric power for sale on the wholesale electric market.

The Cedar Bayou Power Project will include one power block which will be either a simple cycle or combined cycle option. Ancillary equipment includes an auxiliary boiler, a dewpoint gas heater, a cooling tower, a steam generator, and a diesel-fired generator.

Combustion Turbine and Heat Recovery Steam Generator

The station will consist of one natural gas fired combustion turbine (CTG) in either a simple or combined cycle configuration. The combined cycle option will be equipped with a supplementary fired [duct burners (DB)] heat recovery steam generator (HRSG). The CTGs and DBs are fueled with pipeline quality natural gas.

The gas turbine will be a Mitsubishi, model MHI501JAC. The net electrical generation of the simple cycle configuration will be a nominal 415 MW and the net electrical generation of the combined cycle configuration will be a nominal 689 MW. The facilities will fire only natural gas.

Selective Catalytic Reduction and Ammonia Handling Systems

In either option, the CTG will be will use an aqueous ammonia-based selective catalytic reduction (SCR) system to control NO_x emissions. The system will be comprised of aqueous ammonia storage and handling equipment, an ammonia vaporizer, an ammonia injection grid, and catalyst bed modules. The ammonia injection grid and the SCR catalyst beds will be installed in the HRSG housings at locations where exhaust temperatures will promote the NO_x reduction reactions. The aqueous ammonia will be delivered by tanker truck, which will use vapor balance to capture emissions during filling of the storage tanks. In addition, the aqueous ammonia will be stored in pressurized tanks equipped with pressure relief valves to prevent emissions. However, piping and fittings associated with the tanks and the transfer of ammonia throughout the system will be sources of fugitive emissions.

Dewpoint Heater

The dewpoint heater will have a maximum heat input of 9.7 MMBtu/hr and limited to firing natural gas. The dewpoint heater will be utilized to preheat the natural gas. Maintaining the gas above its dewpoint temperature prevents it from condensing into a liquid due to changes in pressure or temperature.

Auxiliary Boiler

The natural gas-fired auxiliary boiler will have a maximum heat input of 89.1 MMBtu/hr. The boiler will provide turbine fast start steam requirements.

Diesel Generator

A diesel-fired will be installed to produce electricity for the electric power grid and to serve as backup power during emergencies. A diesel storage tank is included with the generator housing.

Cooling Tower

A condenser/cooling tower arrangement will be utilized to cool steam exhausted from each turbine train. Each condenser will be a surface contact heat exchanger and each cooling tower will be multi-cell motor driven, mechanical draft, counter-flow tower with film fill. The tower will have a 90,000 gallon per minute circulation rate.

Natural Gas Piping Fugitives

Natural gas will be delivered to the site via pipeline and then metered and piped to the combustion turbine. The piping and fittings associated with the pipeline will be sources of fugitive emissions.

Maintenance, Startup and Shutdown (MSS)

Planned MSS emissions are being authorized in this project. This will result in separate emission rates for MSS in the table entitled “Emission Sources - Maximum Allowable Emission Rates,” (MAERT). The startup and shutdown will have separate short term (hourly) limits and the annual emissions are not expected to exceed the normal operations annual emissions and are included in the annual emissions limits in the MAERT. The durations of startups and shutdowns are included in the Special Conditions of the permit.

Maintenance Activities are identified in Attachment A and are quantified on the MAERT as Emission Point Number (EPN): FUG-MSS.

IV. Emissions

Emission sources for the proposed project consists of one power blocks, lube oil vents, cooling tower, auxiliary boiler, diesel generator, and equipment fugitives.

V. Federal Applicability

The Cedar Bayou Project is located in Chambers County which is classified as serious nonattainment. The site is an existing major source with respect to the Prevention of Significant Deterioration (PSD) and Nonattainment (NA) New Source Review programs (NSR). The combined cycle option was used for the Federal Applicability review which represents the worst case scenario.

The new project will have the potential to emit emissions greater than the major modification significance level for the pollutants identified below. There were no actions in contemporaneous window.

The following charts illustrate the annual project emissions for each pollutant and whether this pollutant triggers PSD review. The worst-case emission increases from the two options were chosen for this demonstration. These totals include MSS emissions.

The Cedar Bayou Electric Generating Station has an existing Plantwide Applicability Limit (PAL) for NO_x. NRG Texas represented that NO_x emissions from this project along with existing sources at the site will not exceed the existing PAL; therefore, a PSD and NA review is not triggered. A review of Environmental Protection Agency's acid rain database confirms that actual NO_x emissions are substantially below the existing PAL and that NRG's proposed project would not be expected to exceed the existing PAL. A minor NSR review was performed for NO_2.

Table 1. PSD Major Modification Trigger

Pollutant	Project Increase (tpy)	PSD Netting Trigger (tpy)	Netting Required (Y/N)	Net Emission Change (tpy)	PSD Major Mod Trigger	PSD Review Triggered (Y/N)
CO	127.17	100	**Y**	127.17	100	**Y**
VOC	24.97	40	N	24.97	40	N
PM	202.92	25	**Y**	202.92	25	**Y**
PM_{10}	97.22	15	**Y**	97.22	15	**Y**
$PM_{2.5}$	96.89	10	**Y**	96.89	10	**Y**
SO_2	24.26	40	N	24.26	40	N
H_2SO_4	16.23	7	**Y**	16.23	7	**Y**

The VOC and SO_2 project increases were below the PSD major modification significance level; therefore, a PSD review is not required for these pollutants. A minor NSR review was performed for SO_2.

Table 2. NA Modification Trigger

Pollutant	Project Increase (tpy)	NA Netting Trigger (tpy)	Netting Required (Y/N)	Net Emission Change (tpy)	NA Major Mod Trigger (tpy)	NA Review Triggered (Y/N)
VOC	24.97	5	**Y**	24.97	25	N

VOC is below the NA major modification trigger; therefore, a NA review is not required.

Table 3. PSD Major Modification Trigger

Pollutant	Project Increase (tpy)	PSD Netting Trigger (tpy)	Netting Required (Y/N)	Net Emission Change (tpy)	PSD Major Mod Trigger	PSD Review Triggered (Y/N)
CO_2e	2,070,714	75,000	**Y**	2,070,714	75,000	**Y**

VI. Control Technology Review

BACT determinations are based upon an evaluations of information from the Environmental Protection Agency's (EPA's) RACT/BACT/LAER Clearinghouse (RBLC), TCEQ Current BACT Spreadsheet (June 2019), TCEQ Gas Turbine list (November 2019), on-going permitting in Texas and other states, and the TCEQ's continuing review of emissions control developments.

Combustion Turbines

NO_x Emissions – Combined Cycle

NO_x emissions from combustion turbines are generated through the oxidation of nitrogen in the high temperature combustion zones. Dry low NO_x combustors (DLNs) and SCR technology will be used to limit NO_x emissions to 2.0 ppmvd corrected to 15 percent oxygen (% O_2) on a rolling one-hour average. The proposed use of SCR and DLN combustors meets BACT requirements.

NO_x Emissions – Simple Cycle

DLN combustors and SCR technology will limit NO_x emissions to 2.5 ppmvd corrected to 15 % O_2 on a rolling one-hour average and shall have an operational limitation of 14,552,539 MMBtu/yr. The proposed control and an operational limitation represent BACT.

CO Emissions – Combined Cycle

CO emissions are the result of incomplete combustion of the carbon in a fuel. Good combustion practices, DLNs, and an oxidation catalyst will limit CO to a level of 4.0 ppmvd (3-hour average) corrected to 15% O_2. A search of the RBLC and the TCEQ Gas Turbine List for facilities permitted since January 2014 to 2019 show that the CO emission limits ranged from 0.9 to 25 ppmvd corrected to 15% O_2. Good combustion practices, DLNs, and/or the use of an oxidation catalyst were listed as control for CO. The proposed controls and emission limits are consistent with the top levels of control for natural gas-fired combined cycle turbines; therefore, BACT is satisfied.

CO Emissions – Simple Cycle

CO emissions are the result of incomplete combustion of the carbon in a fuel. Good combustion practices, DLNs, and an oxidation catalyst will limit CO to a level of 3.5. ppmvd (3-hour average) corrected to 15% O_2. A search of the RBLC and the TCEQ Gas Turbine List for facilities permitted since January 2014 to 2019 show that the CO emission limits ranged from 0.9 to 29 ppmvd corrected to 15% O_2. Good combustion practices, DLNs, and/or the use of an oxidation catalyst were listed as control for CO. The proposed controls and emission limits are consistent with the top levels of control for natural gas-fired combined cycle turbines; therefore, BACT is satisfied.

VOC Emissions – Combined Cycle

VOC emissions will result from the incomplete combustion of the natural gas. Good combustion practices, DLNs, and an oxidation catalyst will limit VOC emissions to 1.0 ppmvd (simple cycle) corrected to 15% O_2. A search of the RBLC and the TCEQ Gas Turbine List for facilities permitted since January 2014 to 2019 show that the VOC emission limits ranged from 0.7 to 2.4 ppmvd corrected to 15% O_2. Good combustion practices, DLNs, and/or the use of an oxidation catalyst were listed as control for VOC. The proposed controls and emission limits are consistent with the top levels of control for natural gas-fired combined cycle turbines; therefore, BACT is satisfied.

VOC Emissions – Simple Cycle

VOC emissions will result from the incomplete combustion of the natural gas. Good combustion practices, DLNs, and an oxidation catalyst will limit VOC emissions to 1.5 ppmvd (simple cycle) corrected to 15% O_2. A search of the RBLC and the TCEQ Gas Turbine List for facilities permitted since January 2014 to 2019 show that the VOC emission limits ranged from 0.7 to 2.0 ppmvd corrected to 15% O_2. Good combustion practices, DLNs, and/or the use of an oxidation catalyst were listed as control for VOC. The proposed controls and emission limits are consistent with the top levels of control for natural gas-fired combined cycle turbines; therefore, BACT is satisfied.

$PM/PM_{10}/PM_{2.5}$ Emissions – Combined/Simple Cycle

$PM/PM_{10}/PM_{2.5}$ is emitted from combustion processes as a result of the presence of ash and other inorganic constituents contained in the fuel, particulate matter in the inlet air, and incomplete combustion of the organic constituents in the fuel. Because the combustion turbines will only fire natural gas, $PM/PM_{10}/PM_{2.5}$ emissions will primarily be limited to the incomplete combustion and are anticipated to be relatively low. A search of the RBLC and TCEQ Gas Turbine List shows that no add-on controls are required for natural gas-fired combustion turbines to control $PM/PM_{10}/PM_{2.5}$. Therefore, the use of pipeline-quality natural gas and the application of good combustion controls is BACT for $PM/PM_{10}/PM_{2.5}$.

Sulfur Compound Emissions – Combined/Simple Cycle

Emissions of SO_2 will occur as a result of oxidation of sulfur in the natural gas-fired in the combustion turbines, with the majority of the sulfur converted to SO_2. A portion of the SO_2 will be further converted to H_2SO_4, with a conversion contribution due to the action of the SCR. The formation of SO_2 and H_2SO_4 will be minimized by using pipeline-quality natural gas with a sulfur content not exceeding 1.0 grains sulfur per 100 standard cubic feet on an hourly basis and 0.5 gr/100dscf on an annual basis. A search of the RBLC and TCEQ Gas Turbine List for facilities permitted since January 2014 did not show any post-combustion SO_2 control technologies. Therefore, the use of sweet natural gas with the sulfur content listed above is BACT for SO_2 and H_2SO_4.

Ammonia (NH_3) Emissions – Combined/Simple Cycle

NRG, for either operating option, will operate the SCR systems in such a manner that NH_3 slip (i.e., the emission of unreacted NH_3 to the atmosphere) is minimized while ensuring that the NO_x emissions limits are met. Careful control of the NH_3 injection system and operating parameters will be maintained to control NH_3 slip in the exhaust stream to levels not exceeding 10.0 ppmvd corrected to 15% O_2. This level of emissions control meets the requirements of BACT for NH_3 slip as specified in the TCEQ's BACT Requirements table for combustion turbines.

GHG – Combined Cycle

The most efficient means to reduce the amount of CO_2 generated by a fuel burning power plant is to generate as much electric power per unit of fuel combusted This result is obtained by using the most efficient generating technologies available, so that as much of the energy content of the fuel as possible goes into generating power. Combined cycle configurations are the most efficient way to generate electricity. NRG is proposing 827 lb CO_2/MWh. A search of the RBLC and the TCEQ Gas Turbine List for facilities permitted since January 2014 to 2019 show that the CO_2 emission limits ranged from 775 – 1,800 lb/MWh. The proposed emission limit represents BACT.

GHG – Simple Cycle

A simple cycle turbine has a lower energy efficiency than a combined cycle turbine. Simple cycle units serve a different purpose that the combined cycle turbine and their ability to quickly ramp up and down make them ideal for “peaking” quick ramping for use during periods with the highest electricity demand. Simple cycle turbines are not intended to be used as a base load unit with full time operation. NRG is proposing a CO_2 limit of 1,194 lb/MWh. NRG is proposing 876 lb CO_2/MWh and an operational limitation of 14,552,539 MMBtu/yr. A search of the RBLC and the TCEQ Gas Turbine List for facilities permitted since January 2014 to 2019 show that the CO_2 emission limits ranged from 1,293 to 1,461 lb/MWh. The proposed emission limit and operational limitation represents BACT.

Startup and Shutdown Emissions

Operation of the combustion turbines will result in emissions from startup and shutdown. The combustion turbines will be started up and shut down in a manner that minimizes the emissions during these events. BACT will be achieved by minimizing the duration of the startup and shutdown events (consistent with market demands), engaging the pollution control equipment as soon as practicable (based on vendor recommendations and guarantees), and meeting the emissions limitations on the MAERT. The duration of each startup and shutdown is limited to 120 minutes.

Other Emission Sources

Auxiliary Boiler – The use of natural gas, an operation limitation of 178,200 MMBtu/yr on a rolling 12-month average, a NO_x limitation of 0.036 pounds per MMBtu (lb/MMBtu), CO limitation of 0.037 lb/MMBtu, periodic maintenance, and the installation of an automated air/fuel controller represents BACT.

Dewpoint Heater – Good combustion practices and the firing of natural gas are considered BACT for heater of this size.

Diesel-Fired Generator - BACT will be achieved through firing diesel fuel containing no more than 15 parts per million sulfur by weight, proper operation and maintenance, and limiting annual operation to 500 per year.

Diesel Storage Tanks - A fixed roof tank (< 25 thousand gallons [Mgal]) will store the diesel fuel for the generator. Because of the very low vapor pressure of this fuel and the resulting minimal emissions from the tanks, BACT is satisfied with the use of good management practices (such as white painted or unpainted aluminum and submerged filling).

Cooling Towers **-** The drift eliminators limit drift to 0.0005%, which is consistent with other recent PM/PM_{10}/$PM_{2.5}$ BACT determinations within the RBLC and TCEQ Current BACT Spreadsheet (June 2019).

Fugitives - Include VOC which originate from the natural gas fuel lines and NH3 from the NH3 delivery system of the SCR. The uncontrolled VOC emissions less than 10 tons per year and due to the negligible amount of GHG emissions from process fugitives, the only available control, implementation of a Leak Detection and Repair Program (LDAR), is not cost effective and would result in no significant reduction in overall project GHG emissions. Periodic audio/visual/olfactory inspections will be performed for NH3 and natural gas. Any leaks will be repaired when detected. Therefore, BACT is satisfied.

SF_6 Electrical Equipment – The use of circuit breakers with totally enclosed insulation systems equipped with a low-pressure alarm/lockout is BACT.

VII. Air Quality Analysis

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

A. De Minimis Analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results for 24-hr $PM_{2.5}$ (NAAQS and Increment) exceed the respective de minimis concentrations and require a full impacts analysis. The De Minimis analysis modeling results for 24-hr and annual PM_{10}, 1-hr and 8-hr CO, and annual $PM_{2.5}$ (NAAQS and Increment) indicate that the project is below the respective de minimis concentrations and no further analysis is required.

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

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

Table 4. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter (μg/m³)

Pollutant	Averaging Time	GLCmax (μg/m³)	De Minimis (μg/m³)
PM_{10}	24-hr	4	5
PM_{10}	Annual	0.2	1
$PM_{2.5}$ (NAAQS)	24-hr	3.3	1.2
$PM_{2.5}$ (NAAQS)	Annual	0.11	0.2

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

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	De Minimis ($\mu g/m^3$)
$PM_{2.5}$ (Increment)	24-hr	4.1	1.2
$PM_{2.5}$ (Increment)	Annual	0.13	0.2
CO	1-hr	102	2000
CO	8-hr	7	500

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

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

To evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's Guideline on Air Quality Models (GAQM). Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as Modeled Emission Rates for Precursors (MERPs). The basic idea behind the MERPs is to use technically credible air quality modeling to relate precursor emissions and peak secondary pollutants impacts from a source. Using data associated with the 500 tpy Harris County source, the applicant estimated 24-hr and annual secondary $PM_{2.5}$ concentrations of 0.03 $\mu g/m^3$ and 0.001 $\mu g/m^3$, respectively. When these estimates are added to the GLCmax listed in the table above, the results for annual $PM_{2.5}$ (NAAQS and Increment) are less than the De Minimis levels. Since the combined direct and secondary 24-hr $PM_{2.5}$ impacts (NAAQS and Increment) are above the De minimis levels, a full impacts analysis is required.

The project site is located in the Houston-Galveston-Brazoria ozone nonattainment area. Therefore, an ambient ozone impacts analysis is not required.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that 24-hr PM_{10} and 8-hr CO are below their respective monitoring significance level.

Table 5. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Significance ($\mu g/m^3$)
PM_{10}	24-hr	4	10
CO	8-hr	7	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.

A background concentration for $PM_{2.5}$ was obtained from the EPA AIRS monitor 482010058 located at 7210 ½ Bayway Dr., Baytown, Harris County. The three-year average (2017-2019) of the 98th percentile of the annual distribution of the 24-hr concentrations was used for the 24-hr value (22 µg/m^3). The three-year average of the annual average concentrations from 2017-2019 was used for the annual value (9.4 µg/m^3). The use of this monitor is reasonable based on a comparison of land use and a quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site. The 24-hr background concentration was used in the NAAQS analysis.

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 24-hr $PM_{2.5}$ exceeds the respective de minimis concentration and requires a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 6. Total Concentrations for PSD NAAQS (Concentrations > De Minimis

Pollutant	Averaging Time	GLCmax (µg/m^3)	Background (µg/m^3)	Total Conc. = [Background + GLCmax] (µg/m^3)	Standard (µg/m^3)
$PM_{2.5}$	24-hr	11	22	33	35

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.

As stated above, to evaluate secondary $PM_{2.5}$ impacts, the applicant provided an analysis based on a Tier 1 demonstration approach consistent with the EPA's GAQM. Specifically, the applicant used a Tier 1 demonstration tool developed by the EPA referred to as MERPs. Using data associated with the 500 tpy Harris County source, the applicant estimated a 24-hr secondary $PM_{2.5}$ concentration of 0.03 µg/m^3. When this estimate is added to the GLCmax listed in Table 3 above, the result is less than the NAAQS

D. Increment Analysis

The De Minimis analysis modeling results indicate that 24-hr $PM_{2.5}$ exceeds the de minimis concentration and requires a PSD increment analysis.

Table 7. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax (µg/m^3)	Increment (µg/m^3)
$PM_{2.5}$	24-hr	7.4	9

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

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

E. Additional Impacts Analysis

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

The ADMT evaluated predicted concentrations from the proposed project to determine if emissions could adversely affect a Class I area. The nearest Class I area, Caney Creek Wilderness, is located approximately 519 kilometers (km) from the proposed site.

The H_2SO_4 24-hr maximum predicted concentration of 0.8 µg/m^3 occurred approximately 401 meters from the fence line towards the northwest. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 30km from the proposed sources, in the direction of the Caney Creek Wilderness Class I area is 0.03 µg/m^3. The Caney Creek Wilderness Class I area is an additional 489 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 Caney Creek Wilderness Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, NO_2, and SO_2 for all averaging times, are all less than de minimis levels at a distance of 1 km from the proposed sources in the direction the Caney Creek Wilderness Class I area. The Caney Creek Wilderness Class I area is an additional 518 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 Caney Creek Wilderness Class I area.

F. Minor Source NSR and Air Toxics Review

Table 8. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax (µg/m^3)	Standard (µg/m^3)
SO_2	1-hr	99	1021
H_2SO_4	1-hr	0.9	50
H_2SO_4	24-hr	0.8	15

Table 9. Modeling Results for Minor NSR De Minimis

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	De Minimis ($\mu g/m^3$)
SO_2	1-hr	1.4	7.8
SO_2	3-hr	1.5	25
NO_2	1-hr	7.4	7.5
NO_2	Annual	0.2	1

The 1-hr SO_2 GLCmax is based on the highest five-year average of the maximum predicted concentrations determined for each receptor. The 3-hr SO_2 GLCmax is the maximum predicted concentration associated with five years of meteorological data.

The 1-hr NO_2 GLCmax is based on the highest five-year average of the maximum predicted concentrations determined for each receptor multiplied by a NO_x emissions ratio. The annual NO_2 GLCmax is based on the maximum predicted concentration associated with five years of meteorological data multiplied by a NO_x emissions ratio. To account for changes to the aux boiler's NO_2 rates that were not included in the modeling, the applicant calculated a ratio of all increases included in the modeling and all increases plus the increases associated with the aux boiler for both the 1-hr and annual averaging times. The modeled concentrations were multiplied by their respective ratios to give the results in Table 6 above. This approach is reasonable.

The primary NAAQS for 24-hr and annual SO_2 have been revoked for Chambers County and are not reported above.

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

Table 10. Minor NSR Production Project-Related Modeling Results for Health Effects

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	10% ESL ($\mu g/m^3$)
Ammonia 7664-41-7	1-hr	15	17

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

VIII. Conclusion

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

The Executive Director of the TCEQ proposes a preliminary determination of issuance of this permit for NRG to construct the electric power generating facilities and the associated support facilities, as proposed.

Special Conditions

Permit Numbers 160538, PSDTX1582, and GHGPSDTX204

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.

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

Federal Applicability

3. These facilities shall comply with applicable requirements of the EPA regulations on Standards of Performance for New Stationary Sources, Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):

   A. Subpart A: General Provisions.

   B. Subpart Dc: Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

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

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

   E. Subpart TTTT: Standards of Performance for Greenhouse Gas (GHG) Emission for Electric Generating Units

4. These facilities shall comply with applicable requirements of the EPA regulations on National Standards for Hazardous for Source Categories, Title 40 Code of Federal Regulations Part 63 (40 CFR Part 63):

   A. Subpart A: General Provisions.

   B. Subpart YYYY: National Emission Standards for HAPs for Stationary Combustion Turbines

   C. Subpart ZZZZ: National Emission Standards for HAPs for Stationary Reciprocating Internal Combustion Engines (RICE)

   D. Subpart DDDDD: National Emission Standards for HAPs for Major Sources: Industry, Commercial, and Institutional Boilers and Process Heaters

5. This permit authorizes a Mitsubishi (501JAC) natural gas fired combustion turbine (CTG) to be constructed in either a simple or a combined cycle configuration [Emission Point Number (EPN): CBY51]:

   A. Simple Cycle – the CTG is rated at nominal capability of 415 megawatts (MW).

   B. Combined Cycle – the CTG is rated at nominal capability of 689 megawatts (MW). The CTG will be equipped with a heat recovery steam generator (HRSG) and associated duct burners (DBs) with a maximum heat input of 784 million British thermal units per hour (MMBtu/hr).

Simple Cycle - Emissions Standards and Operating Specifications

6. The turbine (EPN: CBY51) shall not exceed the following emission limits expressed in parts per million by volume dry (ppmvd) at 15% oxygen (O_2) subject to the following specifications:

   A. Non-GHG Criteria Pollutants

Pollutant	Concentration	Averaging time
NO_x	2.5	1-hr average
CO	3.5	Rolling 3-hr average
NH_3	10.0	Rolling 3-hr average

   B. A planned startup is defined as the period from first combustion of fuel to compliance with the NOx and CO emission limits for the CTG. A planned startup shall not exceed 120 minutes. Planned startups are excluded from the emission limits of this Special Condition.

   C. A planned shutdown is defined as the period from minimum emission-compliant load to flame out. A planned shutdown shall no exceed 60 minutes. Planned shutdowns are excluded from the emission limits of this Special Condition.

   D. Emissions from maintenance activities (Attachment A) are excluded.

   E. The CTG is limited to 14,552,539 MMBtu/yr on a rolling 12-month average.

Combined Cycle Emission Rates/Operating Specifications

7. The CTG (EPN: CBY51) shall not exceed the following emission limits expressed in parts per million by volume dry (ppmvd) at 15% oxygen (O_2) subject to the following specifications:

Pollutant	Concentration	Averaging Time
Nitrogen oxide	2.0	1-hr average
Carbon monoxide (CO)	4.0	Rolling 3-hr average
Ammonia (NH_3)	10.0	Rolling 3-hr average

   A. A planned startup is defined as the period from first combustion of fuel to compliance with the NOx and CO emission limits for the CTG. A planned startup shall not exceed 120 minutes. Planned startups are excluded from the emission limits of this Special Condition.

   B. A planned shutdown is defined as the period from minimum emission-compliant load to flame out. A planned shutdown shall no exceed 60 minutes. Planned shutdowns are excluded from the emission limits of this Special Condition.

C. Emissions from maintenance activities (Attachment A) are excluded.

D. Reduced load operation is defined as operational loads below 60% of full load and the emission concentrations are excluded. The emission from reduced load operation shall not exceed the normal hourly emission rates in the MAERT.

CTG GHG Emission Rates/Operating Specifications

8. The CTG during turbine load operations shall not exceed the following limits based on a 12-month rolling average.

Turbine Operations	Output Specific CO_2 Emission Rate (lb CO_2/MWh)
Simple Cycle	1,194
Combined Cycle	827

Emissions associated with the activities listed in Special Condition No. 6 and 7 shall not be included in determining compliance with the performance standards listed above and shall be minimized through the application of work practices. Emissions during all operating modes shall not exceed the carbon dioxide equivalent (CO_2e) mass emission rates identified in the MAERT.

Auxiliary Boiler – Emission Limitations and Operating Specifications

9. The auxiliary boiler (EPN: AUX-BLR) shall not exceed the following emission limitations:

Pollutant	lb/MMBtu	Averaging time
NO_x	0.036	Rolling 3-hr average
CO	0.037	Rolling 3-hr average

A. Planned startups, shutdowns, and hot standby emissions as defined in this Special Condition are excluded from the limits listed above. The emissions from startup, shutdown, and hot standby shall not exceed the hourly emission rates in the MAERT.

B. A planned startup begins with first-firing fuel and ends when any of the steam from the boiler is supplied for heating or process purposes. Planned startups shall not exceed 1 hour.

C. A planned shutdown is defined as the period cessation of a boiler is initiated for any purpose and ends when the boiler no longer supplies thermal energy. Planned shutdowns shall not exceed 1 hour.

D. Hot standby is defined as pilot ignitors in service.

10. The auxiliary boiler shall not exceed 89.1 MMBtu/hr.

11. The auxiliary boiler shall not exceed 178,200 MMBtu/yr on a rolling 12-month average.

12. GHG Requirements

    A. The auxiliary boiler tips and convection tubes shall be inspected annually and cleaned as needed.

    B. An automated air/fuel control system shall be installed, operated, and maintained on the auxiliary boiler.

General Operating Specifications/Fuel Specifications

13. During normal operations, opacity of emissions from the CTG and auxiliary boiler stack authorized by this permit shall not exceed 5 percent averaged over a six-minute period. During periods of MSS operation of the turbines, the opacity shall not exceed 15 percent averaged over a six-minute period. The permit holder shall demonstrate compliance with this Special Condition in accordance with the following procedures:

    A. Visible emission observations shall be conducted and recorded at least once during each calendar quarter while the facilities are in operation, unless the emission unit is not operating for the entire calendar quarter.

    B. This determination shall be made by first observing for visible emissions while each facility is in operation. Observations shall be made at least 15 feet and no more than 0.25 miles from the emission point(s). Up to three emissions points may be read concurrently, provided that all three emissions points are within a 70-degree viewing sector or angle in front of the observer such that the proper sun position (at the observer's back) can be maintained for all three emission points. A certified opacity reader is not required for these visible emission observations.

    C. If visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60), Appendix A, Reference Method 9.

    D. If the opacity limitations of this Special Condition are exceeded, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation.

14. The CTG and diesel generator shall not be in startup operations at same time.

15. The dewpoint heater shall not exceed 9.7 MMBtu/hr.

16. The concentration of total dissolved solids (TDS) in the cooling water shall not exceed 60,000 ppm by weight.

17. The CTGs, duct burners, dewpoint heater, and auxiliary boiler shall be limited to the use of pipeline quality natural gas containing no more than 1.0 grains total sulfur per 100 dry standard cubic feet (gr/100 dscf) on an hourly basis and 0.5 gr/100 dscf on an annual basis.

18. The diesel generator is limited to the following

    A. Operation shall be limited to 500 hours of operation per year on a rolling 12-month average.

    B. Fuel shall be limited to diesel fuel containing no more than 15 ppm sulfur by weight.

Aqueous Ammonia (NH_3)

19. The permit holder shall maintain prevention and protection measures for the NH_3 storage system. The NH_3 storage tank area will be marked and protected so as to protect the NH_3 storage area from accidents that could cause a rupture.

20. The permit holder shall maintain the piping and valves in NH_3 service as follows:

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

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

        (1) Locate and isolate the leak, if necessary.

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

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

Initial Determination of Compliance

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

22. The holder of this permit shall perform stack sampling and other testing as required to establish the actual quantities of air contaminants being emitted into the atmosphere from EPNs: CBY51 and AUX-BLR to determine initial compliance with all emission limits established in this permit. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods to be determined during the pretest meeting.

    A. Air contaminants and diluents to be sampled and analyzed on the gas turbines include (but are not limited to) NO_x, O_2, CO, volatile organic compounds, sulfur dioxide (SO_2), particulate matter less than 10 microns in diameter, and NH_3.

    B. Air contaminants and diluents to be sampled and analyzed on the auxiliary boiler include (but are not limited to) NO_x, O_2, and CO.

    C. For the simple cycle mode operation each turbine shall be tested at or above 90 percent of maximum load operations. For the combined cycle operation each turbine shall be tested with duct burners at maximum firing rate while the turbine is operating as close to base load as possible.

    D. Fuel sampling using the methods and procedures of 40 Code of Federal Regulations, Subpart KKKK. If fuel sampling is used, compliance with New Source Performance Standards (NSPS) Subpart KKKK, SO_2 limits shall be based on 100 percent conversion of the sulfur in the fuel to SO_2. Any deviations from those procedures must be approved by the Executive Director of the TCEQ prior to sampling. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

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

F. The TCEQ Houston Regional Office shall be contacted as soon as testing is scheduled but not less than 45 days prior to sampling to schedule a pretest meeting. The notice shall include:

(1) Date for pretest meeting.

(2) Date sampling will occur.

(3) Name of firm conducting sampling.

(4) Type of sampling equipment to be used.

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

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

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

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

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

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

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

GHG Initial Demonstration of Compliance (CTGs)

23. After the first full calendar month of operation, the permit holder shall compare that month's gross heat rate and output specific CO_2 emission rate to the limits in this permit and the MAERT. Within 45 days after collecting the data, the permit holder shall submit a report to the region identifying whether the data causes any concerns regarding the permit holder's ability to comply with the applicable limitations.

Continuous Determination of Compliance

24. The holder of this permit shall install, calibrate, maintain, and operate a continuous emissions monitoring system (CEMS) to measure and record the concentrations of NO_x, CO, and diluents (O_2 or carbon dioxide) in the stack (EPN: CBY51).

A. Monitored NO_x and CO concentrations shall be corrected and reported in dimensional units corresponding to the emission rate and concentration limits established in this permit.

B. The CEMS data shall be used to demonstrate compliance with the emission limitations in the Special Conditions and the attached MAERT.

C. The NO_x/diluent CEMS shall be operated according to the methods and procedures as set out in 40 CFR § 60.4345 and the reporting of monitoring data shall be in accordance with 40 CFR § 60.4380(b).

D. The CO CEMS shall meet the appropriate quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Each CO monitor shall be quality-assured at least quarterly using Cylinder Gas Audits (CGA) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, Section 5.1.2, with the following exception: a relative accuracy test audit is not required once every four quarters if four successive quarterly CGA have been conducted for that four-quarter period. An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur at least two months apart.

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

25. The permit holder shall additionally install, calibrate, maintain, and operate continuous monitoring systems to monitor and record the average hourly natural gas consumption of the CTG and auxiliary boiler. The permit holder shall comply with the initial certification and quality assurances as specified in 40 CFR Part 75, Appendix D.

26. The NH_3 concentration in the stack (EPN: CBY51) shall be tested or calculated according to one of the methods listed below and shall be tested or calculated according to the frequency listed below. Testing for NH_3 slip is only required on days when the SCR unit is in operation.

A. The holder of this permit may install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NH_3. The NH_3 concentrations shall be corrected and reported in accordance with the limitations in this permit.

B. The permit holder may install and operate a second NO_x CEMS probe located between the duct burners and the SCR, upstream of the stack NO_x CEMS, which may be used in association with the SCR efficiency and NH_3 injection rate to estimate NH_3 slip. This condition shall not be construed to set a minimum NO_x reduction efficiency on the SCR unit. These results shall be recorded and used to determine compliance limits of this permit.

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

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

GHG Continuous Demonstration of Compliance (CTG Auxiliary Boiler, and Gas Heater)

27. Compliance with the GHG requirements of this permit shall be demonstrated by following the requirements of and using the applicable equations of 40 CFR, Part 98, Mandatory GHG Reporting. Global warming potentials are listed in footnote 3 of the MAERT.

Continuous Demonstration of Compliance (Natural Gas Fugitives)

28. 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) Use a leak collection or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

Continuous Demonstration of Compliance (Circuit Breakers)

29. The sulfur hexafluoride (SF_6)-enclosed circuit breakers shall be designed to meet the latest American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers. The circuit breakers must be guaranteed to achieve a SF_6 leak rate of 0.5% by weight or less annually. 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.

30. The permit holder shall equip the circuit breakers with a low pressure alarm and 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 a sulfur hexafluoride (SF_6) leak collections 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.

Maintenance

31. Compliance with the emissions limits for planned maintenance activities for EPN: CBY51 and FUG-MSS identified in Attachment A may be demonstrated as follows.

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

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

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

D. Emissions from CTG diagnostic load reduction activities identified in Attachment A shall be subject to the hourly MSS emission rates on the MAERT and shall not exceed 54 hours for all CTGs combined at the site.

Recordkeeping Requirements

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

   A. A copy of this permit.

   B. Permit application dated March 17, 2020, and subsequent representations submitted to the TCEQ.

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

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

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

   A. The CEMS data of NO_x, CO, and O_2 emissions from EPN: CBY51 to demonstrate compliance with the emission rates listed in this permit and attached MAERT.

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

   C. Records of dates and times for startups and shutdowns of the CTG and the auxiliary boiler.

   D. Records of the amount of natural gas fired on hourly and 12-month rolling average for the CTG, duct burners, gas heater, and auxiliary boiler.

   E. Records of visible emissions observations and opacity readings.

   F. Records of hours of operation and sulfur content of diesel fuel fired in the diesel generator.

   G. Records of AVO checks, maintenance performed to any piping and valves in NH_3 and natural gas service.

   H. Records of accidental releases, spills, or venting of NH_3 and the corrective action taken.

   I. Records of NH_3 monitoring.

   J. Records of monitored or calculated maintenance emissions.

   K. Records of all calculations to demonstrate compliance with 40 CFR Part 98.

L. Auxiliary boiler

(1) Records of annual inspections, cleaning, replacement/repair of the boiler tips and convection tubes.

(2) Records of calibrations, maintenance and repair/replacement of the air/fuel system.

M. Records of maintenance or leak repair performed on SF_6 containing circuit breakers.

N. Records of diagnostic load reduction activities and hours of operation for each CTG at the site.

Additional Provisions

34. The permit holder shall submit to the TCEQ Air Permits Division an alteration to change the permit to reflect the chosen operational mode, no later than 60 days before initial start-up of the CTG.

35. The performance specifications of Special Condition Nos. 6 through 9 and the MAERT do not apply during combustion shakedown. Shakedown is defined as the period beginning with initial startup and ending no later than initial demonstration of compliance, during which the permit holder conducts operational and contractual testing and tuning to ensure the safe, efficient and reliable operation of the plant. The shakedown period shall not exceed the time period for performance testing as specified in 40 CFR § 60.8.

Date:

Attachment A

Permit Numbers 160538, PSDTX1582, and GHGPSDTX204

Planned Maintenance Activities								
Activities	EPN	Emissions						
		NO_x	CO	VOC	PM	SO_2	NH_3
Combustion unit tuning[1]	CBY51 AUX-BLR	X	X	X	X	X	X
Diagnostic load reduction activities[2]	CBY51	X	X	X	X	X	
On-line turbine washing	CBY51	X	X	X	X	X	
Gaseous fuel venting[3]	FUG-MSS			X			
Miscellaneous PM filter maintenance[4]	FUG-MSS				X		
Boiler tube cleaning	FUG-MSS				X		
Storage vessel maintenance (<0.5 psia VP)	FUG-MSS			X			X
Management of sludge from pits, ponds, sumps, and water conveyances[5]	FUG-MSS			X			
Organic chemical usage	FUG-MSS			X			
Inspection, repair, replacement, adjusting, testing, and calibration of analytical equipment, process instruments including sight glasses, meters, gauges, CEMS, PEMS	FUG-MSS		X	X	X	X	
Small equipment and fugitive component repair/replacement in VOC and NH_3 service[6]	FUG-MSS			X			X

Date:

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

[2] Includes, but is not limited to: combustion turbine load reductions (runbacks) associated with: initiation of steam turbine operation, low load steam turbine operation, variability in water/fuel supply, electric generator protection, and variation in turbine operations including but not limited to: combustor flashback, primary combustion zone re-ignition, or combustion blade path spread. Emissions associated with this activity shall not exceed the hourly MSS rate.

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

[4] Includes, but is not limited: baghouse filters, ash silo/transfer filters, coal handling filters, process-related building filters, and combustion turbine air intake filters

[5] Includes, but is not limited to: mgmt. by vacuum truck/dewatering of material in open pits/ponds/sumps/tanks and other closed or open vessels. Material managed include water and sludge materials containing miscellaneous VOCs such as diesel, lube oil, and other waste oils.

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

Emission Sources - Maximum Allowable Emission Rates

Permit Numbers 160538 and PSDTX1582

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

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
CBY51	Combustion Turbine 1 (5) Simple Cycle	NO_x	38.10	65.14
		CO	29.54	113.53
		CO (MSS)	256.70	
		VOC	7.25	24.33
		VOC (MSS)	62.83	
		PM	19.28	27.49
		PM_{10}	19.28	27.49
		$PM_{2.5}$	19.28	27.49
		SO_2	10.81	10.16
		H_2SO_4	7.12	6.69
		NH_3	51.31	95.64
CBY51	Combustion Turbine 1 (5) Combined Cycle	NO_x	32.29	122.86
		NO_x (MSS)	43.96	
		CO	34.40	150.29
		CO (MSS)	533.40	
		VOC	5.63	24.28
		VOC (MSS)	76.83	
		PM	37.33	95.99
		PM_{10}	37.33	95.99
		$PM_{2.5}$	37.33	95.99
		SO_2	12.90	24.07
		H_2SO_4	9.31	16.23
		NH_3	41.83	156.99

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
CBY51-LOV	CTG 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
CBYST-LOV	Steam Turbine 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
AUX-BLR	Auxiliary Boiler	NO_x	3.25	3.25
		CO	3.29	3.29
		VOC	0.48	0.48
		PM	0.66	0.66
		PM_{10}	0.66	0.66
		$PM_{2.5}$	0.66	0.66
		SO_2	0.25	0.12
GAS-HTR	Dewpoint Heater	NO_x	0.12	0.51
		CO	0.36	1.57
		VOC	0.03	0.14
		PM	0.05	0.21
		PM_{10}	0.05	0.21
		$PM_{2.5}$	0.05	0.21
		SO_2	0.03	0.06
C-TOWER1	Cooling Tower	PM	24.21	106.03
		PM_{10}	0.08	0.33
		$PM_{2.5}$	<0.01	<0.01

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
GEN	Diesel Generator Combined Cycle Option	NO_x	2.20	0.55
		CO	11.51	2.88
		VOC	0.18	0.05
		PM	0.10	0.02
		PM_{10}	0.10	0.02
		$PM_{2.5}$	0.10	0.02
		SO_2	0.02	0.01
GENSC	Diesel Generator Simple Cycle Option	NO_x	1.98	0.50
		CO	10.36	2.59
		VOC	0.16	0.04
		PM	0.09	0.02
		PM_{10}	0.09	0.02
		$PM_{2.5}$	0.09	0.02
		SO_2	0.02	0.01
DSL-TNK	Diesel Generator Tank	VOC	0.02	<0.01
FUG-SCR	Ammonia Fugitives (6)	NH_3	0.02	0.10
FUG-NGAS	Natural Gas Fugitives (6)	VOC	<0.01	0.01
FUG-MSS	Planned Maintenance Activity Fugitives	NO_x	<0.01	<0.01
		CO	<0.01	<0.01
		VOC	0.12	<0.01
		PM	0.05	<0.01
		PM_{10}	0.05	<0.01
		$PM_{2.5}$	0.05	<0.01
		NH_3	<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) NO_x - total oxides of nitrogen
CO - carbon monoxide
VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter

Emission Sources - Maximum Allowable Emission Rates

SO_2	-	sulfur dioxide
H_2SO_4	-	sulfuric acid
MSS	-	maintenance, startup, and shutdown
NH_3	-	ammonia

(4) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period.
(5) Planned maintenance, startup and shutdown (MSS) emissions for all pollutants are authorized even if not specifically identified as MSS. During any clock hour that includes one or more minutes of planned MSS that pollutant's maximum hourly emission rate shall apply during that clock hour.
(6) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.

Date: ___________________________

Emission Sources - Maximum Allowable Emission Rates

Permit Number GHGPDTX204

This table lists the maximum allowable emission rates of greenhouse gas (GHG) emissions, as defined in Title 30 Texas Administrative Code § 101.1, for all sources of GHG air contaminants on the applicant's property that are authorized by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities authorized by this permit.

Air Contaminants Data

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
CBY51	Combustion Turbine 1 Simple Cycle	N_2O (5)	-	2
		CH_4 (5)	-	16
		CO_2 (5)	-	864,837
		CO_2e	-	865,716
CBY51	Combustion Turbine 1 Combined Cycle	N_2O (5)	-	4
		CH_4 (5)	-	38
		CO_2 (5)	-	2,052,556
		CO_2e	-	2,054,642
AUX-BLR	Auxiliary Boiler	N_2O (5)	-	<1
		CH_4 (5)	-	<1
		CO_2 (5)	-	10,415
		CO_2e	-	10,426
GAS-HTR	Dewpoint Heater	N_2O (5)	-	<1
		CH_4 (5)	-	<1
		CO_2 (5)	-	4,966
		CO_2e	-	4,971
GEN	Diesel Generator Combined Cycle Option	N_2O (5)	-	<1
		CH_4 (5)	-	<1
		CO_2 (5)	-	590
		CO_2e	-	592

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
GENSC	Diesel Generator Simple Cycle Option	N_2O (5)	-	<1
		CH_4 (5)	-	<1
		CO_2 (5)	-	528
		CO_2e	-	530
FUG-NGAS	Natural Gas Fugitives	CH_4 (5)	-	3
		CO_2 (5)	-	<1
		CO_2e	-	56
SF6FUG	SF6 Insulated Equipment	CO_2e	-	24
		SF_6	-	<1
FUG-MSS	Planned Maintenance Activity Fugitives	CH_4 (5)	-	<1
		CO_2 (5)	-	<1
		CO_2e	-	3

(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) N_2O - nitrous oxide
CH_4 - methane
CO_2 - carbon dioxide
CO_2e - carbon dioxide equivalents based on the following Global Warming Potentials (1/2015): CO_2 (1), N_2O (298), CH_4 (25), SF_6 (22,800).
(4) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period. These rates include emissions from maintenance, startup, and shutdown.
(5) Emission rate is given for informational purposes only and does not constitute enforceable limit.

Date: ________________________