PREVENTION OF SIGNIFICANT DETERIORATION PERMIT FOR GREENHOUSE GAS EMISSIONS ISSUED PURSUANT TO THE REQUIREMENTS AT 40 CFR § 52.21

U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION 6

PSD PERMIT NUMBER:	PSD-TX-1350-GHG
PERMITTEE:	Tenaska Brownsville Partners, LLC 14302 FNB Parkway Omaha, NE 68154-5212
FACILITY NAME:	Tenaska Brownsville Generating Station
FACILITY LOCATION:	8000 Old Alice Road Brownsville, TX 78526

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. § 7470, et seq.), and the Code of Federal Regulations (CFR) Title 40, Section 52.21, and the Federal Implementation Plan at 40 CFR § 52.2305 (effective May 1, 2011 and published at 76 FR 25178), the U.S. Environmental Protection Agency, Region 6 is issuing a *Prevention of Significant Deterioration* (PSD) permit to Tenaska Brownsville Partners, LLC (Tenaska) for Greenhouse Gas (GHG) emissions. The permit applies to the construction of a new natural gas fired combined cycle electric generating plant, Tenaska Brownsville Generating Station (TBGS), to be located in Brownsville, Cameron County, Texas.

Tenaska is authorized to construct a new natural gas-fired combined cycle electric generating plant as described herein, in accordance with the permit application (and plans submitted with the permit application), the federal PSD regulations at 40 CFR § 52.21, and other terms and conditions set forth in this PSD permit in conjunction with the corresponding Texas Commission on Environmental Quality (TCEQ) PSD permit No. PSD-TX-1350. Failure to comply with any condition or term set forth in this PSD permit may result in enforcement action pursuant to Section 113 of the Clean Air Act (CAA). This PSD permit does not relieve Tenaska of the responsibility to comply with any other applicable provisions of the CAA (including applicable implementing regulations in 40 CFR Parts 51, 52, 60, 61, 72 through 75, and 98) or other federal and state requirements (including the state PSD program that remains under approval at 40 CFR § 52.2303).

In accordance with 40 CFR § 124.15(b), this PSD permit becomes effective 30 days after the service of notice of this final decision unless review is requested on the permit pursuant to 40 CFR § 124.19.

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Wren Stenger, Director Date
Multimedia Planning and Permitting Division

Tenaska Brownsville Partners, LLC (PSD-TX-1350-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Draft Permit Conditions

PROJECT DESCRIPTION

Tenaska Brownsville Partners, LLC is proposing to construct a new combined cycle electric generating plant, the Tenaska Brownsville Generating Station (TBGS), in Brownsville, Cameron County, Texas. The TBGS will generate either 400 megawatts (MW) or 800 MW of net electrical power, depending on whether one or two combustion turbines are constructed. The TBGS will consist of the following sources of GHG emissions:

- One or two natural gas-fired combustion turbines;
- One or two natural gas-fired duct burner systems;
- Natural gas piping and metering;
- One diesel fuel-fired emergency electrical generator engine;
- One diesel fuel-fired fire water pump engine;
- One natural gas-fired auxiliary boiler; and
- Electrical equipment insulated with sulfur hexafluoride (SF_6).

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

FIN	EPN	Description
1 2	1 2	1 or 2 Natural Gas-Fired Combined Cycle Combustion Turbines (Combustion Units). Each combustion turbine is equipped with a heat recovery steam generator (HRSG) with duct burners, selective catalytic reduction (SCR), and oxidation catalyst.
4	4	1 Firewater Pump (Combustion Unit). 575 horsepower (hp) Diesel Fired Fire Water Pump rated at 3.8 MMBtu/hr and limited to 100 hours of operation per year for non-emergency activities.
5	5	1 Emergency Generator (Combustion Unit). 2,681 hp Diesel Fired Emergency Generator rated at 19 MMBtu/hr HHV and limited to 100 hours of operation per year for non-emergency activities.
7	7	1 Auxiliary Boiler (Combustion Unit). The boiler has a maximum design heat input rate of 90 MMBtu/hr HHV, and is fired with natural gas.
FUG_GHG	FUG_GHG	Fugitive natural gas emissions from approximately 2,400 valves, pumps, and flanges.
		Fugitive SF_6 emissions from insulated electrical equipment (circuit breakers with 366 lbs SF_6 capacity).

I. GENERAL PERMIT CONDITIONS

A. PERMIT EXPIRATION

As provided in 40 CFR § 52.21(r), this PSD permit shall become invalid if construction:

1. is not commenced (as defined in 40 CFR §52.21(b)(9)) within 18 months after the approval takes effect; or

2. is discontinued for a period of 18 months or more; or

3. is not completed within a reasonable time.

Pursuant to 40 CFR § 52.21(r), EPA may extend the 18-month period upon a written satisfactory showing that an extension is justified.

B. PERMIT NOTIFICATION REQUIREMENTS

Permittee shall notify EPA Region 6 in writing or by electronic mail of the:

1. date construction is commenced, postmarked within 30 days of such date;

2. actual date of initial startup, as defined in 40 CFR § 60.2, postmarked within 15 days of such date; and

3. date upon which initial performance tests will commence, in accordance with the provisions of Section VI, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Condition VI.C.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and maintenance, Permittee shall, to the extent practicable, maintain and operate the facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to EPA, which may include, but is not limited to, monitoring results, review of operating maintenance procedures and inspection of the facility.

D. MALFUNCTION REPORTING

1. Permittee shall notify EPA by mail within 48 hours following the discovery of any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner, which results in an increase in GHG emissions above the allowable emission limits stated in Sections II and III of this permit.

2. Within 10 days of the restoration of normal operations after any failure described in I.D.1., Permittee shall provide a written supplement to the initial notification that includes a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Section II and III, and the methods utilized to mitigate emissions and restore normal operations.

3. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

E. RIGHT OF ENTRY

EPA authorized representatives, upon the presentation of credentials, shall be permitted:

1. to enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this PSD permit;

2. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD permit;

3. to inspect any equipment, operation, or method subject to requirements in this PSD permit; and,

4. to sample materials and emissions from the source(s).

F. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the facilities to be constructed, this PSD permit shall be binding on all subsequent owners and operators. Permittee shall notify the succeeding owner and operator of the existence of the PSD Permit and its conditions by letter; a copy of the letter shall be forwarded to EPA Region 6 within thirty days of the letter signature.

G. SEVERABILITY

The provisions of this PSD Permit are severable, and, if any provision of the PSD permit is held invalid, the remainder of this PSD Permit shall not be affected.

H. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

Permittee shall construct this project in compliance with this PSD permit, the application on which this permit is based, the TCEQ PSD Permit PSD-TX-1350 and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

I. ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology
CAA	Clean Air Act
CCS	Carbon Capture and Sequestration
CEMS	Continuous Emissions Monitoring System
CFR	Code of Federal Regulations
CH_4	Methane
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CT	Combustion Turbine
CTG	Combustion Turbine Generator
DB	Duct Burner
DLNB	Dry Low-NO_x Burner
dscf	Dry Standard Cubic Foot
EF	Emission Factor
EPN	Emission Point Number
FIN	Facility Identification Number
FR	Federal Register
GHG	Greenhouse Gas
gr	Grains
GWP	Global Warming Potential
HRSG	Heat Recovery Steam Generator
HHV	High Heating Value
hr	Hour
LAER	Lowest Achievable Emission Rate
lb	Pound
LDAR	Leak Detection and Repair
MMBtu	Million British Thermal Units
MSS	Maintenance, Startup and Shutdown
NNSR	Nonattainment New Source Review
N_2O	Nitrous Oxides
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
PSD	Prevention of Significant Deterioration
QA/QC	Quality Assurance and/or Quality Control
SCFH	Standard Cubic Feet per Hour
SCR	Selective Catalytic Reduction
SF_6	Sulfur Hexafluoride
STG	Steam Turbine Generator
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TPY	Tons per Year
USC	United States Code
VOC	Volatile Organic Compound

II. Annual Emission Limits

Annual emissions in tons per year (TPY) on a 12-month rolling total shall not exceed the following for the 2x1 or 1x1 operational configurations:

Table 1. Annual Emission Limits for the 2x1 Operational Configuration

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
1	1	Combined Cycle CT (Mitsubishi 501 GAC) equipped with duct burning[3]	CO_2	1,570,400	1,627,099	• 922 lb CO_2/MWh (gross) with and without duct burning on a 12-month rolling average. • Startup and Shutdown emissions are limited to 142 tons CO_2/hr on a 12-month rolling average per turbine • MSS is limited to 712 hrs per year on a 12-month rolling total per turbine. • See Special Conditions III.A.1.
			CH_4	1,782		
			N_2O	40		
2	2	Combined Cycle CT (Mitsubishi 501GAC) equipped with duct burning[3]	CO_2	1,570,400	1,627,099	• 922 lb CO_2/MWh (gross) with and without duct burning on a 12-month rolling average. • Startup and Shutdown emissions are limited to 142 tons CO_2/hr on a 12-month rolling average per turbine. • MSS is limited to 712 hrs per year on a 12-month rolling total per turbine. • See Special Conditions III.A.1.
			CH_4	1,782		
			N_2O	40		
4	4	Fire Water Pump	CO_2	31	31	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Emission Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
5	5	Emergency Generator	CO_2	155	156	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
7	7	Auxiliary Boiler	CO_2	23,060	23,080	• 0.06 Tons CO_2/MMBtu

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
			CH_4	0.43		on a 12-month rolling average. • Good Combustion and Operating Practices. • Heat input limited to 394,200 MMBtu on a 12-month rolling total. See Special Conditions III.B.
			N_2O	0.04		
FUG_ GHG	FUG_ GHG	Component Leak Fugitive Emissions[5]	CH_4	1.0	25	Implementation of AVO Monitoring. See Special Condition III.D.
		SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[4,5]	No Numerical Limit Established[4,5]	Instrumented monitoring and alarm. See Special condition III.D.
Totals[6]			**CO_2**	**3,164,041**	**3,277,606**	
			CH_4	**3,566**		
			N_2O	**80**		
			SF_6	**0.005**		

1. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities. All emissions are expressed in terms of short tons.
2. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298, SF_6 = 22,800
3. The annual emissions limits for each combustion turbine are based on operating at maximum duct burner firing for 5,200 hours per year and includes MSS emissions.
4. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. Fugitive process emissions from EPN FUG_GHG are estimated to be 1.0 TPY of CH_4, 0.0 TPY of CO_2, 0.005 TPY of SF_6, and 142 TPY of CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
6. Total emissions include the PTE for all listed sources. Totals are given for informational purposes only and do not constitute emission limits.

Table 2. Annual Emission Limits for the 1x1 Operational Configuration

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
1	1	Combined Cycle CT (Mitsubishi 501 GAC) equipped with duct burning[3]	CO_2	1,570,400	1,627,099	• 922 lb CO_2/MWh (gross) with and without duct burning on a 12-month rolling average. • Startup and Shutdown emissions are limited to 142 tons CO_2/hr on a 12-month rolling average per turbine. • MSS is limited to 712 hrs per year on a 12-month rolling total per turbine. • See Special Conditions III.A.1.
			CH_4	1,782		
			N_2O	40		
4	4	Fire Water Pump	CO_2	31	31	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Emission Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
5	5	Emergency Generator	CO_2	155	156	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
7	7	Auxiliary Boiler	CO_2	23,060	23,080	• 0.06 Tons CO_2/MMBtu on a 12-month rolling average. • Good Combustion and Operating Practices. • Heat input limited to 394,200 MMBtu on a 12-month rolling total • See Special Conditions III.B.
			CH_4	0.43		
			N_2O	0.04		
FUG_ GHG	FUG_ GHG	Component Leak Fugitive Emissions[5]	CH_4	1.0	25	Implementation of AVO Monitoring. See Special Condition III.D.
		SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[4,5]	No Numerical Limit Established[4,5]	Instrumented monitoring and alarm. See Special condition III.D.
Totals[6]			**CO_2**	**1,593,642**	**1,650,508**	
			CH_4	**1,784**		
			N_2O	**40**		
			SF_6	**0.005**		

1. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities. All emissions are expressed in terms of short tons.
2. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298, SF_6 = 22,800

3. The annual emissions limits for each combustion turbine are based on operating at maximum duct burner firing for 5,200 hours per year and includes MSS emissions.
4. All values indicated as “No Numerical Limit Established” are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. Fugitive process emissions from EPN FUG_GHG are estimated to be 1.0 TPY of CH_4, 0.0 TPY of CO_2, 0.005 TPY of SF_6, and 142 TPY of CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
6. Total emissions include the PTE for all listed sources. Totals are given for informational purposes only and do not constitute emission limits.

III. SPECIAL PERMIT CONDITIONS

A. Requirements for Combined Cycle Electric Generating Units (EGU) (EPNs 1 and 2)

1. BACT Emission Limits for EPN 1 and EPN 2

Table 3. BACT Emission Limits for Combined Cycle Turbines

Turbine Model	Gross Heat Rate[1,2] (Btu/kWh) (HHV)	Output Based Emission Limit[1,2] (lb CO_2/MWh, gross)	MSS Emission BACT Limit[3] (tons CO_2/hr)
EPN 1: Combined Cycle CT (Mitsubishi 501 GAC) equipped with duct burning	7,500	922	142
EPN 2: Combined Cycle CT (Mitsubishi 501 GAC) equipped with duct burning	7,500	922	142

[1]Limits are based on the high heating value of the natural gas fuel (Btu) and the electric output at the generator terminals (MW, gross). These limits apply with and without duct burner firing.
[2] Limits are based on a 12-month rolling average per turbine.
[3] Limit is based on a 12-month rolling average per turbine and 712 hours of MSS on a 12-month rolling total per turbine.

a. For facility operations in a 1 x 1 plant configuration operation, compliance with the 922 lb CO_2/MWh output based emission limit shall be determined by the following method. The CO_2 mass emission values shall be calculated over each operational hour of the compliance period and summed (excluding MSS emissions). The summed hourly CO_2 mass emission values shall be divided by the summed hourly total gross electrical output. Compliance shall be demonstrated on a 12-month rolling average and includes duct burning.

b. For facility operations in a 2 x 1 plant configuration operation, compliance with the 922 lb CO_2/MWh output based emission limit shall be determined as follows:

i. The hourly gross electric output from the steam turbine shall be apportioned to the two combustion turbines/duct burner sets based on either the measured steam load or measured fuel consumption and calculated heat input. A plan to demonstrate the apportionment of the gross electric output shall be submitted within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days of the date of initial startup of the combustion turbine generator.

ii. The CO_2 mass emission values shall be calculated over each operational hour of the compliance period and summed (excluding MSS emissions). The summed hourly CO_2 mass emission values shall be divided by the combined sum of the total gross electrical output from the steam turbine (as determined by the corresponding apportionment calculations represented in the plan) and the total gross electrical load from the combustion turbine generators. The resulting quotient is added to the sum of quotients of the previous 11 operating months and divided by 12 to determine compliance with the 12-month rolling average.

c. Upon initial demonstration that that the combustion turbines comply with the emission limit via emission tests, the Permittee shall not exceed the gross heat rate, Btu/kWh, on a 12-month rolling average. To determine the heat rate, the permittee shall use the procedure provided in 40 CFR Part 75, Appendix F § 5.5.2, GCV of the fuel combusted, and the measured electrical output (kWh), gross basis, for the corresponding compliance period.

d. The Permittee shall not discharge or cause the discharge of emissions into the atmosphere in excess of the limits in tons of CO_2e on a 12-month rolling total as listed in Table 1 or Table 2, as applicable. The 1,627,099 TPY of CO_2e per turbine is applicable during all times, including MSS, and includes duct burning.

e. The duct burners are limited to 5,200 hours of operation per year.

f. Startup and Shutdown events are limited to 712 hours per year per turbine on a 12-month rolling total basis and shall comply with the MSS BACT emission limit of 142 tons CO_2 per hour on a 12-month rolling average.

2. Emissions Monitoring for EPN 1 and EPN 2

a. Upon initial demonstration that the combustion turbines comply with the emissions limit via emission tests, the Permittee shall not exceed the CO_2e annual emission limit from Table 1 or Table 2, as applicable. To determine the amount of CO_2e, the Permittee shall calculate the amount of CO_2, CH_4 and N_2O in short tons per month based on the equation G-4 of 40 CFR Part 75, Appendix G and 40 CFR Part 98, Appendix C, and the monthly hours of operation on a 12-month rolling total (including MSS). The Permittee shall also use the default CH_4 and N_2O emission factors contained in Table C-2 of 40 CFR Part 98 and the measured actual hourly heat input (HHV) to determine compliance with the CH_4 and N_2O emission limits (including MSS). The short tons per month values are multiplied by the respective Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1 to calculate the amount of CO_2e emitted in short TPY. The resulting CO_2e value is added to the previous 11 months to determine the 12 month rolling total of CO_2e emissions.

b. As an alternative, the Permittee may install and operate a volumetric stack gas flow monitor and associated data acquisition and handling system in accordance with the CO_2 CEMS system provided in 40 CFR § 75.10(a)(3) and (a)(5). If a CO_2 CEMS system is utilized, the hourly CO_2 emission value shall be measured by installing and operating a volumetric stack gas flow monitor or calculating the volumetric stack gas flow by the procedures of 40 CFR Part 75, Appendix D and associated data acquisition and handling system in accordance with the CO_2 CEMS system provided in 40 CFR § 75.10.

c. In accordance with 40 CFR Part 75, Appendix D and 40 CFR Part 60, the Permittee shall ensure that all required inline fuel flow meters are installed, a periodic schedule for GCV fuel sampling is initiated and all certification tests are completed on or before the earlier of 90 unit operating days or 180 calendar days after the date the unit commences commercial operation (as defined in 40 CFR § 72.2). The flow meter data shall be automatically recorded with a data acquisition and handling system. Permittee shall perform monthly GCV fuel sampling according to the procedures for pipeline natural gas in 40 CFR Part 75, Appendix F, § 5.5.2. The measured hourly fuel flow and GCV shall be used in Equation F-20 in 40 CFR Part 75, Appendix F, § 5.5.2 to calculate the hourly heat input.

d. The Permittee shall ensure compliance with the specifications and test procedures for fuel flow meter and/or CO_2 emission monitoring system at stationary sources, 40 CFR Part 75 and 40 CFR Part 60.

e. The Permittee shall meet the appropriate quality assurance requirements specified in 40 CFR Part 75, Appendixes D and F and 40 CFR Part 60 for the fuel flow meter and/or CO_2 emission monitoring system.

3. Work Practice and Operational Requirements for EPN 1 and EPN 2

a. The fuel for EPN 1 and EPN 2 is limited to pipeline quality natural gas. Upon request, Permittee shall provide a sample and/or analysis of the fuel fired or shall allow a sample to be taken by EPA for analysis.

b. The flow rate of the fuel combusted in the combustion turbine and duct burners shall be measured and recorded using an in-line flow meter and automatically record the data with a data acquisition and handling system. The steam load and/or heat input to the steam turbine shall also be measured or calculated and recorded.

c. The Permittee shall measure and record the energy output of the apportioned steam turbine and combustion turbine(s) (MWh, gross) on an hourly basis.

d. On or before the date of initial performance test required by 40 CFR § 60.8, and thereafter, the Permittee shall install, and continuously operate, and maintain the HRSGs so emissions are at or below the emissions limits specified in this permit.

e. The Permittee shall perform an annual compliance test of CO_2, at or above 90% of maximum load operations and conducted under such conditions to ensure representative performance of the affected facility. The conditions of the performance tests shall be recorded and made available for review upon request.

f. On or after initial performance testing, the Permittee shall use the combustion turbines, Heat Recovery Steam Generators, Steam Turbines and Plant-wide energy efficiency processes, work practices and designs as represented in the permit application.

4. Requirements during Startup and Shutdown for EPN 1 and EPN 2

a. Permittee shall minimize emissions during startup and shutdown activities by operating and maintaining the facility in accordance with good air pollution control practices, safe operating practices, and protection of the facility.

b. Emissions during startup and shutdown activities shall be minimized by limiting the duration of operation in startup and shutdown mode as follows:

   i. A startup is defined as the period that begins when the data acquisition and handling system measures fuel flow to the combustion turbine and ends when both the combustion turbine generator load reaches 50 percent and the SCR has been placed into operation or 60 minutes, whichever comes first.

   ii. A shutdown is defined as the period that begins when the combustion turbine generator output drops below 50 percent load and ends when there is no longer measureable fuel flow to the CTG/HRSG.

   iii. Startup and shutdown events are limited to 712 hours per year per CT.

c. Permittee must record the time, date, fuel heat input (HHV) in mmBtu/hr and the duration of each startup and shutdown event in order to calculate the total CO_2e emissions resulting from MSS events. The calculated CO_2e from MSS events is added to the calculated CO_2e from normal operation. The records must include hourly CO_2 emission levels as calculated using the fuel flow meter (or measured using the CO_2 CEMS with volumetric stack gas flowrate) and the calculations based on the actual heat input for the CO_2, CO_2e, N_2O, and CH_4 emissions during each startup and shutdown event based on the equations represented in the permit application. These records must be kept for five (5) years following the date of such event.

d. To demonstrate compliance with the MSS BACT limitation, the permittee shall record and maintain documentation to support the number of hours each CTG operates in startup and shutdown mode. The number of hours for startup and shutdown shall not exceed 712 hours on a 12-month rolling total basis. The amount of fuel used during MSS is recorded and used to calculate the amount of CO_2 per hour and compared to the MSS BACT limit of 142 tons CO_2/hr on a 12-month rolling average basis.

e. During startup and shutdown, emissions from EPN 1 and EPN 2 shall comply with all provisions of MSS BACT emission limitation in Special Condition III.A.1.

B. BACT Emission Limit for Auxiliary Boiler (EPN 7)

1. Boiler shall combust only pipeline quality natural gas.
2. Compliance with the 0.06 Ton CO_2/MMBtu emission limit shall be determined by the hourly heat input and the calculated emissions using Equation C-1 from 40 CFR Part 98, Subpart C, which is based on metered fuel usage and the emission factor for pipeline quality natural gas. The resulting CO_2 value is converted from metric tons to short tons and is divided by the corresponding measured heat input on a monthly basis. The calculated Ton CO_2/MMBtu is compared to the BACT limit of 0.06 Tons CO_2/MMBtu on a 12-month rolling average.
3. The heat input to the auxiliary boiler shall not exceed 394,200 MMBtu on a 12-month rolling total basis.
4. To determine compliance with the CO_2e limit, the calculated CO_2 emissions from Equation C-1 from 40 CFR Part 98, Subpart C and the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1 shall be used.
5. Permittee shall measure and record the fuel flow rate using an inline flow meter and automatically record the data with a data acquisition and handling system.
6. Permittee shall calibrate and perform preventative maintenance checks of the fuel gas flow meters and document annually.
7. Permittee shall utilize good engineering practice to complete an annual operational performance assessment in accordance with the recommendations provided by the equipment manufacturer. This assessment shall include a visual inspection to evaluate the pressure vessel care and repair, chemical cleaning, water column, safety valves and care of refractory. If the results of any inspection are not satisfactory, the deficiencies shall be recorded and the permittee shall promptly take necessary corrective action, recording each action with the date completed.
8. The maximum hourly heat input (firing rate) for the auxiliary boiler is 90 MMBtu/hr HHV.
9. The hourly heat input shall be calculated and recorded daily to demonstrate compliance with the firing rate in III.B.8.
10. Records of the heat input to the auxiliary boiler shall be recorded daily. A 12-month rolling total of boiler heat input limit shall be calculated to demonstrate compliance with the limitation in III.B.3.
11. Permittee shall install, operate, and maintain an automated air/fuel control system.
12. Permittee shall calibrate and perform preventative maintenance on the air/fuel control analyzers once per quarter, at a minimum.
13. Oxygen analyzers shall continuously monitor and record oxygen concentration in the boiler. Alarms shall be set to sound when the flue gas oxygen content is outside of the established range and corrective action shall be taken any time an alarm is sounded. If the alarm is sounded, a record of the alarm and the associated corrective action shall be

recorded and the permittee shall promptly take necessary corrective action, recording each action with the date completed.

14. Compliance with the Annual Emission Limit shall be demonstrated on a 12-month total, rolling monthly, calculated in accordance with 40 CFR § 98.33(a)(1)(i).

C. Requirements for the Fire Water Pump (EPN 4) and Emergency Generator (EPN 5)

1. The Fire Water Pump (EPN 4) and Emergency Generator (EPN 5) diesel engines are authorized to fire diesel fuel containing no more than 0.0015 percent sulfur by weight. Upon request, Permittee shall provide a sample and/or an analysis of the fuel fired in the engines or shall allow a sample to be taken by EPA for analysis.
2. The Fire Water Pump and Emergency Generator are limited to 100 hours of non-emergency operation per year for each unit and a heat input value of 3.8 MMBtu/hr HHV and 19 MMBtu/hr HHV for the Fire Water Pump and the Emergency Generator, respectively. Compliance with the 100-hour, non-emergency operational requirement is determined on a 12-month rolling basis.
3. The Fire Water Pump and Emergency Generator shall meet the applicable monitoring and recordkeeping requirements as required in 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
4. Permittee shall install and maintain an operational non-resettable elapsed time meter for the Fire Water Pump and Emergency Generator.
5. Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the Fire Water Pump and Emergency Generator, including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to performance tests and monitoring of the emergency generator and fire pump equipment; for each diesel fuel oil delivery, documents from the fuel supplier certifying compliance with the fuel sulfur content limit of Special Condition III.C.1., fuel heat input values and hours of operation required in Special Condition III.C.2.; and all other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.

D. Requirements for Natural Gas Fugitive Emission Sources and SF6 Insulated Equipment (EPN FUG_GHG)

1. The Permittee shall implement an auditory/visual/olfactory (AVO) method for detecting leaking from natural gas piping components, and make observations on a daily basis.
2. The emissions of SF_6 from the circuit breakers containing SF_6 shall be calculated annually (calendar year) in accordance with the mass balance approach provided in equation DD-1 of the Mandatory Greenhouse Gas Reporting rules for Electrical

Transmission and Distribution Equipment Use, 40 CFR Part 98, Subpart DD. Permittee shall not exceed insulated circuit breaker SF_6 capacity of 366 lbs.

3. Permittee shall equip the circuit breakers with a low pressure alarm and a low pressure lockout. The SF_6 leak detection system shall be guaranteed to achieve a leak rate of 0.5% by year by weight or less.
4. Permittee shall maintain a file of all records, data measurements, reports and documents related to the fugitive emission sources including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to compliance with the Monitoring and Quality Assurance and Quality Control (QA/QC) procedures outlined in 40 CFR § 98.304.
5. The Permittee provided data to show that minimal quantities of natural gas are released to the atmosphere during turbine fuel line purging associated with shutdown events and when performing repair or maintenance on small equipment and fugitive components. Emissions related to these types of activity are not expected to exceed 7.65 ton per year of CH_4 (191 tons per year of CO_2e) per year.

IV. RECORDKEEPING AND REPORTING

1. In order to demonstrate compliance with the GHG emission limits in Table 1, the Permittee will monitor the following parameters and summarize the data on a calendar month basis.
   a. Operating hours for all air emission sources;
   b. The natural gas fuel usage for all combustion sources, using continuous fuel flow monitors; and
   c. Monthly GCV fuel sampling for natural gas.
2. Permittee shall implement an AVO program under Special Condition D.1. and keep records of the monitoring results, as well as the repair and maintenance records.
3. Permittee shall maintain all records, data, measurements, reports, and documents related to the operation of the facility, including, but not limited to, the following: all records or reports pertaining to significant maintenance performed on any system or device at the facility; duration of startup, shutdown; the initial startup period for the emission units; pollution control units; malfunctions; all records relating to performance tests, calibrations, checks, and monitoring of combustion equipment; duration of an inoperative monitoring device and emission units with the required corresponding emission data; and all other information required by this permit recorded in a permanent form suitable for inspection. The records must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.
4. Permittee shall maintain records of all GHG emission units and CO_2 emission certification tests and monitoring and compliance information required by this permit.

5. Permittee shall maintain records and submit a written report of all GHG excess emissions to EPA semi-annually, except when: more frequent reporting is specifically required by an applicable requirement; or the Administrator or authorized representative, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:
    a. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;
    b. Applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);
    c. A statement in the report of a negative declaration; that is; a statement when no excess emissions occurred or when the monitoring equipment has not been inoperative, repaired or adjusted; and
    d. Any failure to conduct any required source testing, monitoring, or other compliance activities.
6. Excess emissions shall be defined as any period in which the facility emissions exceed a maximum emission limit set forth in this permit.
7. Excess emissions indicated by GHG emission source certification testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.
8. All records required by this PSD permit shall be retained and remain accessible for not less than 5 years following the date of such measurements, maintenance, and reporting.

V. SHAKEDOWN PERIODS

The combustion turbine emission limits and requirements in conditions II., III.A.1., and III.B. shall not apply during combustion shakedown periods. Shakedown is defined as the period beginning with initial startup and ending no later than initial performance testing, during which the Permittee 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. The requirements of special condition I.C. of this permit shall apply at all times.

VI. PERFORMANCE TESTING

A. The Permittee shall perform stack sampling and other testing to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the stacks of the Combustion Turbines and HRSGs (EPNs 1 and 2) and the Auxiliary Boiler (EPN 7) to determine the initial compliance with the CO_2 emission limits established in this permit. Sampling shall be conducted in accordance with 40 CFR § 60.8 and EPA Method 3a or 3b for the concentration of CO_2.

1. Multiply the CO_2 hourly average emission rate (lbs/hr) determined under maximum operating test conditions by 4.38 for the combustion turbines and 2.19 for the auxiliary boiler.
2. If the above calculated CO_2 emission total does not exceed the tons per year (TPY) specified on Table 1, no compliance strategy needs to be developed.
   If the above calculated CO_2 emission total exceeds the tons per year (TPY) specified in Table 1, the facility shall:
   a. Document the potential to exceed in the test report; and
   b. Explain within the report how the facility will assure compliance with the CO_2 emission limit listed in Table 1.

B. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility, performance tests(s) must be conducted and a written report of the performance testing results furnished to the EPA. Additional sampling may be required by TCEQ or EPA.

C. Permittee shall submit a performance test protocol to EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an EPA observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.

D. The turbine shall be tested at or above ninety percent (90%) of maximum load operations for the atmospheric conditions which exist during testing for the initial and annual tests. The duct burners shall be tested at its maximum firing rate within the mechanical limits of the equipment for the atmospheric conditions which exists during the performance test while the turbine is operating as close to base load as possible. The tested turbine load shall be identified in the sampling report. The permit holder shall present in the performance test protocol the manner in which stack sampling will be executed in order to demonstrate compliance with the emissions limits contained in Section II.

E. Air emissions from each CTG exhaust stack shall be initially tested while firing at the minimum load in the normal operating range in addition to the initial ninety percent performance test. The normal operating range consistent with emission limits is to be determined during stack testing. Air emissions that will be sampled and analyzed while at the minimum load include (but are not limited to) CO_2.

F. Performance tests must be conducted under such conditions to ensure representative performance of the affected facility. The owner or operator must make available to the EPA such records as may be necessary to determine the conditions of the performance tests.

G. The owner or operator shall provide, or cause to be provided, performance testing facilities as follows:

1. Sampling ports adequate for test methods applicable to this facility,
2. Safe sampling platform(s),
3. Safe access to sampling platform(s), and
4. Utilities for sampling and testing equipment.

H. Unless otherwise specified, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted for the time and under the conditions specified in the applicable standard. For purposes of determining compliance with an applicable standard, the arithmetic mean of the results of the three runs shall apply.

VII. Agency Notifications

Permittee shall submit GHG permit applications, permit amendments, and other applicable permit information to:

Multi Media Planning and Permitting Division
EPA Region 6
1445 Ross Avenue (6 PD-R)
Dallas, TX 75202
Email: Group R6AirPermits@EPA.gov

Permittee shall submit a copy of all compliance and enforcement correspondence as required by this Approval to Construct to:

Compliance Assurance and Enforcement Division
EPA Region 6
1445 Ross Avenue (6EN)
Dallas, TX 75202