NRG Texas Power LLC
1201 Fannin
Houston, Tx 77002

NOVEMBER 26, 2012

VIA EMAIL TRANSMITTAL

Mr. Jeff Robinson
Chief, Air Permit Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

RE: **Application for PSD Air Quality Permit**
Greenhouse Gas Emissions
Unit 5, S.R. Bertron Generating Station
LaPorte, Harris County, Texas
NRG Texas Power LLC

Dear Mr. Robinson:

NRG Texas Power LLC (NRG Texas) is submitting the enclosed application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions for our proposed Unit 5 electric generating facilities at the S.R. Bertron Generating Station located in LaPorte, Harris County, Texas.

The state NSR and PSD permit application for this project submitted to TCEQ is also enclosed. NRG Texas is committed to working with EPA to ensure timely review of our permit application. Additional analyses required to support this application are underway, and NRG Texas expects to submit these under a separate cover within the next 60 days. These additional analyses include:

- Biological Assessment (Endangered Species Act),
- Texas Historical Commission Request for Concurrence (National Historic Preservation Act),
- Essential Fish Habitat Assessment (Magnuson-Stevens Fishery Conservation and Management Act), and

Should you have questions concerning this application, or require further information, please do not hesitate to contact me at (713) 537-2146 or craig.eckberg@nrgenergy.com.

Sincerely,

C. R. Eckberg

Craig R. Eckberg
Senior Manager
Environmental Business

Enclosure(s)

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Application for a Prevention of Significant Deterioration Air Permit for Greenhouse Gas Emissions

NRG Texas Power LLC
S.R. Bertron Station
Unit 5
LaPorte, Harris County, Texas

November 2012

United States | Canada | Brazil | UK | Ireland | Netherlands
Australia Asia Pacific | Russia | Middle East | Africa

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Section 1
Introduction

NRG Texas Power LLC (NRG Texas) owns and operates the Bertron Electric Generating Station in LaPorte, Harris County, Texas. NRG Texas proposes to construct an additional electric generating unit at the Bertron Station. The new facility will be a combined cycle generating unit in either a 2x2x1 or 2x2x2 configuration (two combustion turbines, two supplementally fired (duct burners) heat recovery steam generators (HRSGs), and either one or two steam turbines). The gas turbines will be one of three options: 1) Siemens F(5) turbines, 2) MHI 501GAC turbines, or 3) General Electric 7FA.05 turbines. Initial operation of the units (Phase 1) will be in a simple cycle mode until the construction of the HRSGs and steam turbine(s) is completed. Following startup of the HRSGs and steam turbine(s) (Phase 2), the capability to operate the turbines in a simple cycle mode will be retained. The net baseload generation capacity of the new electric generating unit at the completion of Phase 2 will approach 800 MW (820 MW gross, 69 °F case) for the Siemens F(5) option, 885 MW (910 MW gross, 69 °F case) for the MHI 501GAC option and 730 MW (750 MW gross, 69 °F case) for the GE 7FA.05 option. All of the proposed turbines and duct burners will be fired exclusively with natural gas.

NRG Texas has submitted an application to TCEQ for an air quality permit for this project that includes all applicable state New Source Review (NSR) requirements and Prevention of Significant Deterioration (PSD) review requirements for CO, $PM/PM_{10}/PM_{2.5}$, and H_2SO_4. The project emissions increases also exceed the 75,000 tpy PSD applicability threshold for greenhouse gases (GHG). Permitting of GHG emissions in Texas is currently conducted by the USEPA Region VI; therefore, a separate PSD permit application is required to be submitted to the USEPA for GHG emissions. This document constitutes NRG Texas' application for the required GHG PSD permit. The application is organized as follows:

Section 1 identifies the project for which authorization is requested and presents the application document organization.

Section 2 contains administrative information and completed TCEQ Federal NSR applicability Tables 1F and 2F.

Section 3 contains an area map showing the facility location and a plot plan showing the location of each emission points with respect to the plant property.

Section 4 contains more details about the proposed modifications and changes in operation and a brief process description and simplified process flow diagram.

Section 5 describes the basis of the calculations for the project GHG emissions increases and includes the proposed GHG emission limits.

Section 6 includes an analysis of best available control technology for the new sources of GHG emissions.

Appendix A contains GHG emissions calculations for the affected facilities.

Section 2
Appliction Forms

This section contains the following forms:

- Administrative Information
- TCEQ Table 1F
- TCEQ Table 2F
- TCEQ Table 3F

Tables 1F, 2F, and 3F are TCEQ's federal NSR applicability forms. Because this application covers only GHG emissions, and permitting of other pollutants is being conducted by TCEQ, these forms only include GHG emissions. As shown in both the Table 1F and 2F, GHG emissions from the project exceed 75,000 tpy of CO_2e; therefore, a Table 3F, which includes the required netting analysis, is also included. The net increase in GHG emissions exceeds 75,000 tpy of CO_2e; therefore, PSD review is required.

Administrative Information

A. Company or Other Legal Name: NRG Texas Power LLC		
B. Company Official Contact Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): Mr. Craig R. Eckberg		
Title: Senior Manager, Air Resources		
Mailing Address: 1201 Fannin, Suite 8802		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-537-2146	Fax No.: 713-795-7431	E-mail Address: Craig.Eckberg@nrgenergy.com
C. Technical Contact Name: Mr. Craig R. Eckberg		
Title: Senior Manager, Air Resources		
Company Name: NRG Texas Power LLC		
Mailing Address: 1201 Fannin, Suite 8802		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-537-2146	Fax No.: 713-795-7431	E-mail Address: Craig.Eckberg@nrgenergy.com
D. Facility Location Information:		
Street Address: 2012 Miller Cut Off Road		
If no street address, provide clear driving directions to the site in writing:		
City: LaPorte	County: Harris	ZIP Code: 77571
E. TCEQ Account Identification Number (leave blank if new site or facility): HG-0358-Q		
F. TCEQ Customer Reference Number *(leave blank if unknown)*: CN603207218		
G. TCEQ Regulated Entity Number *(leave blank if unknown)*: RN100825389		
H. Site Name: S.R. Bertron Electric Generating Station		
I. Area Name/Type of Facility: Electric Generating Unit		☒ Permanent ☐ Portable
J. Principal Company Product or Business: Electric Services		
K. Principal Standard Industrial Classification Code: 4911		
L. Projected Start of Construction Date: 04/01/2013	Projected Start of Operation Date: 11/01/2013	
SIGNATURE		
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief.		
NAME: Mr. Craig R. Eckberg, Senior Manager, Air Resources		
SIGNATURE: C.R. E [signature] *Original Signature Required*		
DATE: 26 Nov 12		

TCEQ

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	**TBD**	Application Submittal Date:	**November 2012**
Company:	**NRG Texas Power LLC**		
RN:	**100825389**	Facility Location: **2012 Miller Cut Off Road**	
City:	**LaPorte**	County: **Harris**	
Permit Unit I.D.:	**Combined Cycle Plant**	Permit Name: **Bertron Combined Cycle Plant**	
Permit Activity: New Source ___ Modification _X_			
Project or Process Description: **Install New Combustion Turbines for Electric Power Generation**			

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS											
	Ozone		CO	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	H_2S	TRS	Pb	Other[1]
	VOC	NO_x										CO2e
Nonattainment? (yes or no)	Yes	Yes	No	No	No	No	No	No	NA	NA	No	NA
Existing site PTE (tpy)?	>100	>100	>100				>100					>100,000
Proposed project emission increases (tpy from 2F)[2]	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2,955,146
Is the existing site a major source? [3]If not, is the project a major source by itself?	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	Yes
Significance Level (tpy)	5	5	100	25	15	10	40	40	10	10	0.6	75,000
If site is major, is project increase significant?	Yes	NA	Yes	Yes	Yes	Yes	NA	No	No	No	No	Yes
If netting required, estimated start of construction?								1-Apr-13				
Five years prior to start of construction								1-Apr-08				contemporaneous
Estimated start of operation								1-Nov-13				period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	2,955,146
FNSR APPLICABLE? (yes or no)												Yes

***Facility operates under a NO_x PAL**

1 Other PSD pollutants.

2 Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR § 51.166(b)(23).

3 Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR § 51.166(b)(1).

The representations made above and on the accompanying tables are true and correct to the best of my knowledge.

Signature	Title	Date
C. R. [illegible]	Senior Manager	26 Nov 12

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	**CO2e**	**Permit No.:**	**TBD**
Baseline Period:	**NA**	**Project Name:**	**Combined Cycle Plant**

	Affected or Modified Facilities[2]			Permit No.	Actual Emissions[3] (tons/yr)	A Baseline Emissions[4] (tons/yr)	B Proposed Emissions[5] (tons/yr)	Projected Actual Emissions (tons/yr)	Difference (B-A)[6] (tons/yr)	Correction[7] (tons/yr)	Project Increase[8] (tons/yr)
	FIN	EPN	Facility Name								
1	SRB51	SRB51	Combustion Turbine 1 (combined cycle)	TBD		-	1,468,007		1,468,007	0	1,468,007
2	SRB52	SRB52	Combustion Turbine 2 (combined cycle)	TBD		-	1,468,007		1,468,007	0	1,468,007
3	AUX-BLR	AUX-BLR	Auxiliary Boiler	TBD		-	18,720		18,720	0	18,720
4	FUG-NGAS	FUG-NGAS	Fugitives: Natural Gas	TBD		-	394		394	0	394
5	INS-SF6	INS-SF6	Circuit Breaker Insulation (SF6) Leaks	TBD		-	18		18	0	18
6									-	-	-
7									-	-	-
8									-	-	-
9									-	-	-
10								-	-	-	-
11								-	-	-	-
12								-	-	-	-
13								-	-	-	-
14								-	-	-	-
15								-	-	-	-
16								-	-	-	-
17								-	-	-	-
18								-	-	-	-
19								-	-	-	-
										Page Subtotal[9]:	**2,955,146**
										Project Total:	**2,955,146**

*

Table 3F
Project Contemporaneous Changes

Company: **NRG Texas Power LLC**

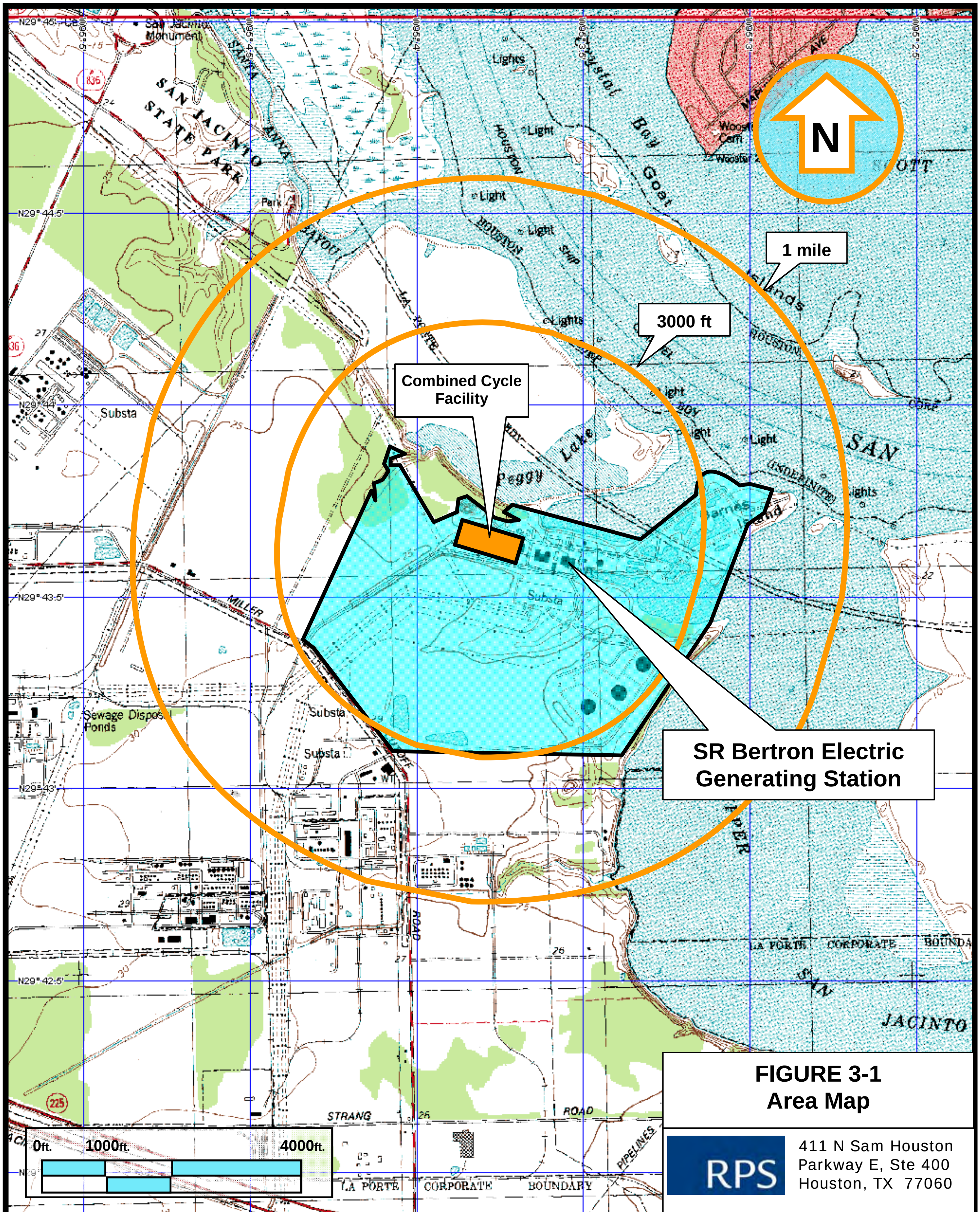
Permit Application No. **TBD**

Criteria Pollutant: **CO2e**

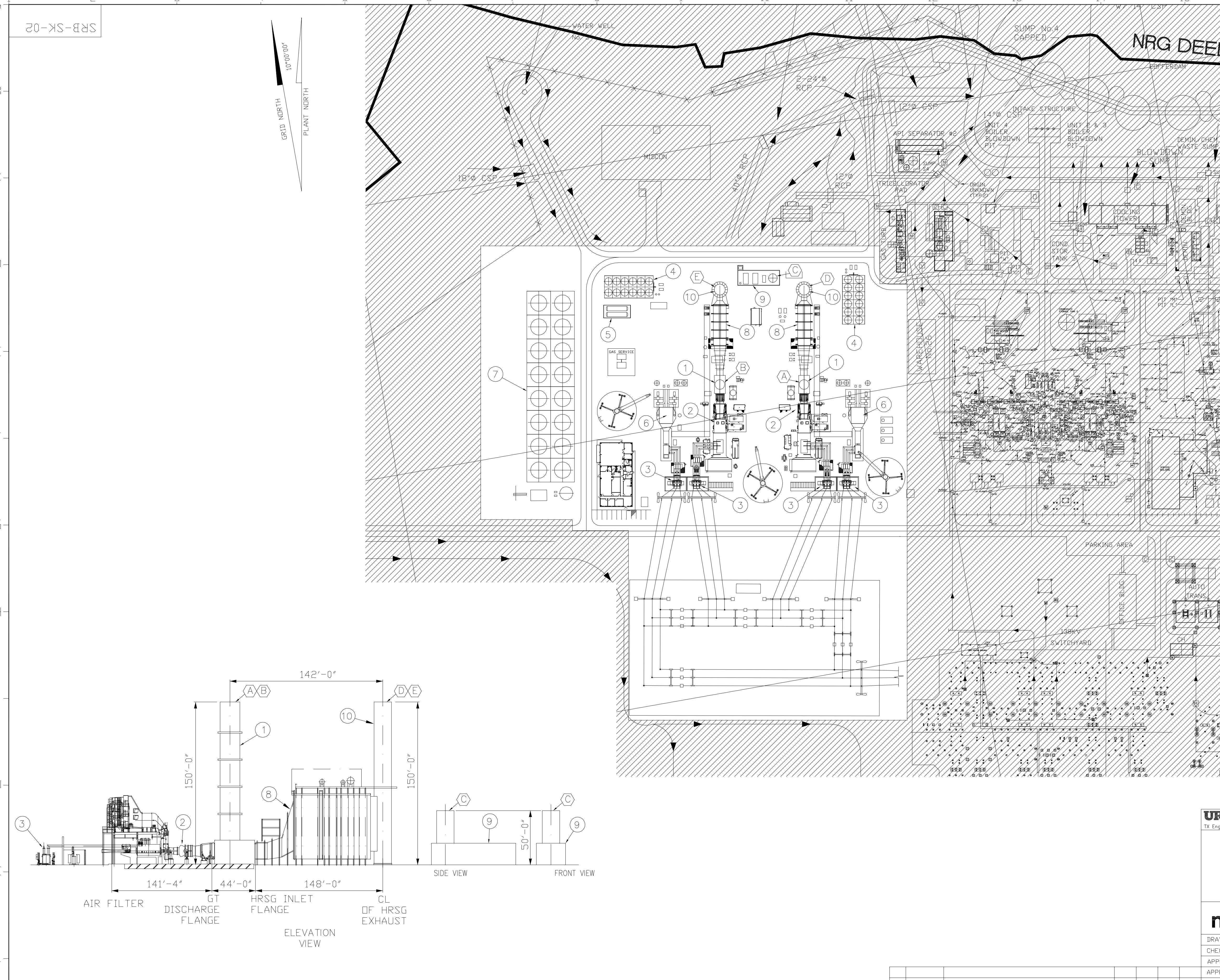
No.	PROJECT DATE	EMISSION UNIT AT WHICH REDUCTION OCCURED FIN	EPN	PERMIT NUMBER	PROJECT NAME OR ACTIVITY	A PROPOSED EMISSIONS (tons / year)	B BASELINE EMISSIONS (tons / year)	C DIFFERENCE (A-B) (tons / year)	CREDITABLE DECREASE OR INCREASE (tons / year)
1	11/1/2013	SRB51	SRB51	TBD	Combined Cycle Plant	1,468,007	0	1,468,007	1,468,007
2	11/1/2013	SRB52	SRB52	TBD	Combined Cycle Plant	1,468,007	0	1,468,007	1,468,007
3	11/1/2013	AUX-BLR	AUX-BLR	TBD	Combined Cycle Plant	18,720	0	18,720	18,720
4	11/1/2013	FUG-NGAS	FUG-NGAS	TBD	Combined Cycle Plant	394	0	394	394
5	11/1/2013	INS-SF6	INS-SF6	TBD	Combined Cycle Plant	18	0	18	18
6								0	0
7								0	0
8								0	0
9								0	0
10								0	0
11								0	0
12								0	0
13								0	0
14								0	0
15								0	0
16								0	0
17								0	0
18								0	0
19								0	0
20								0	0
21								0	0
22								0	0
23								0	0
								PAGE SUBTOTAL:	2,955,146
	Summary of Contemporaneous Changes							TOTAL :	**2,955,146**

Section 3
Area Map and Plot Plan

An area map showing the general location of the facility and a 3,000 ft. radius is included as Figure 3-1. Figure 3-2 is a plot plan that shows the proposed layout of the Unit 5 facilities. The layouts shown are for the 2x2x2 configuration and are for Phase 2 (combined cycle) of the project. In Phase 1 (simple cycle), the only emission points will be the turbine exhaust stacks, which are labeled as the by-pass stacks on the Phase 2 layouts shown. The 2x2x1 configuration, if used, would include one larger steam turbine instead of the two steam turbines shown in Figure 3-2. The steam turbines are not emission points, and the remainder of the equipment layout would not change significantly from that which is shown for the 2x2x2 configuration.



3-D TopoQuads Copyright © 1999 DeLorme Yarmouth, ME 04096 Source Data: USGS 700 ft Scale: 1 : 24,000 Detail: 13-0 Datum: WGS84



LEGEND

1. BY-PASS STACK
2. GAS TURBINE
3. TRANSFORMER
4. AUXILIARY COOLING TOWER
5. AMMONIA STORAGE
6. STEAM TURBINE
7. COOLING TOWERS
8. HRSG
9. AUXILIARY BOILER
10. MAIN STACK

REPRESENTS EXISTING PLANT AREA

EMISSION POINTS

A – BY-PASS STACK
E300685.40
N3290298.90

B – BY-PASS STACK
E300732.80
N3290298.90

C – AUX. BOILER STACK
E300702.93
N3290348.65

D – MAIN STACK
E300685.40
N3290342.18

E – MAIN STACK
E300732.80
N3290342.18

NOTE

COORDINATES ARE LISTED AS USING THE UTM GRID SYSTEM.
NORTH AMERICAN DATUM OF 1983 (NAD83)
WORLD GEODETIC SYSTEM OF 1984 (WGS84) PROJECTION AND 1000-METER GRID: UNIVERSAL TRANSVERSE MERCATOR, ZONE 15R 10,000 FOOT TICKS: TEXAS COORDINATE SYSTEM OF 1983 (SOUTH CENTRAL ZONE)

URS
TX Engr. Lic. F-02660
1111 Fannin Street Suite 1400
Houston, Texas 77002
713-951-4300

S.R. BERTRON
UNIT #5
PROPOSED LAYOUT
PHASE 2
FIGURE 3-2

NRG Energy, Inc.

DRAWN 6-11-12	JPF	SCALE NONE	
CHECKED		DRAWING NUMBER	
APPROVED		SRB-SK-02	
APPROVED		SH.	
DISK ID:	FILE NAME:		

NO.	DATE	REVISION	BY	CHK.	APP.	APP.

Section 4
Project and Process Description

4.1 Electric Generating Unit

The proposed electric generating unit will consist of two gas turbine-generators (GT), two heat recovery steam generators (HRSG), and either one or two extracting/condensing steam turbines (referred to as a 2x2x2 or 2x2x1 configuration, respectively), and other mechanical and electrical auxiliary systems. With the exception of an additional lube oil vent on the second steam turbine in the 2x2x2 configuration, the emissions are the same for 2x2x2 and 2x2x1. Three turbine options are being considered: GE 7FA.05, Siemens F(5), and MHI 501GAC. The basic process described in this section will be the same regardless of the turbines selected. A process flow diagram (PFD) for the facility is shown in Figure 4-1. The following process description is for the facility operating in combined cycle mode at 100% load with the ambient temperature at 69°F and 60% relative humidity. The operations will vary with the ambient temperature, relative humidity, and load conditions. In addition, the values presented below are approximate and are subject to change per final design. During Phase 1 operation prior to completion of construction of the HRSGs and steam turbines (Phase 2), the combustion turbines will be operated in simple cycle mode. This capability to operate in simple cycle mode for up to 2,500 hours per year will be retained after completion of Phase 2.

Each GT will generate up to a nominal 264 MW of power, depending on the turbine option selected, at an ambient temperature of 69°F and 60% relative humidity. The hot exhaust gas from each GT will be directed to a dedicated HRSG where thermal energy will be recovered to generate steam that will be routed to either one or two steam turbines to generate additional power.

The turbines and HRSG duct burners will be fired exclusively with pipeline quality natural gas.

4.1.1 Gas Turbines

The gas turbines will be equipped with evaporative cooling, rotor air cooling finfans, and TEWAC generators.

4.1.2 Heat Recovery Steam Generators

Each HRSG will be a natural circulation-type unit designed to produce steam which will be used to drive the steam turbine. Each HRSG will be equipped with a natural gas-fired duct burner with a firing capacity up to 689 mmBtu/hr (higher heating value, HHV), depending on the turbine option. The duct burners may be fired additional hours; however, total annual firing will not exceed the equivalent of up to 3,500 hours of maximum fuel consumption capacity per duct burner, depending on the turbine option. The heat recovery surface of each unit will be finned tube, modular type for efficient, economical heat recovery and rapid field erection. In Phase 1 and in bypass mode during Phase 2, the GT exhaust will be emitted to the atmosphere through a single stack for each GT. In full combined cycle operation during Phase 2, the exhaust stream from each GT, HRSG, and duct burner will be released to the atmosphere through a single stack for each GT, HRSG and duct burner, for a total of four stacks (including the bypass stacks noted above).

4.1.3 Steam Turbine Generator(s)

The steam turbine(s) will be driven by the steam produced in the HRSGs to produce up to 616 MW of additional power, depending on the turbine option selected. The steam turbine(s) will be condensing type units and will have design throttle steam conditions of up to 1,800 psia and 1000°F, depending on the turbine option selected.

4.1.4 Inlet Air Cooling

The inlet air to each GT will be cooled during high ambient conditions through the use of evaporative coolers. Cooling of the inlet air will increase output of each GT while lowering each unit's heat rate.

4.1.5 Condenser and Cooling Tower

A condenser/cooling tower arrangement will cool steam exhausted from each steam turbine. There will be a separate condenser/cooling tower associated with each of the two trains. Each condenser will be a surface contact heat exchanger, and each cooling tower will be a multi-cell, motor-driven, mechanical draft, counterflow tower with film fill. Each cooling tower will have a 90,000 gpm circulation rate and will have a design drift rate of 0.001%.

The auxiliary cooling water system cools the plant auxiliaries such as the TEWAC generators, lube oil coolers, etc. The auxiliary cooling system uses a cross exchanger to transfer heat to the cooling tower water.

4.1.6 Auxiliary Boiler

An 80 mmBtu/hr natural gas fired Auxiliary Boiler will provide turbine fast start steam requirements during periods when the combustion turbines are out of service. The operation of the boiler will be limited to the equivalent of 4,000 hr/yr at the maximum firing rate.

4.1.7 Emissions Control

The gas turbines employ a dry low NO_x combustion system as the primary method to control emissions. The dry low NO_x system uses lean premix gas nozzle technology and multiple staged fuel nozzles to control flame temperature and promote thorough combustion during the permitted load range.

A selective catalytic reduction system (SCR) is installed at each HRSG to further reduce NO_x emissions from the turbines. A catalyst bed and an ammonia injection grid are located in a temperature region of the HRSG that will favor the reaction. The catalyst consists of a porous ceramic, honeycomb substrate that has been coated with either a vanadium-titanium or zeolite catalyst. 29.4% aqueous ammonia is injected into the flue gas upstream of the catalyst bed. The catalyst promotes a reaction between flue gas NO_x and the ammonia to convert NO_x into nitrogen and water, thereby reducing NO_x emissions. 29.4% aqueous ammonia for the SCRs will be provided from new on-site storage capacity. The tank(s) will be equipped with safety relief valves for emergency purposes; however, there will be no emissions to the atmosphere from the storage tank(s) under normal operation.

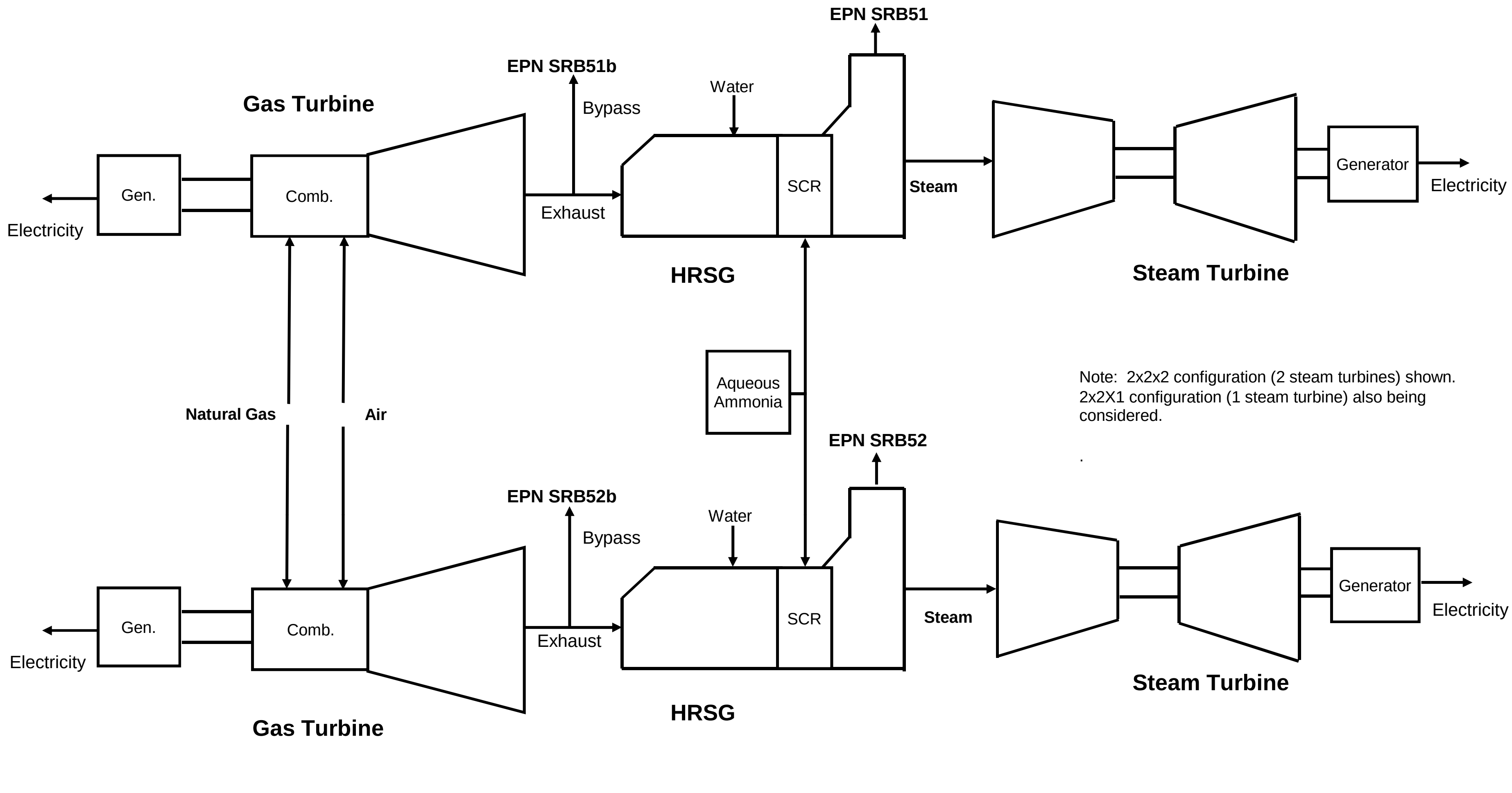


Figure 4-1
NRG Texas Power LLC
S.R. Bertron Unit 5
Process Flow Diagram
Combined Cycle Plant (2X2X2)

Section 5
Emission Rate Basis

This section contains a description of the increases in GHG emissions from new facilities associated with the project. GHG emission calculations methods are also described, and the resulting GHG emission rates are presented in Table 5-1 for each emission point. Emissions calculations are included in Appendix A.

5.1 Gas Turbines and Duct Burners

Combustion turbine and duct burner emission rates were evaluated for each of the three turbine options: GE 7FA.05, Siemens F(5), and MHI 501GAC. The turbines may be operated in combined cycle mode with or without duct firing and in simple cycle mode. Maximum fuel firing rates and thus maximum CO_2e emission rates occur during combined cycle operation with duct firing; therefore, the proposed emission limits are based on this operating mode.

Annual (tpy) emission limits, to be enforced on a 12-month rolling average basis, were calculated for each of the two generating units. Because only annual emissions limits are proposed, the emissions were based on turbine performance at average annual site conditions of 60 °F and a relative humidity of 60% for Harris County. The turbine contribution to the emissions are based on this condition at 100% load for 8,760 hour per year. The duct burner contributions to the emissions are based on the equivalent of the duct burners in each HRSG being fired at capacity for 3,500 hours for the GE and Siemens turbine options and 3,200 hours for the MHI turbine option, and unfired for the remaining hours of the year. The actual duct firing hours may exceed these hours; however, total annual duct burner heat input will not exceed the equivalent of these hours at maximum capacity.

Emissions of CO_2 were calculated by applying the 40 CFR Part 75, Appendix G, Section 2.3 emission factor of 1040 scf CO_2/mmBtu (118.9 lb/mmBtu) to the total annual firing rates of the turbines and duct burners. Emissions of CH_4 and N_2O were calculated using emission factors of 0.001 kg/mmBtu and 0.0001 kg/mmBtu, respectively, from 40 CFR Part 98, Subpart C for natural gas combustion. CO_2e emissions were calculated by multiplying the emission rate of each GHG by the global warming potential factors from the Mandatory Greenhouse Gas Reporting Rules.

During startup of the combustion turbines, emissions of GHGs are not elevated above routine levels; therefore, alternate emission rates were not calculated for these periods. Emissions during startup and shutdown periods will be counted toward total emissions in assessing compliance with the proposed annual CO_2e emission limits.

5.2 Auxiliary Boiler

The Auxiliary Boiler will be fired by natural gas. Emissions were calculated by multiplying the appropriate emission factor by the maximum annual firing, which is the equivalent of 4,000 hours per year of operation at the maximum firing capacity of 80 mmBtu/hr. Emissions of CO_2, CH_4, and N_2O were calculated using emission factors of 53.02 kg/mmBtu, 0.001 kg/mmBtu, and 0.0001 kg/mmBtu, respectively, from 40 CFR Part 98, Subpart C for natural gas combustion. The emissions rates of each GHG were then converted to CO_2e emissions using the global warming potential factors from the Mandatory Greenhouse Gas Reporting Rules.

5.3 Natural Gas Pipeline Fugitives

Fugitive emissions of CH_4 originate from the natural gas fuel lines that provide fuel to the combustion turbines and duct burners. Fugitive emission rates were estimated using the methods outlined in the *TCEQ's Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.* Each fugitive component was classified first by equipment type (valve, pump, relief valve, etc.) and then by material type (gas/vapor, light liquid, heavy liquid). Emission rates were obtained by multiplying the number of fugitive components of a particular equipment/material type by the appropriate SOCMI without ethylene emission factor and then applying appropriate control credit. No control credit was applied for the natural gas fuel lines although periodic walk through inspections of lines will be made. The methane emission rates for each compound were established by multiplying the total emission rates by the concentration (weight %) of methane in the natural gas. The CH_4 emissions rates were then converted to CO_2e emissions using the global warming potential factor from the Mandatory Greenhouse Gas Reporting Rules.

5.4 SF_6 Emissions from Electrical Equipment Insulation

Emissions of sulfur hexafluoride (SF_6) due to leaks from the insulation used in new circuit breakers were estimated by applying a 0.5% annual leak rate to the weight of SF_6 estimated to be present in circuit breakers associated with the new facilities.

Table 5-1 Proposed GHG Emission Limits (CO_2e)

EPN	Turbine Option	Description	tpy
SRB51	GE 7FA.05	SRB Unit 5 Turbine/HRSG 1	1,203,838
SRB52	GE 7FA.05	SRB Unit 5 Turbine/HRSG 2	1,203,838
SRB51	Siemens F(5)	SRB Unit 5 Turbine/HRSG 1	1,344,347
SRB52	Siemens F(5)	SRB Unit 5 Turbine/HRSG 2	1,344,347
SRB51	MHI 501GAC	SRB Unit 5 Turbine/HRSG 1	1,468,007
SRB52	MHI 501GAC	SRB Unit 5 Turbine/HRSG 2	1,468,007
AUX-BLR	ALL	Auxiliary Boiler	18,720
FUG-NGAS	ALL	Natural Gas Pipeline Fugitives	394
INS-SF6	ALL	Circuit Breaker Insulation (SF_6) Leaks	18

Section 6
Best Available Control Technology

PSD regulations require that the best available control technology (BACT) be applied to each new and modified facility that emits an air pollutant for which a significant net emissions increase will occur from the source. The only PSD pollutant addressed in this permit application is GHG. The new facilities associated with the project that emit GHGs include two natural gas fired combustion turbines and associated duct burners, a natural gas fired auxiliary boiler, and natural gas pipeline fugtives. This BACT analysis addresses these emission sources.

The U.S. EPA-preferred methodology for a BACT analysis for pollutants and facilities subject to PSD review is described in a 1987 EPA memo (U.S. EPA, Office of Air and Radiation Memorandum from J.C. Potter to the Regional Administrators, December 1, 1987). This methodology is to determine, for the emission source in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. In addition, a control technology must be analyzed only if the applicant opposes that level of control.

In an October 1990 draft guidance document (*New Source Review Workshop Manual (Draft*), October 1990), EPA set out a 5-step process for conducting a top-down BACT review, as follows:

1) Identification of available control technologies;

2) Technically infeasible alternatives are eliminated from consideration;

3) Remaining control technologies are ranked by control effectiveness;

4) Evaluation of control technologies for cost-effectiveness, energy impacts, and environmental effects in order of most effective control option to least effective; and

5) Selection of BACT.

In its *PSD and Title V Permitting Guidance for Greenhouse Gases* (November 2010), EPA reiterates that this is also the recommended process for permitting of GHG emissions under the PSD program. As such, this BACT analysis follows the top-down approach.

6.1 Combustion Turbines and Duct Burners

6.1.1 Step 1 – Identification of Potential Control Technologies

The proposed combustion turbines and duct burners will produce CO_2 emissions from the combustion of methane and other minor hydrocarbon constituents in the natural gas. Small quantities of CH_4 and N_2O will also be emitted based on emission factors required for use in the Mandatory Greenhouse Gas Reporting Rules. A RACT/BACT/LAER Clearinginghouse (RBLC) database search of CO_2 and CO_2e emissions from large natural gas fired combustion turbines was conducted to identify potential controls and performance standards. No comparable units were identified in the search. Four turbines, all much smaller than the proposed turbines were found, and no performance standards were included in the database. Emission controls were listed as good combustion practices and use of natural gas fuel for all four turbines. Due to the absence of usable information, the results of the search are not included in this permit application. Potenitally applicable control technologies were identified for the analysis based on process knowledge, previous permit applications for similar facilities, and EPA guidance.

The proposed Unit 5 electric generating facilities will be designed and constructed with the intent to operate in both simple cycle and combined cycle mode. Combined cycle power plants are the most efficient means of generating electric power from the combustion of natural gas, and combustion of natural gas has the lowest GHG emission factor of all available fossil fuels. Thus the proposed plant design results in the lowest possible GHG emission rate per kwh of electricy generated of all available fossil fuel fired electric generation technologies, prior to consideration of add-on technologies to capture and dispose of the produced CO_2. In a simple cycle configuration, the hot combustion gases exiting the combustion turbine are exhausted to the atmosphere as “wasted” heat. In a combined cycle configuration, these same hot gases are routed through an HRSG to produce steam that is then used to generate additional electricity in a steam turbine; thus, significantly increasing the thermal efficiency of the process. Additional natural gas is commonly burned in duct burners in the HRSG to allow additional steam to be produced for power production by the steam turbine. The proposed Unit 5 configuration will include duct firing capability. NRG is also requesting authorization to operate the proposed turbines in simple cycle mode by bypassing the HRSGs. Although this operating mode is less efficient, if baseload demand is less than anticipated, and the units do not operate continuously, the turbines would still be available to meet peak power demands that occur for brief periods. Frequent startup and shutdown of a combined cycle plant for peaking purposes is not an efficient mode of operation.

Although the combined cycle configuration is inherently efficient, design and operating practices can further improve and maintain that efficiency, and these practices are considered in this BACT analysis. Based on process and engineering knowledge and judgment and permit applications that have been submitted to EPA Region 6 for similar facilities, the following potentially applicable GHG control technologies were identified for consideration:

- **Periodic Maintenance and Tune-up** – Periodic tune-up of the turbines helps to maintain optimal thermal efficiency. After several months of continuous operation of the combustion turbines, fouling and degradation results in a loss of thermal efficiency. A periodic maintenance program consisting of inspection of key equipment components and tune up of the combustor will restore performance to near original conditions. The manufacturer of the proposed turbines has an extensive inspection and maintenance program that NRG Texas can implement.

- **Turbine Design** – Good turbine design maximizes thermal efficiency. Combustion turbines operate at high temperatures. Heat radiated by the hot turbine components is lost to the surrounding atmosphere. To minimize this heat loss, turbines can be wrapped with insulating blankets such that more of the heat is retained in the hot gases allowing it to be recovered as useful energy.

- **Instrumentation and Controls** – Proper instrumentation ensures efficient turbine operation to minimize fuel consumption and resulting GHG emissions. Today's F-Class turbines like those being considered for this project come from the manufacturer with a digital control package included. These systems control turbine operation, including fuel and air flow, to optimize combustion for control of criteria pollutant emissions (NO_x and CO) in addition to maintaining high operating efficiency to minimize fuel usage over the full range of operating conditions and loads.

- **Waste Heat Recovery** – As previously discussed, in a combined cycle configuration, a heat recovery steam generator (HRSG) is used to recover what would otherwise be waste heat lost to the atmosphere in the hot turbine exhaust. Use of heat recovery from the turbine exhaust to produce steam to power a steam turbine which generates additional electric power is the single most effective means of increasing the efficiency of combustion turbines used for electric power generation. The overall efficiency can be increased from about 30% for a simple cycle (no heat recovery) unit to about 50% for a combined cycle unit. In applications where process heat is needed, the steam produced in the HRSG can also be used to provide heat to plant processes in addition to or instead of being used to produce additional electricity. This "cogeneration" technology is not applicable to electric power generation unless there is a co-located steam host.

- **HRSG Design** – Efficient design of the HRSG improves overall thermal efficiency. this includes the following: finned tube, modular type heat recovery surfaces for efficient, economical heat recovery; use of an economizer, which is a heat exchanger that recovers heat from the exhaust gas to preheat incoming HRSG boiler feedwater to attain industry standard performance (IMO) for thermal efficiency; use of a heat exchanger to recover heat from HRSG blowdown to preheat feedwater; use of hot condensate as feedwater which results in less heat required to produce steam in the HRSG, thus improving thermal efficiency; and application of insulation to HRSG surfaces and steam and water lines to miminize heat loss from radiation.

- **Minimizing Fouling of Heat Exchanger Surfaces** – Fouling of interior and exterior surfaces of the heat exchanger tubes hinders the transfer of heat from the hot combustion gases to the boiler feedwater. This fouling occurs from contaminants in the turbine inlet air and in the feedwater. Fouling is minimized by inlet air filtration, maintaining proper feed water chemisty, and periodic maintenance consisting of cleaning of the tube surfaces during equipment outages.

- **Fuel Heating** – Thermal efficiency of the turbines can be increased by pre-heating the fuel prior to combustion. This is usually accomplished by heat exchange with hot water from the HRSG.

- **Multiple Trains** – Combustion turbine efficiency is highest at full load. As power demand drops, power production must be cut back. This can be accomplished by reducing duct burner firing to reduce power output of the steam turbine, reducing turbine output, and/or shutting down the unit completely. Use of multiple turbine/HRSG trains allows one or more trains to be shut down while maintaining the remaining unit(s) at or near full load where maximum efficiency is achieved rather than operating a single unit at lower less efficient loads.

- **CO_2 Capture and Storage** – Capture and compression, transport, and geologic storage of the CO_2 is a post-combustion technology that is not considered commercially viable at this time for natural gas combustion sources. However, based on requests by EPA Region 6 for other GHG permit applications, Carbon capture and sequestration (CCS) is evaluated further in this analysis.

- **Use of Low Carbon Fuel (other than natural gas)** – Natural gas is the lowest carbon fossil fuel that exists. Fuels gases, that contain significant amounts of hydrogen, which produces no CO_2 when burned, can be burned in turbines and duct burners if available and is an effective means of reducing GHG emissions in such situations.

6.1.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered “technically” feasible for the proposed turbines. NRG successfully uses all of these efficiency and control measures, with the exception of CO_2 capture and storage and use of low carbon fuel, on similar combined cycle facilities at other existing electric generating stations; thus, they are considered viable for the proposed facilities.

NRG is currently in the process of permitting a CCS demonstration project (supported by federal grant funds) to be applied to a slip stream from the exhaust from one of it's coal fired generating units at another station in Texas. However, CCS is not considered to be a viable alternative for controlling GHG emissions from natural gas fired facilities at the current time. This conclusion is supported by the BACT example for a natural gas fired boiler in Appendix F of EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (November 2010). In the EPA example, CCS is not even identified as an available control option for natural gas fired facilities. Also, on pages 33 and 44 of the Guidance Document, it states:

> "For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is available for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs."

Another CCS project that EPA Region 6 has requested be addressed in GHG BACT analyes is the Indiana Gasification Project. This project differs from the NRG Texas Bertron Unit 5 Project in several significant ways. The Indiana project will gasify coal, with the primary product being substitute natural gas (SNG), or methane. When coal is gasified, the product is a mixture consisting primarily of CO, CO_2, and H_2. A series of reactions is then used to convert the CO and H_2 to methane. To meet pipeline specifications, the CO_2 must be removed from the SNG, which produces a relatively pure CO_2 stream that is inherently ready for sequestration. Combustion of natural gas in the propsed facilites, produces an exhaust stream that is less than 5% CO_2, which is far from pure CO_2. Thus, while the Indiana Gasification Project will produce a CO_2 byproduct that is amenable to sequestration or use in enhanced oil recovery without significant further processing, the S.R. Bertron turbines will not. Separation (purification) of the CO_2 from the turbine combustion exhaust streams requires additional costly steps not otherwise necessary to the process. As a final point, the viability of the Indiana Gasification Project is highly dependent on a 30-year contract requiring the State of Indiana to purchase the SNG produced and federal loan guarantees should the plant fail. In contrast, the proposed Bertron Unit 5 project relies on market conditions for viability and is not guaranteed by the government.

The CO_2 streams included in this permit application are similar in nature to the gas-fired industrial boiler in the EPA Guidance Appendix F example, which are dilute streams, and thus are not among the facility types for which the EPA guidance states CCS should be listed in Step 1. The inference from the above citation is that for other types of facilities, CCS does not need to be listed as an available option in Step 1. However, to satify EPA Region 6 requests, NRG Texas has assumed that CCS is a viable control option in the remainder of this BACT analysis.

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Fuels used in industrial process and power generation typically include coal, fuel oil, natural gas, and process fuel gas. Of these, natural gas is typically the lowest carbon fuel that can be burned, with a CO_2 emission factor in lb/MMBtu about 55% of that of subbituminous coal. Process fuel gas is a byproduct of chemical processes, that typically contains a higher fraction of longer chain carbon compounds than natural gas and thus results in more CO_2 emissions. Table C-2 in 40 CFR Part 98 Subpart C, which contains CO_2 emission factors for a variety of fuels, gives a CO_2 factor of 59 kg/MMBtu for fuel gas compared to 53.02 kg/MMBtu for natural gas. Of over 50 fuels identified in Table C-2, coke oven gas, with a CO_2 factor of 46.85 kg/MMBtu, is the only fuel with a lower CO_2 factor than natural gas, and is not an available fuel for the proposed project. Use of a completely carbon-free fuel such as 100% hydrogen, has the potential of reducing CO_2 emissions by up to 100%. Hydrogen fuel, in any concentration, is not a readily available fuel for most electric generating facilities and is only a viable low carbon fuel at industrial plants that generate hydrogen internally. Hydrogen is not produced at the Bertron station and is not an available fuel for the proposed turbines. Natural gas is the lowest carbon fuel available for use in the proposed facilities; thus, use of low carbon fuel other than natural gas was eliminated due to lack of availability for the proposed facilities.

6.1.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies that were considered for controlling GHG emissions from the proposed turbines in order of most effective to least effective include:

- CO_2 capture and storage,
- Waste heat recovery,
- Instrumentation and control system,
- Turbine design,
- HRSG design,
- Minimizing fouling of turbine/HRSG,

- Fuel pre-heating,
- Multiple turbine/HRSG trains, and
- Periodic maintenance and tune-ups.

CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus is considered to be the most effective control method.

Exhaust waste heat recovery can take several forms, and use of an HRSG with a steam turbine can increase thermal efficiency from around 30% for a simple cycle unit to about 50%, which is equivalent to about a 40% reduction in CO_2e emissions.

An instrumentation and control package to continuously monitoring of the turbine package ensures the turbine is operating in the most efficient manner. Instrumentation and controls include:

- Gas flow rate monitoring,
- Fuel gas flow and usage,
- Exhaust gas temperature monitoring,
- Pressure monitoring around the turbine package,
- Temperature monitoring around the turbine package,
- Vibration monitoring,
- Air/fuel ratio monitoring, and
- HRSG Unit temperature and pressure monitoring.

At similar NRG Texas facilities, periodic maintenance and tune-ups of existing turbines are performed per the manufacturer's recommended program. These programs consist of thorough inspection and maintenance of all turbine components on a daily, monthly, semi-annual, or annual frequency depending on the parameter or component and as recommended by the turbine vendor.

The effectiveness of instrumentation and control, maintenance and tune-ups, and the remaining efficiency improvement options cannot be quantitatively estimated, but are each generally in the <1% to 3% range, but any attempt to rank them in order of effectiveness would not be meaningful.

6.1.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

A brief evaluation of each technically feasible combustion turbine control option follows.

CCS. The technology to capture and store CO_2 in permanent underground storage facilities exists and has been used in limited applications, but as stated previously, is not economically viable for most commercial applications. However, since the technology has been demonstrated on some processes and is potentially feasible for the proposed turbines, it cannot be completely ruled out based only on technical infeasibility; therefore, a cost effective analysis was performed for this option. The results of the analysis, presented in Tables 6-1 and 6-2, show that the cost of CCS for the project would be approximately $107 per ton of CO_2 controlled, which is not considered to be cost effective for GHG control. This equates to a total cost of about $283,000,000 per year the two turbine/HRSG trains. The estimated total capital cost of the proposed project is $700,000,000. Based on a 7% interest rate, and 20 year equipment life, this cost equates to an annualized cost of about $66,000,000 for the project alone. Thus, the annualized cost of CCS would be about four times the cost of the project without CCS. An additional cost of this magnitude would make the project economically unviable; therefore, CCS was rejected as a control option on the basis of excessive cost.

There are additional negative impacts associated with use of CCS. The additional process equipment required to separate, cool, and compress the CO_2 would require a significant additional power and energy expenditure. This equipment would include amine units, cryogenic units, dehydration units, and compression facilities. The power and energy must be provided from additional combustion units, and/or increase the parasitic load on the proposed facilities which significantly reduces the net heat rate (efficieny) of the plant. Significant additional GHG emissions, as well as additional criteria pollutant (NO_x, CO, VOC, PM, SO_2) emissions, would occur per MW of net electricity produced.

Based on both the excessive cost effectiveness in $/ton of GHG emissions controlled and the inability of the project to bear the high cost and the associated negative environmental and energy impacts, CCS is rejected as a control option for the proposed project.

Instrumentation and Controls. Instrumentation and controls that can be applied to the combustion turbines/HRSGs are identified in Section 6.1.3 and are considered an effective means of control for the proposed turbine configuration.

Waste Heat Recovery. Heat recovery systems consisting of an HRSG with steam turbine and other practices and design features identified in Section 6.1.1, that are designed to recover and utilize the waste heat in the turbine/HRSG trains, are capable of effectively reducing GHG emissions by about 40% compared to a combustion turbine alone that exhausts to the atmosphere without any form of exhaust heat recovery.

Periodic Maintenance and Tune-ups. Periodic maintenance and tune-ups of the turbines include:

- Preventive maintenance check of fuel gas flow meters annually,
- Cleaning of combustors on an as-needed basis, and
- Implementation of manufacturer's recommended inspection and maintenance program.

These and the remaining options listed below insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement.

- Turbine design,
- HRSG design,
- Minimizing fouling of turbine/HRSG,
- Fuel pre-heating, and
- Multiple turbine/HRSG trains.

6.1.5 Step 5 – Selection of BACT

As previously stated, all of the applicable combustion turbine/HRSG design, waste heat recovery, plant design, and maintenance and tune-up options that increase overall efficiency by reducing the net plant hea are are currently utilized on existing turbines at other NRG Texas as they are good business practices and effective means of minimizing all air pollutants in addition to minimizing GHG emissions. Thus, all identified control practices other than CCS, are also included in the design of the new turbines and are thus part of the selected BACT. The following additional BACT practices are proposed for the turbines:

- Install two turbine/HRSG trains to allow shutdown of one unit during periods of low demand to minimize operation at less efficient reduced loads,
- Determine CO_2e emissions from the turbines based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance,
- Good turbine design to maximize efficiency,

- Install and operate efficiently designed HRSGs and steam turbines during baseload operation of the turbines,
- Design HRSGs to recover heat from exhaust and blowdown for pre-heating of fuel and boiler feedwater,
- Install instrumentation and control package including:
    - o Gas flow rate monitoring,
    - o Fuel gas flow and usage,
    - o Exhaust gas temperature monitoring,
    - o Pressure monitoring around the turbine package,
    - o Temperature monitoring around the turbine package,
    - o Vibration monitoring,
    - o Air/fuel ratio monitoring, and
    - o HRSG temperature and pressure monitoring.
- Implement vendor's recommended comprehensive inspection and maintenance program for the turbines,
- Clean turbine combustors and HRSG heat transfer surfaces as needed,
- Calibrate and perform preventive maintenance on the fuel flow meter once per year, and
- Maintain minimum efficiency standards expressed as heat rate (Btu/kwh, HHV) on a 12-month rolling average basis for each turbine/HRSG operating mode. Proposed standards are presented in Table 6-3 for each turbine option and operating mode.

Determination of Proposed Efficiency Standards. As previously stated, an RBLC database search did not yield any useful information for either identifying control technologies or establishing BACT performance limits for GHG emissions from turbines/HRSGs. However, EPA Region 6 has issued one GHG PSD permit for a similar combined cycle facility to LCRA (Thomas Ferguson Plant) in November 2011, and is currently reviewing two additional permit applications for similar Calpine facilities (Channel Energy Center and Deer Park Energy Center). A Btu/kwh performance standard was proposed or established for each of these projects, all of which are located in Texas. Btu/kwh performance standards for three additional similar facilities permitted elsewhere in the United States were also identified. Table 6-4 presents a comparison of the performance standards for these facilities with those proposed for the S.R. Bertron Unit 5 turbines/HRSGs combined cycle operating mode.

The Palmdale Hybrid Power Project, located in California, is a combined cycle plant that is integrated with a solar-thermal plant which contributes heat energy to the steam turbine. This different configuration and technology makes the standard for this plant not directly comparable to the remaining plants, including the proposed facility. This plant has a heat rate standard of 7,319 Btu/kwh. If the Palmdale Project is excluded from consideration, the heat rate standards for the remaining plants range from 7,525 Btu/kwh to 7,730 Btu/kwh. NRG Texas is proposing a heat rate standard of 7,730 Btu/kwh, HHV, based on net plant power output in combined cycle mode without duct firing. A standard of 11,500 Btu/kwh is proposed for simple cycle operation. The derivation of the proposed heat rate standards is presented in Table 6-3 and described below.

The turbine manufacturer's design heat rates were first adjusted by adding following margins:

- 3.3% added for variations between as built and design conditions, including periods of operation at part load conditions,
- 6.0% for efficiency loss due to equipment degradation, and
- 3.0% for variations in operation of ancillary plant facilities.

These margins were used by Calpine in recently submitted GHG permit applications for two proposed facilities in Texas (see Table 6-4) to arrive at a proposed heat rate of 7,730 Btu/kwh, which was subsequently used by EPA as the performance standard in each of the draft GHG permits. NRG then compared the adjusted heat rates for the proposed turbines to the proposed standard for the Calpine turbines and concluded the differences were not significant after taking the adjustment margins into consideration. Therefore, for BACT consistency purposes, NRG proposes the same 7,730 Btu/kwh efficiency standard for the Bertron Unit 5 turbines.

6.2 Auxiliary Boiler

6.2.1 Step 1 – Identification of Potential Control Technologies

The potentially applicable technologies to minimize GHG emissions from the auxiliary boiler include the following:

- **Periodic Tune-up** – Periodically tune-up of the boilers to maintain optimal thermal efficiency.
- **Boiler Design** – Good boiler design to maximize thermal efficiency,
- **Automated Boiler Air/Fuel Control** – Monitoring of oxygen concentration in the flue gas to be used to control air to fuel ratio on a continuous basis for optimal efficiency.
- **Waste Heat Recovery** – use of heat exchangers to recover waste heat from the boiler exhaust.

- **Use of Low Carbon Fuels (other than natural gas)** – Fuels vary in the amount of carbon per btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions.

- **CO_2 Capture and Storage** – Capture and compression, transport, and geologic storage of the CO_2.

6.2.2 Step 2 – Elimination of Technically Infeasible Alternatives

The proposed boiler is small (80 MMBtu/hr) and will only be operated up to 4,000 hours year each. As a result, the boiler will emit less than 19,000 tpy of CO_2e, which is about 0.2% of the total project CO_2e emissions. Waste heat recovery is not applicable to intermittently operated combustion units, and is therefore rejected for the boiler. As discussed in Section 6.1.2, low carbon fuels other than natural gas are not available at the Bertron station; therefore, this option is not considered feasible for the boiler.

Carbon capture and storage is also not a practical or economically feasible add-on option for very small intermittent sources, and was also eliminated.

Automated air/fuel controls would not result in any appreciable increase in boiler efficiency or resulting GHG emission reduction due to the intermittent operation and already insignificant amount of GHG emissions from the boiler, and was therefore also rejected as a viable control option.

The remaining control options identified in Step 1 have a minor degree of applicability and have therefore been retained for further consideration, although the potential for any significant emission reduction does not exist due to the already low emission rates.

6.2.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies applicable to the proposed boiler design in order of most effective to least effective include:

- Boiler Design (up to 10%), and
- Periodic tune-up (up to 10%).

Good boiler design and periodic tune-ups have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies were obtained from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). This report addressed improvements to existing energy systems as well as new equipment; thus, the higher end of the range of stated efficiency improvements that can be realized is assumed to apply to the existing (older) facilities, with the lower end of the range being more applicable to new boiler designs.

6.2.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Boiler Design. New boilers can be designed with efficient burners and state-of-the-art refractory and insulation materials in the boiler walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. Due to the very low energy consumption of this small intermittently used boiler, only basic boiler efficiency features are practical for consideration in the boiler design.

Periodic Boiler Tune-ups. Periodic tune-ups of the boiler include:

- Preventive maintenance check of fuel gas flow meters,
- Preventive maintenance check of oxygen control analyzers,
- Cleaning of burner tips on an as-needed basis, and
- Cleaning of convection section tubes on an as-needed basis.

These activities insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5 to 1.5% range. Due to the minimal use of these boilers, regularly scheduled tune-ups and inspections are not warranted.

6.2.5 Step 5 – Selection of BACT

Efficient boiler design, use of natural gas, and tune-ups performed as needed are proposed as BACT for the boilers as detailed below.

- Use of low carbon fuel (natural gas). Natural gas will be the only fuel fired in the proposed boilers. It is the lowest carbon fuel available for use at the Bertron Station.
- Good boiler design and operation to maximize thermal efficiency and reduce heat loss to the extent practical for boilers of this size in intermittent service.
- Use of manual air/fuel controls to maximize combustion efficiency.
- Clean and inspect boiler burner tips and perform tune-ups as needed and per vendor recommendations.

6.3 Process Fugitives

Small amounts of methane emissions may occur from leaking natural gas piping components (process fugitives) associated with the proposed project. The methane emissions from processes fugitives have been conservatively estimated to be 357 tpy as CO_2e. This is a negligible (0.013%) contribution to the total GHG emissions from the project; however, for completeness, they are addressed in this BACT analysis.

6.3.1 Step 1 – Identification of Potential Control Technologies

The only identified control technology for process fugitive emissions of CO_2e is use of a leak detection and repair (LDAR) program. LDAR programs vary in stringency as needed for control of VOC emissions; however, due to the negligible amount of GHG emissions from fugitives, LDAR programs would not be considered for control of GHG emissions alone. As such, evaluating the relative effectiveness of different LDAR programs is not warranted.

6.3.2 Step 2 – Elimination of Technically Infeasible Alternatives

LDAR programs are a technically feasible option for controlling process fugitive GHG emissions.

6.3.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

As stated in Step 1, this evaluation does not compare the effectiveness of different levels of LDAR programs.

6.3.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that occur from process fugitives is clearly not cost effective due to the already insignificant level of emissions. However, a cost effectiveness analysis for a basic LDAR program to control process fugitive CH_4 emissions is presented in Table 6-5 to demonstrate this point. The analysis shows that even the least stringent LDAR program (TCEQ's 28M program) would cost $61/ton of CO_2e controlled. This cost is considered excessive for GHGs; therefore, it was rejected from further consideration.

6.3.5 Step 5 – Selection of BACT

Due to the negligible amount of GHG emissions from process fugitives, the only available control, implementation of an LDAR program, is clearly not cost effective and would result in no significant reduction in overall project GHG emissions regardless of cost. Based on these considerations, BACT is determined to be normal plant maintenance practices as needed to for safety and reliability purposes.

6.4 SF_6 Emissions from Electrical Equipment Insulation

Emissions of sulfur hexafluoride (SF_6) due to leaks from the insulation used in new circuit breakers are estimated to be less than 2 lb/yr of actual mass emissions and less than 18 tpy of CO_2e. These emissions are negligible, and consideration of emissions controls for BACT purposes is not warranted. However, for completeness, they have been included in the BACT analysis. There are two methods for reducing or eliminating SF_6 emissions: 1) replace SF_6 with another insulation material, and 2) design the insulation systems to minimize SF_6 leaks.

SF_6 is a proven material for the proposed application and is considered to be a superior insulating material to alternatives currently available. Because even complete elimination of the emissions would result in no quantifiable benefit with respect to global warming potential, replacing it with an inferior alternative is not considered to be a prudent option and was eliminated from further consideration.

Modern high voltage circuit breakers are designed with totally enclosed insulation systems that result in minimal SF_6 leak potential. Alarm systems that can detect when a portion of the SF_6 has been lost from the system are available to identify leaks for repair before further losses occur. Although such systems would not necessarily be considerd cost effective when expressed in traditional BACT $/ton of emissions avoided terms, their cost relative to the project cost is not prohibitive.

NRG proposes to use circuit breakers with totally enclosed insulation systems equipped with a low pressure alarm and low pressure lockout. The lockout will prevent operation of the circuit breaker if insufficient SF_6 remains in the system.

Table 6-1 Cost Analysis for Post-Combustion CCS for Turbines/HRSGs

CCS System Component	Cost ($/ton of CO_2 Controlled)[1]	Tons of CO_2 Controlled per Year[2]	Total Annualized Cost
CO_2 Capture and Compression Facilities	$103	2,642,412	$272,168,470
CO_2 Transport Facilities (Table 6-2)	$3.61	2,642,412	$9,542,251
CO_2 Storage Facilities	$0.51	2,642,412	$1,347,630
Total CCS System Cost	$107	2,642,412	$283,058,351

Proposed Plant Cost	Total Capital Cost	Capital Recovery Factor[4]	Annualized Capital Cost
Cost of Proposed Units w/o CCS[5]	$700,000,000	0.0944	$66,075,048

1. Costs are from *Report of the Interagency Task Force on Carbon Capture (August, 2010)*. A range of costs was provided for transport and storage facilities; for conservatism, the low ends of these ranges were used in this analysis as they contribute little to the total cost. Reported costs in $/tonne were converted to $/ton.

2. Tons of CO_2 controlled assumes 90% capture of all CO_2 emissions from the two turbines and duct burners.

4. Capital recovery factor based on 7% interest rate and 20 year equipment life.

Interest rate	7%
Equipent Life (yrs)	20

Table 6-2 CO_2 Pipeline Construction Cost Estimate

Description	Cost	Basis
Capital Cost:		
AGI Pipeline - 36" Diameter	$28,000,000	10-mile pipeline 36-inch diameter (10 miles is location of nearest storage cavern). DOE/NETL calculation method (see below).
Total Capital Cost for CO2 Compression, Pipeline, and Well	**$28,000,000**	
Capital Recovery Factor[1]	0.0944	7% interest rate and 20 year equipment life
Annualized Capital Cost ($/yr)	**$2,643,002**	Total capital cost times capital recovery factor
Operating Cost:		
Power Cost, $/year	$4,899,249	10000 hp electric compressor and $0.075/kwh electricity cost
O&M Cost, $/year	$2,000,000	O&M estimate
Total Annual Operating Cost ($/yr)	**$6,899,249**	
Total Cost:		
Total Annual Cost ($/yr)	**$9,542,251**	Annualized capital cost plus annual operating cost
GHG Emissions Controlled (ton/yr)	2,642,412	From GHG Calculations in Appendix A
Cost Effectiveness ($/ton)	**$3.61**	Total Annual Cost/GHG Emissions Controlled

1. Capital recovery factor based on 7% interest rate and 20 year equipment life.

Interest rate:	7%
Equipent Life (yrs):	20

Capital Cost for Construction of CO2 Pipeline to Nearest Storage Cavern:

Length in miles (L): 10
Diameter in inches (D): 36

Several candidate storage reservoirs exist within 10 to 50 miles of the proposed project; however, none of these have been confirmed to be viable for large scale CO2 storage at this time. However, it was assumed for this analysis that a suitable storage reservoir would be available within 10 miles.

Component	**Cost**	**Cost Equation**[2]
Materials	$8,944,802	Materials = $64,632 + $1.85 x L x (330.5 x D^2 + 686.7 x D + 26,960)
Labor	$13,096,715	Labor = $341,627 + $1.85 x L x (343.2 x D^2 + 2,074 x D + 170,013)
Miscellaneous	$5,052,053	Misc. = $150,166 + $1.58 x L x (8,417 x D + 7,234)
Right-of-Way	$654,757	Right-of-Way = $48,037 + $1.20 x L x (577 x D + 29,788)
Total Cost of Pipeline	**$27,748,327**	

2: Pipeline cost equations are from: *Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs* , National Energy Technology Laboratory, U.S. Dept. of Energy, DOE/NETL-2010/1447, March 2010

Table 6-3 Proposed Turbine/HRSG Efficiency Standards (Btu/kwh, HHV)

Turbine Option	Manufacturer's Design Heat Rate (full load, w/o duct firing @ 60°F & 60% RH)		Adjustment Factor*	Calculatated Heat Rate with Adjustment Factor	
	Combined Cycle	Simple Cycle		Combined Cycle (w/o duct firing)	Simple Cycle
GE 7FA.05	6,809	9,789	1.128	7,679	11,040
Siemens F(5)	7,001	10,239	1.128	7,896	11,548
MHI 501GAC	6,891	9,684	1.128	7,772	10,922
Proposed (all turbines)	NA	NA	NA	**7,730**	**11,500**

* Adjustment Factor includes the following:
3.3% added for variations between as built & design conditions, including periods of operation at part load,
6.0% for efficiency loss due to equipment degradation, and
3.0% for variations in operation of ancillary plant facilities.

Table 6-4 Comparision of Proposed Efficiency Standards with Other Facilities

Project	Performance Standard (Btu/kwh, HHV)	Comments
Proposed S.R. Bertron Unit 5	7,730	Combined Cylce with duct burners, GE 7FA.05 turbines
	7,730	Combined Cylce with duct burners, Siemens F(5) turbines
	7,730	Combined Cylce with duct burners, MHI 501GAC turbines
LCRA Thomas Ferguson	7,720	Combined Cylce w/o duct burners, GE 7FA turbines
Palmdale Hybrid Power Project	7,319*	Combined Cylce with duct burners, GE 7FA turbines, integrated with solar-thermal plant
Cricket Valley Energy Center	7,605	Combined Cylce w/o duct burners, GE 7FA turbines
Pioneer Valley Energy Center	~7,525, HHV (6,840, LHV)	Combined Cylce, turbine model unknown
Proposed Calpine Channel Energy Center	7,730	Combined Cylce with duct burners, Siemens 501F turbine
Proposed Calpine Deer Park Energy Cener	7,730	Combined Cycle with duct burners, Siemens 501F turbine

* The Palmdale Hybrid Power Project is integrated with a solar energy plant that contributes thermal energy to the steam generator to produce part of the electric power. The heat rate limit is a site-wide heat rate that reflects the contribution from the solar energy collectors and thus cannot be compared directly to the heat rate limits of the other plants.

Table 6-5 Cost Analysis for Natural Gas Fugitives LDAR Program

Monitoring Cost:	$2.50	per component per quarter
Number of Valves:	140	monitored
Number of Flanges:	350	not monitored
Number of PRVs:	10	monitored
Number of Pumps:	0	monitored
Number of Comps:	0	monitored
Total Number Monitored:	150	monitored
Total Cost of Monitoring:	$1,500	per year
Number of Repairs:	72	per year (12% of monitored components per quarter)
Cost of Repairs:	$12,240	per year @ $200 per component (85% of leaking components; remaining 15% only require minor repair)
Cost to re-monitor repairs:	$180	per year
Total Cost of LDAR:	$13,920	per year (montoring + repair + re-monitor)
Emission Reduction:	10.93	tpy of methane (based on 28M reduction credits)
Emission Reduction:	229.49	tpy of CO_2e
Cost Effectiveness:	$1,274	per ton of CH_4
Cost Effectiveness:	**$61**	per ton of CO_2e

Appendix A

Emissions Calculations

A-1a Combustion Turbine/Duct Burner Emissions Calculations - GE

EPN: SRB51, SRB52 | **Turbine: GE 7FA.05**

Specifications

Parameter		Value	Unit
Fuel Type : Natural Gas			
		1,020	Btu/scf
Annual Average Firing Rate:	per Turbine	2101.20	mmBtu/hr
	per duct burner	523.10	mmBtu/hr
	Factor Basis	**Emission Factor**	
CO2 Emission Factor*	Part 75 App G	118.9	lb/mmBtu
CH4 Emission Factor	Part 98, App C	0.001	kg/mmBtu
N2O Emission Factor	Part 98, App C	0.0001	kg/mmBtu
Operating Hours	Turbines	8760	hrs/year
	Duct Burners	3500	hrs/year

Pollutant	Emission Rates (each unit) Actual tpy	CO2e Factor	CO2e tpy
CO2	1,202,678	1	1,202,678
CH4	22	21	468
N20	2	310	692
Total CO2e	NA	NA	1,203,838

Sample Calculations:

CO2 emission factor calculated from constants in Section 2.3 of Appendix G to 40 CFR Part 75 as follows:

CO2 (lb/mmBtu) = 1040 scf/mmbtu x 1 mole/385 scf x 44 lb CO2/mole = 118.9 lb/mmBtu

$$\text{Turbine CO2} = \frac{2{,}101.2\ \text{MMBtu}}{\text{hr}} \left| \frac{118.9\ \text{lb}}{\text{MMBTU}} \right| \frac{1\ \text{ton}}{2000\ \text{lb}} \left| \frac{8{,}760\ \text{hr}}{\text{yr}} \right. = 1{,}093{,}873\ \text{tpy}$$

$$\text{Turbine CH4} = \frac{2{,}101.2\ \text{MMBtu}}{\text{hr}} \left| \frac{0.001\ \text{kg}}{\text{MMBTU}} \right| \frac{2.205\ \text{lb}}{\text{kg}} \left| \frac{1\ \text{ton}}{2000\ \text{lb}} \right| \frac{8{,}760\ \text{hr}}{\text{yr}} = 20\ \text{tpy}$$

A-1b Combustion Turbine/Duct Burner Emissions Calculations - Siemens

EPN: SRB51, SRB52

Turbine: Siemens F(5)

Specifications

Parameter		Value	Unit
Fuel Type : Natural Gas			
		1,020	Btu/scf
Annual Average Firing Rate:	per Turbine	2337.60	mmBtu/hr
	per duct burner	606.30	mmBtu/hr
	Factor Basis	**Emission Factor**	
CO_2 Emission Factor	Part 75 App G	118.9	lb/mmbtu
CH_4 Emission Factor	Part 98, App C	0.001	kg/mmBtu
N_2O Emission Factor	Part 98, App C	0.0001	kg/mmBtu
Operating Hours	Turbines	8760	hrs/year
	Duct Burners	3500	hrs/year

Emission Rates (each unit)

Pollutant	Actual tpy	CO2e Factor	CO2e tpy
CO_2	1,343,052	1	1,343,052
CH_4	25	21	523
N20	2	310	772
Total CO2e	NA	NA	1,344,347

Sample Calculations:

CO_2 emission factor calculated from constants in Section 2.3 of Appendix G to 40 CFR Part 75 as follows:

CO_2 (lb/mmBtu) = 1040 scf/mmbtu x 1 mole/385 scf x 44 lb CO_2/mole = 118.9 lb/mmBtu

$$\text{Turbine } CO_2 = \frac{2{,}337.6\ \text{MMBtu}}{\text{hr}} \left| \frac{118.9\ \text{lb}}{\text{MMBTU}} \right| \frac{1\ \text{ton}}{2000\ \text{lb}} \left| \frac{8{,}760\ \text{hr}}{\text{yr}} \right. = 1{,}216{,}941\ \text{tpy}$$

$$\text{Turbine } CH_4 = \frac{2{,}337.6\ \text{MMBtu}}{\text{hr}} \left| \frac{0.001\ \text{kg}}{\text{MMBTU}} \right| \frac{2.205\ \text{lb}}{\text{kg}} \left| \frac{1\ \text{ton}}{2000\ \text{lb}} \right| \frac{8{,}760\ \text{hr}}{\text{yr}} = 23\ \text{tpy}$$

A-1c Combustion Turbine/Duct Burner Emissions Calculations - MHI

EPN: SRB51, SRB52

Turbine: MHI 501GAC

Specifications

Parameter		Value	Unit
Fuel Type : Natural Gas			
		1,020	Btu/scf
Annual Average Firing Rate:	per Turbine	2586.10	mmBtu/hr
	per duct burner	632.50	mmBtu/hr
	Factor Basis	**Emission Factor**	
CO2 Emission Factor	Part 75 App G	118.9	lb/mmbtu
CH4 Emission Factor	Part 98, App C	0.001	kg/mmBtu
N2O Emission Factor	Part 98, App C	0.0001	kg/mmBtu
Operating Hours	Turbines	8760	hrs/year
	Duct Burners	3200	hrs/year

Emission Rates (each unit)

Pollutant	Actual tpy	CO2e Factor	CO2e tpy
CO2	1,466,592	1	1,466,592
CH4	27	21	571
N20	3	310	843
Total CO2e	NA	NA	1,468,007

Sample Calculations:

CO2 emission factor calculated from constants in Section 2.3 of Appendix G to 40 CFR Part 75 as follows:

CO2 (lb/mmBtu) = 1040 scf/mmbtu x 1 mole/385 scf x 44 lb CO2/mole = 118.9 lb/mmBtu

$$\text{Turbine CO2} = \frac{2{,}586.1\ \text{MMBtu}}{\text{hr}} \cdot \frac{118.9\ \text{lb}}{\text{MMBTU}} \cdot \frac{1\ \text{ton}}{2000\ \text{lb}} \cdot \frac{8{,}760\ \text{hr}}{\text{yr}} = 1{,}346{,}309\ \text{tpy}$$

$$\text{Turbine CH4} = \frac{2{,}586.1\ \text{MMBtu}}{\text{hr}} \cdot \frac{0.001\ \text{kg}}{\text{MMBTU}} \cdot \frac{2.205\ \text{lb}}{\text{kg}} \cdot \frac{1\ \text{ton}}{2000\ \text{lb}} \cdot \frac{8{,}760\ \text{hr}}{\text{yr}} = 25\ \text{tpy}$$

A-2 Auxiliary Boiler Emissions

EPN: AUX-BLR

Specifications

Parameter		**Value**	**Unit**
Fuel Type : Natural Gas			
		1,020	Btu/scf
Maximum Firing Rate		80.00	mmBtu/hr
	Factor Basis	**Emission Factor**	
CO2 Emission Factor	Part 98, App C	53.02	kg/mmBtu
CH4 Emission Factor	Part 98, App C	0.001	kg/mmBtu
N2O Emission Factor	Part 98, App C	0.0001	kg/mmBtu
Operating Hours		4000	hrs/year

Emission Rates

Pollutant	**Actual tpy**	**CO2e Factor**	**CO2e tpy**
CO2	18,702	1	18,702
CH4	0.353	21	7.41
N20	0.035	310	10.93
Total CO2e	NA	NA	18,720

Sample Calculations:

Annual CO2 =	80.0 mmBtu	53 kg	2.205 lb	1 ton	4,000 hr	=	18,702 tpy
	hr	mmBTU	kg	2000 lb	yr		

A-3 Natural Gas Fugitive Emission Calculations

EPN: FUG-NGAS

Component Type	Stream Type	Emission Factor SOCMI without Ethylene	Number of Components	Annual Emissions (tpy)
Valves	Gas/Vapor	0.0089	140	5.4575
	Light Liquid	0.0035	0	0.0000
	Heavy Liquid	0.0007	0	0.0000
Pumps	Light Liquid	0.0386	0	0.0000
	Heavy Liquid	0.0161	0	0.0000
Flanges	Gas/Vapor	0.0029	350	4.4457
	Light Liquid	0.0005	0	0.0000
	Heavy Liquid	0.00007	0	0.0000
Compressors	Gas/Vapor	0.5027	0	0.0000
Relief Valves	Gas/Vapor	0.2293	10	10.0433
Open Ends		0.004	0	0.0000
Sample Con.		0.033	0	0.0000
Other	Gas/Vapor	0	0	0.0000
	Lt/Hvy Liquid	0	0	0.0000
Process Drains		0.07	0	0.0000
Operating Hours:	8,760	**Total**	**500**	**19.95**
			% CH4	94%
			CH4 tpy	**18.75**
			Global warming potential factor	21
			CO2e tpy	**394**

A-4 SF_6 Emission Calculations for Electrical Equipment Insulation Leaks

EPN: INS-SF6

Emissions of from leaks of SF_6 gas used to insulate circuit breakers used in proposed plant.

Estimated quantity of SF_6 in new equipment:	300	lb
Annual Leak Rate:	0.50%	of quantity present
Annual Emission Rate:	1.5	lb/yr
=	0.00075	tpy of SF6
Global Warming Potential Factor for SF_6:	23,900	
Annual Emission Rate (CO2 Equivalent):	**17.9**	**tpy of CO_2e**