eSPARC
Consolidated Asset Management Services

1110 NASA Parkway, Suite 212
Houston, TX 77058
(P) 281-333-3339
(F) 281-333-3386

November 07, 2013

Mr. Jeffrey Robinson
Permit Section Chief
US Environmental Protection Agency (6PD-R)
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202
R6AirPermits@epa.gov
robinson.jeffrey@epa.gov

RE: Application for PSD Air Quality Permit for Green House Gas Emissions
Lon C. Hill Power Station
Corpus Christi, Nueces County
CN602656688; RN100215979

Dear Mr. Robinson,

On behalf of Lon C. Hill, LP (LCH), CAMS eSPARC is submitting this application for a Prevention of Significant Deterioration (PSD) Air Quality Permit for Greenhouse Gas (GHG) emissions from the redevelopment of Lon C Hill Power Station.

The Lon C. Hill Power Station ceased operations in late 2002. In 2008, a Standard Permit was issued for the repowering of the facility with a combined cycle unit. However, construction of the new unit never commenced. On November 4, 2011 New Source Review construction authorization for the new unit expired and both the NSR and Title V air permits were subsequently voided.

LCH is now proposing to construct and operate a new 2x1 combined cycle power station as represented in the enclosed application. A PSD permit application for other regulated pollutants is being submitted to TCEQ simultaneously.

LCH and CAMS eSPARC are committed to working with US EPA to ensure a timely review of this application. We are available to meet with you at your convenience in your offices to discuss the project and answer any questions you may have.

Pease contact me at (281) 333-3339 x201 or via email at mjohnson@camsesparc.com, if you have any questions or need additional information.

Sincerely,

Mona Caesar Johnson, P.E.
CAMS eSPARC, LLC
Texas Registered Engineering Firm F-15310

CC: CAMS: Mr. Gary Clark (GClark@camstex.com)
Mr. Matt Lindsey (mlindsey@camstex.com)

TCEQ Air Permits Division

TCEQ Region 14

Lon C. Hill Power Station
Prevention of Significant Deterioration
Air Permit Application for Greenhouse Gases

Submitted to
Environmental Protection Agency
Region 6
Multimedia Planning and Permitting Division

Submitted by
Lon C. Hill, LP
Houston, Texas 77002

Prepared by
CAMS eSPARC, LLC
1110 NASA Parkway, Suite 212
Houston, TX 77058

November 2013

Lon C. Hill Power Station
Prevention of Significant Deterioration
Air Permit Application for Greenhouse Gases

Table of Contents

Attachments

List of Tables

List of Figures

Section 1
Administrative Information Forms

This section includes the required Administrative Information Form. Federal New Source Review (FNSR) applicability forms (TCEQ Tables 1F, 2F and 3F) are provided in Attachment A.

This application addresses only GHG emissions. The PSD permit application which addresses the other regulated pollutants is being reviewed by TCEQ. Since the project will be major for other PSD pollutants and the proposed CO_2e emission rate will exceed 75,000 tpy of CO_2e, PSD review of GHG emissions is required for the proposed project.

Administrative Information Form

A. Company or Other Legal Name: Lon C. Hill, LP		
B. Company Official Contact Name (☒ Mr. ☐Mrs. ☐Ms. ☐Dr.): Mr. Gary Clark		
Title: Asset Manager		
Mailing Address: 919 Milam St., Suite 2300		
City: Houston	State: TX	ZIP Code:77002
Telephone No.: (713) 358-9768	Fax No.: (361) 575-4978	E-mail Address: gclark@camstex.com
C. Technical Contact Name: Mr. Matthew Lindsey		
Title: Sr. EHS Specialist		
Company Name: Consolidated Asset Management Services		
Mailing Address: 919 Milam, Suite 2300		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: (713) 358-9734	Fax No.: (713) 358-9730	E-mail Address: mlindsey@camstex.com
D. Facility Location Information:		
Street Address: 3501 Callicoatte Rd		
If no street address, provide clear driving directions to the site in writing:		
City: Corpus Christi	County: Nueces	ZIP Code: 78410
E. TCEQ Account Identification Number (leave blank if new site or facility):		
F. TCEQ Customer Reference Number *(leave blank if unknown)*: CN602656688		
G. TCEQ Regulated Entity Number *(leave blank if unknown)*: RN100215979		
H. Site Name: Lon C. Hill Power 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 Electric Services		
L. Projected Start of Construction Date: May 1, 2015	Projected Start of Operation Date: April 1, 2017	
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. Gary Clark, Asset Manager		
SIGNATURE: [signature] *Original Signature Required*		
DATE: 11/07/2013		

Section 2
Project Overview

Lon C. Hill, LP (LCH) is proposing to construct, own and operate a new 2x1 combined cycle power plant west of Corpus Christi, Nueces County, TX, which will be referred to as the Lon C. Hill Power Station. The new plant nominal capacity will be of approximately 625 to 740 megawatts (MW). Construction of the new plant is proposed to begin in May 2015 with commercial operation proposed for April 2017.

The site previously hosted a four unit generation facility that ceased operations in 2002 and was subsequently demolished down to the equipment foundations. All associated air permits (New Source Review Permits and Federal Operating Permits) were voided.

The proposed new facility will consist of two natural gas-fired combustion turbines (GTs), two heat recovery steam generators (HRSGs) with natural gas-fired duct burners and one steam turbine (ST) generator (2x1 configuration). Proposed ancillary equipment may include a natural gas fuel supply system, an auxiliary natural gas-fired boiler, a diesel-fired emergency generator, a fire protection system, an water-cooled condenser with a cooling tower, an oil/water separator, a degreaser, two diesel storage tanks, an aqueous ammonia storage tank, and storage and dispensing of gasoline from a small gasoline storage tank. Other equipment may include an evaporative cooling system or gas turbine inlet chilling and chilled water storage.

The combined cycle units will exclusively fire natural gas. Dry low-NOx (DLN) combustors will be used to reduce the nitrogen oxides (NOx) emissions at the turbine exhaust. The duct burners in the HRSGs will be equipped with low-NOx burners. Stack exhaust NOx emissions will be reduced to 2 parts per million volume dry basis corrected to 15 percent oxygen (ppmvdc) on a 24-hour average basis using selective catalytic reduction (SCR) with aqueous ammonia (NH_3). NH_3 emissions will be limited to 7 ppmvdc. Stack exhaust carbon monoxide (CO) emissions will be reduced to 2 ppmvdc using CO catalyst.

LCH is simultaneously submitting an application to the Texas Commission on Environmental Quality (TCEQ) for an air quality permit for this project, including all applicable State New Source Review (NSR) requirements and Federal Prevention of Significant Deterioration (PSD) requirements. Because the project is otherwise subject to PSD for other regulated NSR pollutants and the project has a greenhouse gas (GHG) potential to emit greater than 75,000 tpy carbon dioxide equivalent (CO_2e), PSD permitting of the GHG emissions is required. Permitting of GHG emissions in Texas is currently conducted by United States Environmental Protection Agency (US EPA) Region 6; therefore, a separate PSD permit application is required to be submitted to US EPA for GHG emissions. This document constitutes the application for the proposed Lon C. Hill Power Station GHG PSD permit.

The purpose of this application is to authorize the construction of the Lon C. Hill Power Station. Furthermore, this application will demonstrate that LCH has selected all the pollution control technologies in accordance with applicable Best Available Control Technology (BACT) requirements.

This report is organized as follows:

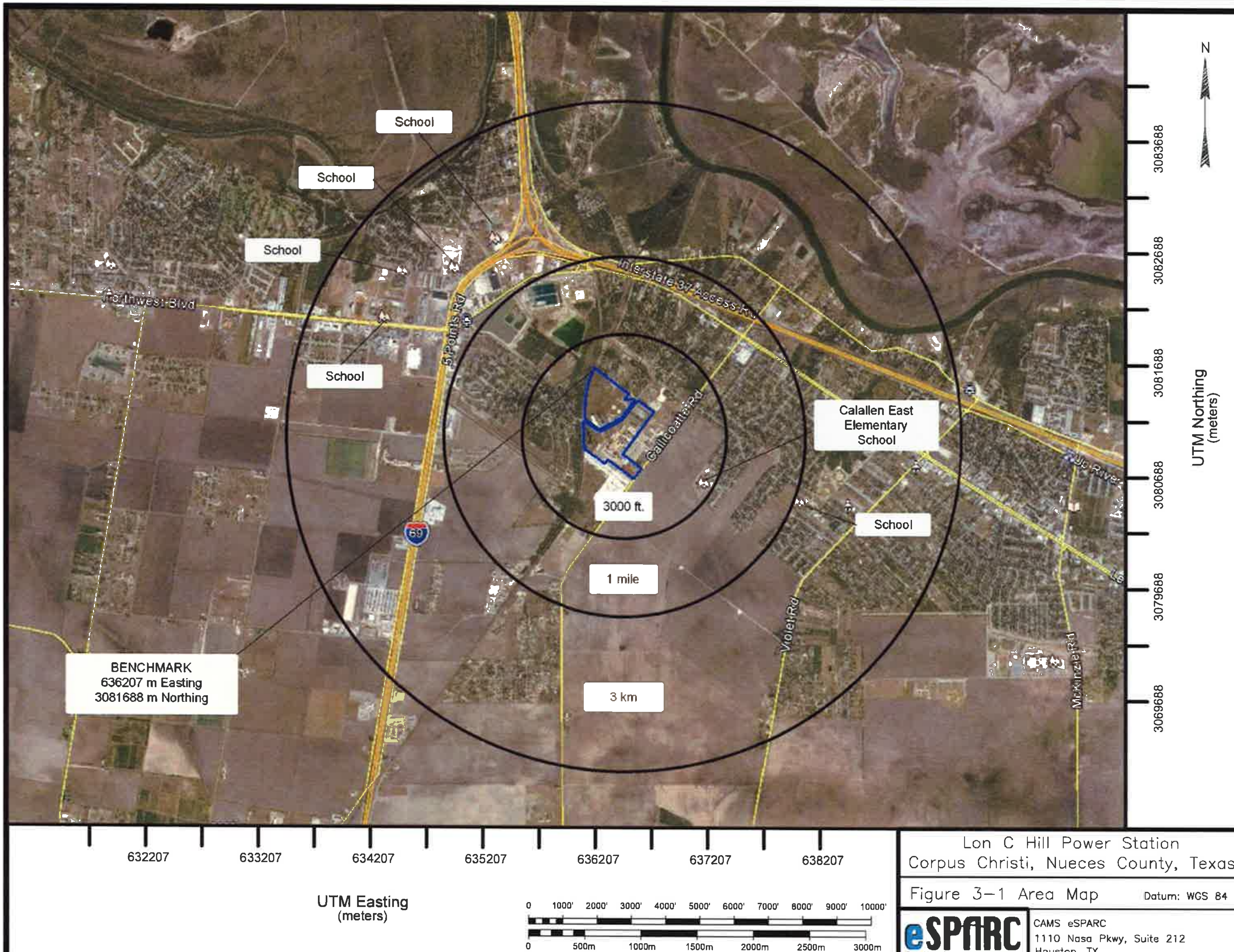
- Section 1 provides the required administrative information.
- Section 2 provides an introduction to the proposed project.
- Section 3 provides a detailed process description, including an area and plot plan showing the facility location and the emission point layout within property boundaries, and a process flow diagram of the proposed power station.
- Section 4 describes the GHG emission rate calculations and input data.
- Section 5 provides an analysis of BACT for GHG.

Section 3 Technical Information

3.1 Area Map, Plot Plan and Process Flow Diagram

Lon C. Hill Power Station will be located within TCEQ Region 14, Corpus Christi, Texas. The land surrounding the site is mostly suburban area. Calallen East Elementary School is within 3,000 feet of the site.

A copy of the Lon C Hill Power Station area map, a preliminary proposed plot plan and a process flow diagram are provided on the following pages.



Lon C Hill Power Station
Corpus Christi, Nueces County, Texas

Figure 3–1 Area Map

Datum: WGS 84

eSPARC

CAMS eSPARC
1110 Nasa Pkwy, Suite 212
Houston, TX

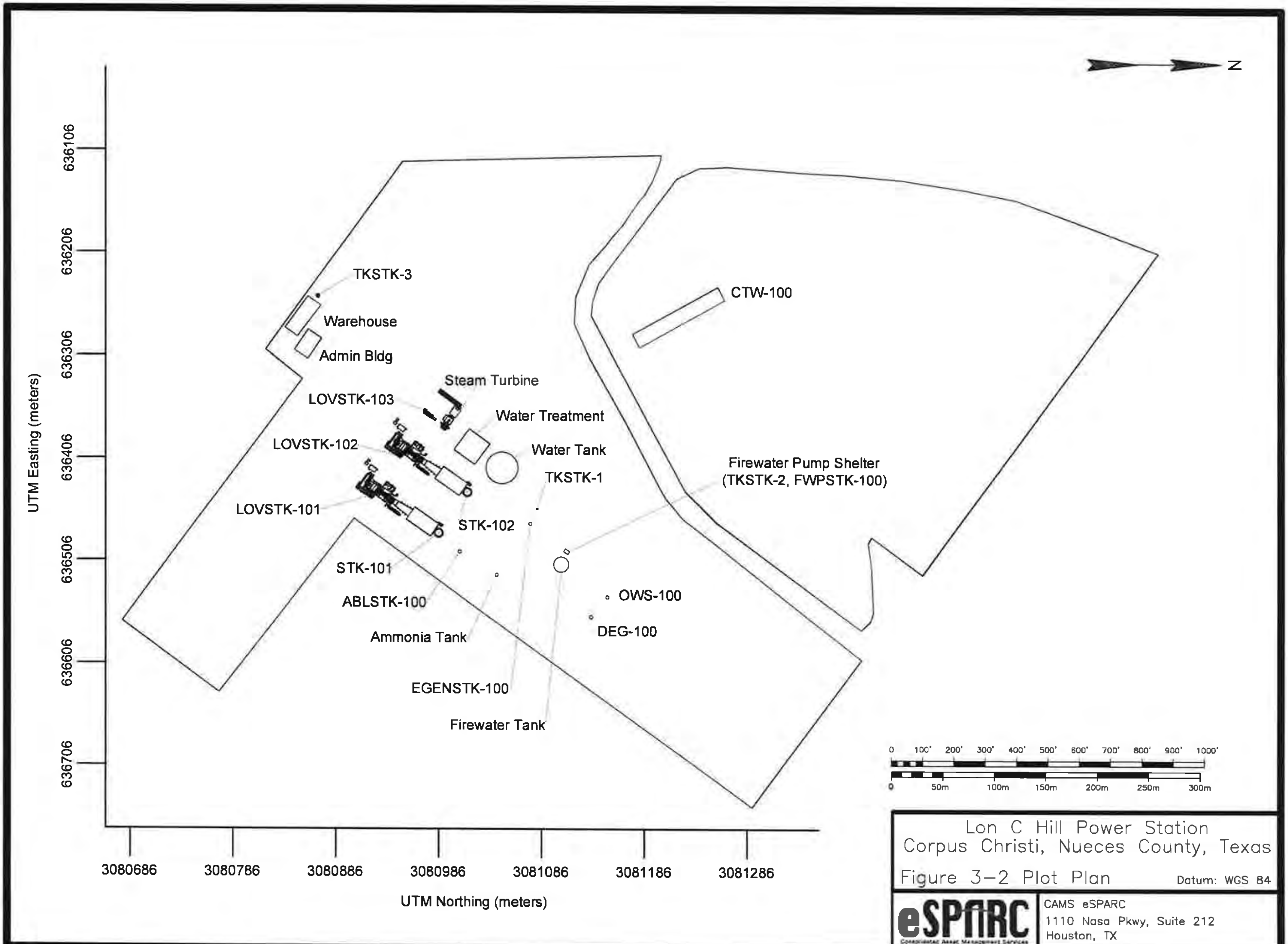
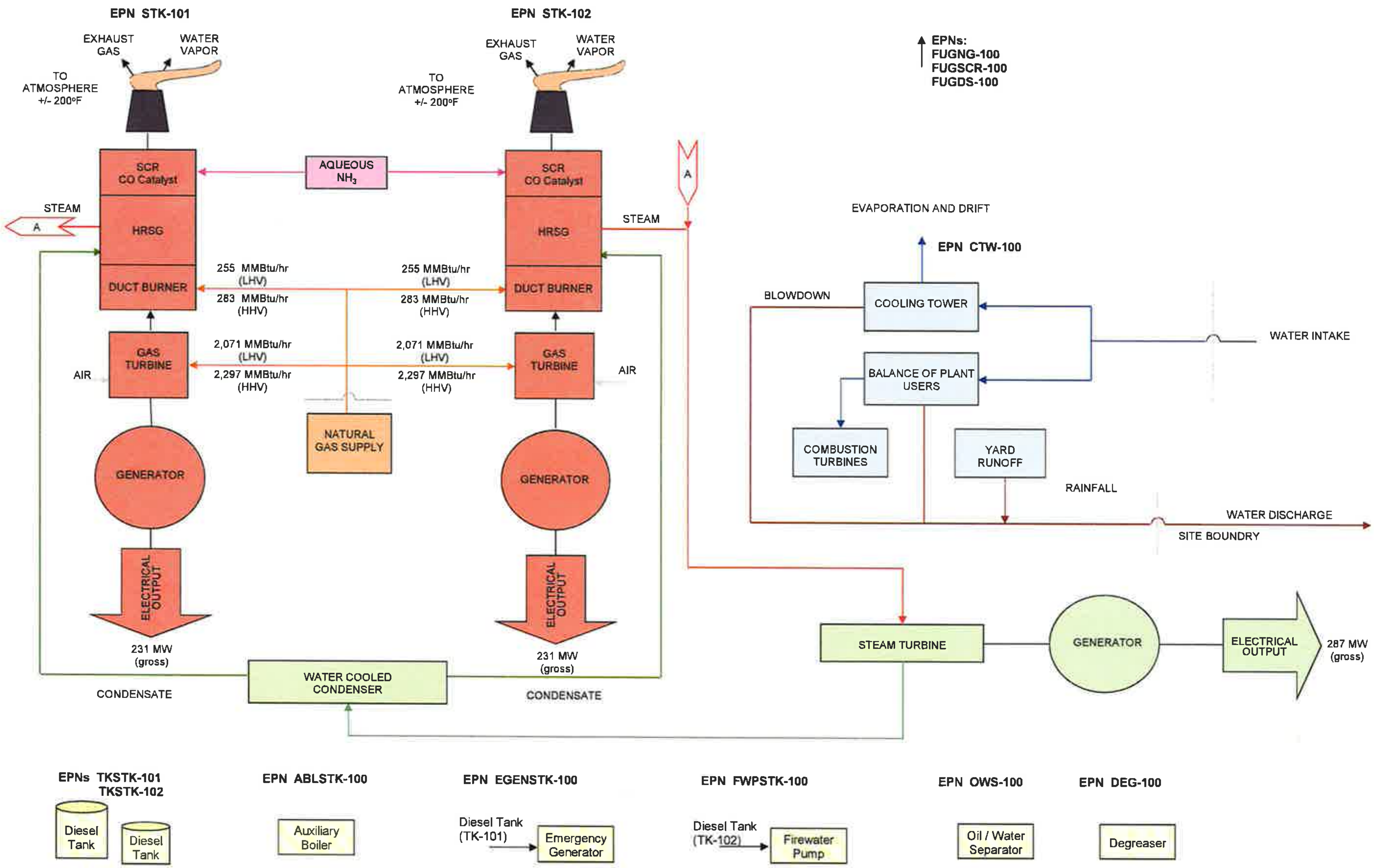


Figure 3-2 Plot Plan

LON C HILL REDEVELOPMENT PROJECT
LON C. HILL, LP

PROCESS FLOW DIAGRAM



3.2 Process Description

Lon C. Hill Power Station will be a 2x1 combined cycle power plant consisting of two natural gas-fired combustion turbines (GTs), two heat recovery steam generators (HRSGs) with natural gas-fired duct burners (DBs) and a steam turbine (ST) generator. The plant nominal operating capacity will be approximately 625 to 740 megawatts (MW). A process flow diagram illustrating the general plant configuration is included in Section 3.1.

Gas Combustion Turbines (GTs)

The main function of each GT is to produce shaft power to generate electricity. In each GT, large volumes of air are compressed to high pressures. The compressed air is subsequently injected, together with the combustion fuel, into the GT combustion chamber. The fuel for the units will be natural gas only. Hot gases from the combustion chamber turn the turbine that drives the compressor and the GT generator producing electricity before exhausting to the HRSG for steam production. Each HRSG contains a gas-fired duct burner assembly that supplements the steam production. The steam from the two HRSGs is then passed through a single steam turbine to generate additional electricity.

Each GT will be equipped with an inlet air filtration system and either an inlet chilling system or an evaporative cooling system, to pre-treat the combustion air. The inlet air filtration system removes the bulk of the particulate matter in the inlet air. The filtration improves both long-term compressor efficiency and compressor blade life, by reducing erosion and fouling of the GTs inlet air compressors. The inlet chilling, as well as the evaporative cooling, if installed, cools the inlet air to within a few degrees of the prevailing wet bulb temperature; this increases the output of the GTs and improves efficiency. Emission estimates for scenarios with and without cooling of the inlet air are provided in this application (Attachment B).

NOx emissions from the GTs will be controlled with DLN combustors in combination with a SCR. One aqueous ammonia tank will be installed as part of the project to supply ammonia to the SCR systems for both units. CO emissions from the GTs will be controlled with CO-oxidation catalysts.

The proposed new combined cycle facility will utilize either Siemens SCC6-5000F GTs with duct-fired HRSGs and a single SST6-5000 steam turbine or General Electric 7FA.04/7FA.05 GTs with duct-fired HRSGs and a single D-11 steam turbine. Each GT will have an estimated nominal gross output of approximately 195 to 240 MW. The ST is expected to generate approximately 230 to 290 MW.

The proposed GTs will generate carbon dioxide (CO_2) emissions from the combustion of methane and other minor hydrocarbon constituents of the natural gas. Small quantities of methane (CH_4) and nitrous oxide (N_2O) will also be emitted. A description of the emission rate calculation methodology is provided in Section 4.2.

Heat Recovery Steam Generators (HRSGs)

The HRSGs use the hot combustion gases exiting the GTs to produce steam. Indirect heating of the HRSG feed water produces steam at various pressure levels. Each HRSG is supplied with supplementary firing (duct burners) to increase the steam production as required to generate more power. The HRSG duct burners will be fired with natural gas only. The maximum firing rate of each duct burner system will be approximately 250 to 670 MMBtu/hr (HHV). The CO-oxidation catalyst and the SCR technology will be installed between the tube banks within the HRSGs.

The proposed HRSG duct burners will generate CO_2 emissions from the combustion of methane and other minor hydrocarbon constituents of the natural gas. Small quantities of CH_4 and N_2O will also be emitted. A description of the emission rate calculation methodology is provided in Section 4.2.

Lube Oil Vents

The combustion turbines and the steam turbine require lube oil reservoirs that can potentially emit small amounts of particulate matter through atmospheric vents. The lube oil vents will be equipped with mist eliminators with 99.9% efficiency. Consequently, associated particulate matter emissions are estimated to be below 0.1 pounds per hour (lb/hr) per vent. No GHG emissions are associated with these pieces of equipment.

Auxiliary Boiler

The design of the new facility includes a natural gas fired auxiliary boiler to provide pre-warming steam to the steam turbine generator prior to startup. Use of the auxiliary boiler will decrease the amount of time that the combustion turbines must be run at low output levels during startup, particularly during cold startups. The unit will nominally produce 31,000 pounds of steam per hour at a maximum heat input of 48.4 MMBtu/hr. The maximum annual capacity factor will be 30%.

The proposed auxiliary boiler will generate CO_2 emissions from the combustion of methane and other minor hydrocarbon constituents of the natural gas. Small quantities of CH_4 and N_2O will also be emitted. A description of the emission rate calculation methodology is provided in Section 4.2.

Emergency Generator

An emergency diesel-fired generator rated at approximately 1,000 kW (1,340 hp) will provide power to essential ancillary equipment in the event of a loss of primary power. This engine will operate no more than 100 hours per year for maintenance and testing purposes only [40 CFR 60, Subpart IIII (§60.4211(f)(2))]. The diesel engine has not yet been procured; however, LCH will ensure that the installed unit meets the emission requirements of 40 CFR 60, Subpart IIII, if applicable.

GHG emissions associated with the emergency generator will include CO_2, CH_4 and N_2O. A description of the emission rate calculation methodology is provided in Section 4.2. Though CO_2e emission rates for this unit are included in the facility potential to emit, it is not expected that the unit will have any reporting obligations through US EPA Electronic Greenhouse Gas Reporting Tool (eGGRT), according to §98.30(b)(2).

Firewater Pump

The project will include the installation of a firewater pump diesel engine rated at approximately 460 kW (617 hp). This engine will operate no more than 100 hours per year for maintenance and testing purposes only [40 CFR 60, Subpart IIII (§60.4211(f)(2))]. The firewater pump has not yet been procured, however, LCH will ensure that the installed unit meets the emission requirements of Table 4 of 40 CFR 60, Subpart IIII, if applicable.

GHG emissions associated with the firewater pump engine will include CO_2, CH_4 and N_2O. A description of the emission rate calculation methodology is provided in Section 4.2. Though CO_2e emission rates for this unit are included in the facility potential to emit, it is not expected that the unit will have any reporting obligations through US EPA Electronic Greenhouse Gas Reporting Tool (eGGRT), according to §98.30(b)(2).

Cooling Water System

LCH intends to utilize a cooling tower with a water-cooled condenser in order to minimize the station water demand. The preliminary cooling tower design considers the use of gray water from the City of Corpus Christi for cooling tower make up. Gray water may undergo filtration as needed. A portion of the cooling water circulation (blowdown) will be purged from the system to prevent concentrations of solids or other constituents in the circulating water from building up to unacceptable levels. The cooling water drift factor rate will not exceed 0.001%. No GHG emissions are associated with this equipment.

Oil/Water Separator

The site will be equipped with an oil/water separator to treat oil impacted water effluents. The oil/water separator could potentially emit small amounts of volatile organic compounds to the atmosphere. The preliminary design includes a 96,000 gallon per year unit. No GHG emissions are associated with this equipment.

Degreaser

A degreaser unit will be installed at the site. The degreaser could potentially emit small amounts of volatile organic compounds to the atmosphere. The preliminary design includes a 220 gallon per year unit. No GHG emissions are associated with this equipment.

Storage Tanks

There will be two dedicated storage tanks to supply diesel fuel to the emergency generator and the fire water pump engines. The preliminary design includes a 700 gallon tank for the emergency generator and a 300 gallon tank for the firewater pump.

In addition, there will be an aqueous ammonia storage tank for use in the SCR systems. The aqueous ammonia tank will be pressurized and therefore will have no emissions to the atmosphere. The preliminary design includes a 25,000 gallon tank to serve both combined cycle units.

The new plant may include containing 250 gallon tank for gasoline storage. This fuel will be used in miscellaneous plant equipment. It is expected that no more than 250 gallons of gasoline will be used annually. No GHG emissions are associated with these pieces of equipment.

Section 4
Emission Data and Calculations

This section describes the methods used to estimate the GHG emission rates associated with the proposed project. The GHG emission sources are listed in Table 1. Refer to Attachment B for detailed calculations.

4.1 EPN-FIN Cross Reference Table

Table 1– EPN-FIN Cross Reference

EPN	FIN	Description
STK-101	CC-101	Unit 1 Combined Cycle (GT+HRSG DB)
STK-102	CC-102	Unit 2 Combined Cycle (GT+HRSG DB)
ABLSTK-100	ABL-100	Auxiliary Boiler
EGENSTK-100	EGEN-100	Emergency Generator
FWPSTK-100	FWP-100	Firewater Pump
FUGNG-100	FUGNG-100	Fugitive Natural Gas Service GHG emissions
SF6-100	SF6-100	Insulation Breaker Fugitives

4.2 Emission Rate Calculations

Combined Cycle Units (FINs: CC-101 and CC-102; EPNs: STK-101 and STK-102)

Two combined cycle gas turbine generators nominally rated at approximately 195 to 240 MW of power (gross) and two HRSGs equipped with supplemental duct burner firing are proposed. The maximum firing rate of the HRSG duct burners is approximately 250 to 670 MMBtu/hr (HHV) for each train. The GTs and HRSG duct burners will be fired with natural gas only.

GHG emission rates from the combined cycle units are calculated in accordance with US EPA "PSD and Title V Permitting Guidance for GHG" (EPA-457/B-11-001, March 2011). The CO_2 emission factor (118.8 lb/MMBtu) is calculated using 40 CFR Part 75, Appendix G, equation G-4. CH_4 and N_2O are calculated according to §98.43(a)(2), using §98.33(c)(4), equation C-10 (Tier 4 methodology) and default emission factors from 40 CFR 98, Subpart C, Table C-2 for natural gas fired units.

Annual emission limits are proposed based on the maximum annual heat input for all scenarios evaluated, as summarized in Table 2:

Table 2– GT/HRSG Operating Scenarios

GT	Scenario	Ambient Temperature (°F)	Evaporative Coolers or Chillers	Duct Firing	Hours of Operation	Heat Input (MMBtu/yr)
Siemens SCC6-5000F	1	45	OFF	ON	8,760	20,993,770
	2	65	OFF	ON	8,760	21,058,204
	3	75	ON	ON	8,760	21,136,220
	4	*	OFF	ON	8,760	21,014,826
GE S207FA.04	1	13	OFF	ON	8,760	18,238,471
	2	60	ON	ON	8,760	16,171,009

*45 °F ambient temperature from April through October (to simulate evaporative coolers/chiller on) and 60 oF from November through March

The annual GHG emission rates are based on the maximum heat input of these scenarios (21,136,220 MMBtu/yr). These scenarios represent the range of expected operations necessary for the plant to respond to market demands. The calculated CO_2, CH_4 and N_2O short tons are converted into CO_2e using 40 CFR 98 Subpart A, Table 1 global warming potentials.

During startup and shutdown events, emissions of GHGs are not elevated above routine levels; therefore, alternate emission rates were not calculated for these periods. Emissions during startup and shutdown events will be counted toward the total annual emission rates for the purpose of assessing compliance with the proposed annual CO_2e emission rate limits. Detailed emission rate calculations and example calculations are provided in Attachment B.

Auxiliary Boiler (FIN: ABL-100; EPN: ABLSTK-100)

The auxiliary boiler will fire only natural gas. The auxiliary boiler maximum heat input is 48.4 MMBtu/hr and the annual hours of operation will be limited to 2,628 hours (30% capacity factor).

GHG emission rates from the auxiliary boiler are calculated in accordance with US EPA "PSD and Title V Permitting Guidance for GHG" (EPA-457/B-11-001, March 2011), using §98.33(a)(1), equation C-1 (Tier 1 methodology) and default emission factors for natural gas fired units from 40 CFR 98, Subpart C, Table C-1 for CO_2 and Table C-2 for CH_4 and N_2O. The calculated CO_2, CH_4 and N_2O short tons are converted into CO_2e using 40 CFR 98 Subpart A, Table 1 global warming potentials.

During startup and shutdown events, emissions for GHGs are not elevated above routine levels; therefore, alternate emission rates were not calculated for these periods. Emissions during startup and shutdown events will be counted toward the total annual emission rates for the purpose of assessing compliance with the proposed annual CO_2e emission limits. Detailed emission rate calculations and example calculations are provided in Attachment B.

Emergency Generator (FIN: EGEN-100; EPN: EGENSTK-100)

The emergency generator is expected to be a 1,000 kW (1,340 HP) diesel fired engine operating no more than 100 hours per year. GHG emission rates are calculated in accordance with US EPA "PSD and Title V Permitting Guidance for GHG" (EPA-457/B-11-001, March 2011), using §98.33(a)(1), equation C-1 (Tier 1 methodology) and default emission factors for diesel fired units from 40 CFR 98, Subpart C, Table C-1 for CO_2 and Table C-2 for CH_4 and N_2O. The calculated CO_2, CH_4 and N_2O short tons are converted into CO_2e using 40 CFR 98 Subpart A, Table 1 global warming potentials. CO_2e emission rates for this unit are included in the facility potential to emit. However, it is not expected that the unit will have any reporting obligations through eGGRT, according to §98.30(b)(2).

Firewater Pump (FIN: FWP-100; EPN: FWPSTK-100)

The firewater pump is expected to be a 460 kW (617 HP)diesel fired engine operating no more than 100 hours per year. GHG emission rates are calculated in accordance with US EPA "PSD and Title V Permitting Guidance for GHG"(EPA-457/B-11-001, March 2011), using §98.33(a)(1), equation C-1 (Tier 1 methodology) and default emission factors for diesel fired units from 40 CFR 98, Subpart C, Table C-1 for CO_2 and Table C-2 for CH_4 and N_2O. The calculated CO_2, CH_4 and N_2O short tons are converted into CO_2e using 40 CFR 98 Subpart A, Table 1 global warming potentials. CO_2e emission rates for this unit are included in the facility potential to emit. However, it is not expected that the unit will have any reporting obligations through eGGRT, according to §98.30(b)(2).

Fugitive Emissions (FIN: FUGNG-100; EPN: FUGNG-100)

Fugitive releases of CH_4 may originate from the natural gas fuel lines that provide fuel to the combustion turbines, HRSG duct burners and auxiliary boiler. Emission rates were estimated based on the preliminary design component counts. Emission factors used were obtained from TCEQ's "Technical Guidance for Chemical Sources – Equipment Leak Fugitives" (Draft, October 2000). No control efficiency is claimed for natural gas. The calculated fugitive methane emission rate was subsequently converted to CO_2e using 40 CFR 98 Subpart A, Table 1 global warming potential for CH_4. Detailed emission rate calculations and example calculations are provided in Attachment B.

Insulation Breakers (FIN: SF6-100; EPN: SF6-100)

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_6provided by the circuit breaker's vendor specifications. The annual leak rate used is based on IEC Standard for new equipment leakage, as published on "SF_6 Leak Rates from High Voltage Circuit Breakers - U.S. EPA Investigates Potential Greenhouse Gas Emission Sources" (J. Blackman, et al.).

Section 5
BACT Analysis

This section presents the GHG Best Available Control Technology (BACT) analysis for the proposed redevelopment of the Lon C. Hill Power Station. PSD regulations require that BACT be used to minimize the emissions of pollutants subject to PSD review from a new major source or a major modification of an existing major source. BACT is determined on a case-by-case basis taking into consideration economic, environmental, and energy impacts, and technical feasibility. BACT must be applied to each new or modified emission point of the pollutants subject to review. The only PSD pollutant addressed in this permit application is GHG.

BACT selection is based on the US EPA recommended five-step "top-down" methodology. First, all available control alternatives are identified for each new or modified source of significant pollutants. The identification of control alternatives is performed through knowledge of the applicant's particular industry and previous regulatory decisions for identical or similar sources. A detailed search of the latest RACT/BACT/LAER Clearinghouse (RBLC) database for natural gas fired combined cycle units was completed. Summary tables are included in Attachment C. In the second step, technically infeasible alternatives are dismissed based on either physical or chemical principles. Remaining alternatives are then rank-ordered beginning with the most stringent control and working down to form a control technology hierarchy in the third step. In the fourth step, the ranked technologies are evaluated for their energy, environmental and economic impact. If these considerations do not justify eliminating the top-ranked option, it should be selected as BACT at the fifth step. However, if the energy, environmental, or economic impacts of the top-ranked option demonstrate that this option is not achievable, then the evaluation of this option stops at Step 4 of the process and continues with an examination of the energy, environmental, and economic impacts of the second-ranked option, third-ranked option, etc. The results of the first four steps are used to select the most appropriate BACT in the fifth step. The discussion of proposed BACT for each source type is provided in the following sections.

5.1 Summary of BACT

Table 3 summarizes the control technologies proposed for the Lon C. Hill Power Station to meet BACT for GHG. The remainder of this section describes the individual BACT analyses for the proposed new sources with associated GHG emissions.

Table 3 – Summary of GHG BACT Control Methods for Lon C. Hill Power Station

Proposed BACT	Proposed Performance Standard	Averaging Period
Combined Cycle Units		
Combined cycle power generation technology. Natural gas only. 2x1 configuration. Efficient GT design and practices. Efficient HRSG design and practices. Fuel Flow meter calibration 40 CFR 75.	7,730 Btu/kWh (HHV, 2x1 configuration, unfired, adjusted base load nominal output heat rate) 830 – 920 lb_{CO2}/MWh (gross)	12-month rolling
Auxiliary Boiler		
Natural gas only. Good combustion practices. Maximum capacity factor: 30%		
Emergency Generator		
Limited use (≤100 hr/yr)		
Firewater Pump		
Limited use (≤100 hr/yr)		
Fugitive Emissions		
None		
Breakers Insulation Leaks		
Totally enclosed circuit breakers		

5.2 BACT Analysis for the Combined Cycle Units

This section addresses BACT requirements for emissions of GHG from the GTs/HRSGs. The proposed combined cycle units will generate CO_2 emissions from the combustion of methane and other minor hydrocarbon constituents of the natural gas. Small quantities of CH_4 and N_2O will also be emitted.

BACT Step 1 – Identify All Available Control Technologies

A RBLC database search of GHG emissions from large natural gas fired combustion turbines was conducted to identify potential controls and performance standards and is provided in Attachment C. Based on this database search and other permit applications that have been submitted to US EPA Region 6 for similar facilities, the following potentially applicable GHG control technologies and operating practices were identified.

Table 4 – Natural Gas Fired Combined Cycle GHG Control Technologies

Control Technology	Description
Use of Combined Cycle Power Generation Technology	The most efficient way to generate electricity from a natural gas fuel source is the use of a combined cycle design, in which the HRSG is used to recover waste heat that would otherwise be lost to the atmosphere in the turbine exhaust. The recovered heat and produced steam allows generation of additional electric power by a steam turbine. The overall efficiency may be increased from about 30% for a simple cycle (no heat recovery) unit to about 50% for a combined cycle unit.
Use of Multiple Trains Combined Cycle Units	Combustion turbine efficiency is highest at full design load. The use of multiple trains (e.g. 2x1 configurations) allows one or more trains to be shut down while the remaining unit(s) operates at or near full load, where maximum efficiency is achieved, rather than operating a single unit at lower, less efficient loads to meet market demand. Due to the variability of electricity demand, this flexibility helps maintain operational efficiency.
Use of Natural Gas	Natural gas has the lowest carbon intensity among available fossil fuels. According to the comprehensive analysis by the Center of Climate and Energy Solutions ("Leveraging Natural Gas to Reduce Greenhouse Gas Emissions", June 2013[1]) on average, natural gas combustion releases approximately 50 percent less CO_2 than coal and 33 percent less CO_2 than oil (per unit of useful energy). Therefore, the burning of natural gas only will reduce the carbon footprint when compared to other fossil fuels available.
Gas Combustion Turbine Design	State-of-the-art combustion turbines operate at high temperatures due to the heat of compression and the thermal heat of combustion. The higher the operating temperature, the higher the turbine efficiency. To minimize the heat loss from the combustion turbines and protect the personnel and equipment around the units, insulation blankets are applied to the combustion turbine casing. These blankets minimize the heat loss through the combustion turbine shell. Improved design elements (e.g., two-bearing, axial exhaust, cold-end drive designs, etc.) have significantly increased overall combustion efficiency.

Continues on the following page

[1] http://www.c2es.org/publications/leveraging-natural-gas-reduce-greenhouse-gas-emissions

Table 4 – Natural Gas Fired Combined Cycle GHG Control Technologies (*continued*)

Control Technology	Description
Fuel Pre-Heating	Thermal efficiency of the turbine can be increased by pre-heating the fuel prior to combustion. This is usually accomplished by heat exchange using steam from the HRSG or hot GT compressor bleed air.
Inlet Evaporative Cooling or Chillers	Use of inlet evaporative coolers or chillers reduces the inlet air temperature, during high ambient temperature conditions, increasing the air density and hence the mass flow through the combustion turbine increases. As the mass flow through the combustion turbine increases, more power is generated, hence the turbine efficiency increases.
Periodic Maintenance and Burner Tuning	Regularly scheduled maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. A periodic maintenance program consisting of inspection and cleaning of key equipment components and tuning of the combustion system will minimize performance degradation and recover thermal efficiency to the maximum extent possible.
Instrumentation and Control Systems	State-of-the-art combustion turbines have sophisticated instrumentation and control systems to automatically control the operation of the combustion turbine, including the fuel feed and burner operations to achieve low-NOx combustion. The control systems monitor the operation of the unit and modulate the fuel flow and turbine operation to achieve optimal high-efficiency low-emission performance for full load and part load conditions.
HRSG Design	HRSGs are heat exchangers designed to capture as much thermal energy as possible from the combustion turbine exhaust gases. State-of-the-art HRSG heat transfer sections are made up of many thin-walled tubes to provide surface area to maximize the transfer of heat to the working fluid. Most of the tubes also include extended surfaces (e.g., fins). The extended surface optimizes the heat transfer, while minimizing the overall size of the HRSG. Additionally, flow guides are used to distribute the flow evenly through the HRSG to allow for efficient use of the heat transfer surfaces and post-combustion emission control components. Low-temperature economizer sections, employ recirculation systems to minimize cold-end corrosion and stack dampers are used for cycling operation to conserve thermal energy within the HRSG when the unit is off line. Overall efficiency of the HRSG is improved by using insulation to minimize heat loss to the surroundings.

Continues on the following page

Table 4 – Natural Gas Fired Combined Cycle GHG Control Technologies (*continued*)

Control Technology	Description
Minimizing HRSG Heat Transfer Surfaces Fouling	Fouling of interior and exterior surfaces of the HRSG heat exchanger tubes hinders the transfer of heat from the combustion turbine hot exhaust gases to the boiler feedwater. This fouling occurs from contaminants in the turbine inlet air and in the feedwater. Fouling is minimized by turbine inlet air filtration, maintaining proper feed water chemistry, and periodic maintenance, including cleaning the tube surfaces as needed during scheduled equipment outages. By reducing the fouling, the efficiency of the unit is maintained.
Steam Turbine Design	State-of-the-art steam turbines are designed to be highly efficient units. The overall efficiency of the unit is primarily affected by the inlet and outlet steam conditions, the blade ring design, the steam turbine seals and the generator efficiency. New unit designs achieve higher overall performance, reducing startup times significantly and consequently increasing the efficiency of the combined cycle unit as a whole.
Periodic Steam Turbine Maintenance	Regularly scheduled maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. A periodic maintenance program consisting of inspection and cleaning will minimize performance degradation and maintain optimal use of the steam that is delivered from the HRSG.
Add-On Controls	CO_2 Capture and Sequestration (CCS) is an emerging technology that consists of processes to capture (separate) CO_2 from the combustion exhaust gases and then transport it and inject it into geologic formations, such as oil and gas reservoirs, unminable coal seams, and underground saline formations. CCS could account for up to 90 percent[2] of the emissions mitigation needed to stabilize and ultimately reduce concentrations of CO_2.

BACT Step 2 – Eliminate Technically Infeasible Options

All options identified in Step 1, with the exception of CCS are considered technically feasible for the proposed combined cycle units and are common practice on state-of-the-art combined cycle units.

Although CCS is a promising technology, in order to enable widespread, safe and effective CCS, large-scale project studies still need to be completed to demonstrate that the capacity required for the purposes of GHG emissions mitigation at a typical power plant is met. The results from the RBLC database search show no such technology has yet been used for any natural gas fired combined cycle plant (refer to Attachment C). Each component of CCS technology (i.e., capture, transport and storage) is discussed in the following paragraphs.

[2] Report of the Interagency Task Force on Carbon Capture and Storage, August 2010

CO_2 Capture

CCS could become a viable emission management option as new CO_2 capture technologies are developed. According to the US Department of Energy National Energy and Technology Laboratory (DOE-NETL), a 2009 review of commercially available CO_2capture technologies presented that facilities capturing the highest volumes of CO_2 were all associated with gas streams containing relatively high concentrations of CO_2 (25 to 70 percent) such as natural gas processing operations and synthesis gas production. Capturing $CO_2$from more dilute streams, such as those generated from power production, is less common as the following challenges are faced:

- CO_2 is present at low pressure (15-25 psia) and dilute concentrations (3-4 percent volume) from the gas-fired turbine exhaust stream. Therefore, a very high volume of gas must be available to achieve the CO_2 mass flow necessary to recover CO_2 at a cost efficiency comparable to an application such as natural gas processing.
- Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the exhaust gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.
- Compressing the captured CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) presents a large auxiliary power load on the overall power plant system.

Current industrial processes generally involve gas streams that are much lower volumes than that required for the purposes of GHG emissions mitigation at a typical power plant. Scaling up these existing processes represents a significant technical challenge and a potential barrier to widespread commercial deployment in the near term. No references to natural gas fired power plants using CCS were identified.

The combustion of natural gas at the proposed Lon C. Hill Power Station will produce an exhaust gas with a maximum CO_2 concentration of 4.5 volume percent. This low concentration stream will require that a very high volume of gas be treated so that the CO_2 may be captured effectively. However, the CO_2 capture capacities used in current industrial processes are designed for relatively high CO_2 concentration streams (25 percent or higher), as discussed in the "Report of the Interagency Task Force on Carbon Capture and Storage" (August 2010)[3].

CO_2 Transport

Even if it is assumed that CO_2 capture could feasibly be achieved for the proposed project, the high-volume CO_2 stream generated (maximum 45,807 scf/min of CO_2) would need to be transported to a facility capable of storing it. Figure 1 is a map showing the location of current CO_2 pipelines in the United States.

[3]http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf

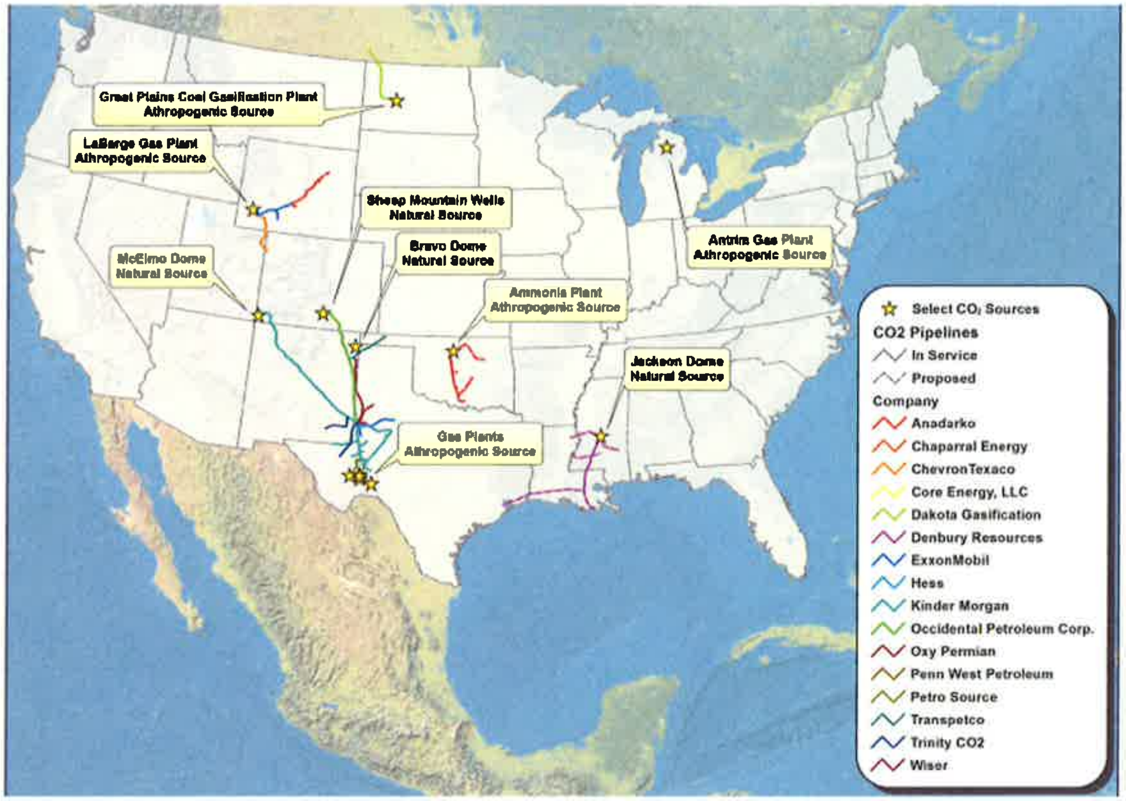


Figure 1 – Existing and Planned CO_2 Pipelines in the United States
[Source: Report of the Interagency Task Force on Carbon Capture and Storage, Fig. B-1, August 2010]

As shown on this map, there are no existing pipelines that could transport the CO_2 stream from the proposed plant to any potential storage facility. The closest site to the proposed project, with some demonstrated capacity for geological storage of CO_2, is the Scurry Area Canyon Reef Operators (SACROC) oilfield near the eastern edge of the Permian Basin in Scurry County, Texas[4]. This site is over 390 miles away from Lon C. Hill Power Station; therefore, a very long and sizable pipeline would be required to transport the large volume of high pressure CO_2 from the plant to the storage facility which will make CCS economically infeasible. Several other candidate storage reservoirs exist within 10 to 50 miles from the proposed project along the east Texas' basins (see Figure 2); however, none have been confirmed to be viable for large scale CO_2 storage at this time.

CO_2 Storage

Even if it is assumed that CO_2 capture could feasibly be achieved for the proposed project and that the CO_2 could be transported economically, the feasibility of CCS would still depend on the availability of a long-term safe storage site.

Ongoing regional-scale assessments suggest a large resource potential for storage in the United States. According to the National Carbon Sequestration Database and Geographic Information System

[4]http://www.beg.utexas.edu/gccc/sacroc.php

(NATCARB)[5] Texas CO_2 potential storage resources are within 441,283 metric tons (low estimate) and 4,297,550 metric tons (high estimate) including saline formations, unminable coal seams and oil/gas reservoirs. Figure 2 shows the Basins outlines in the United States, as provided by NATCARB 2012 United States and Canadian Carbon Storage Atlas.

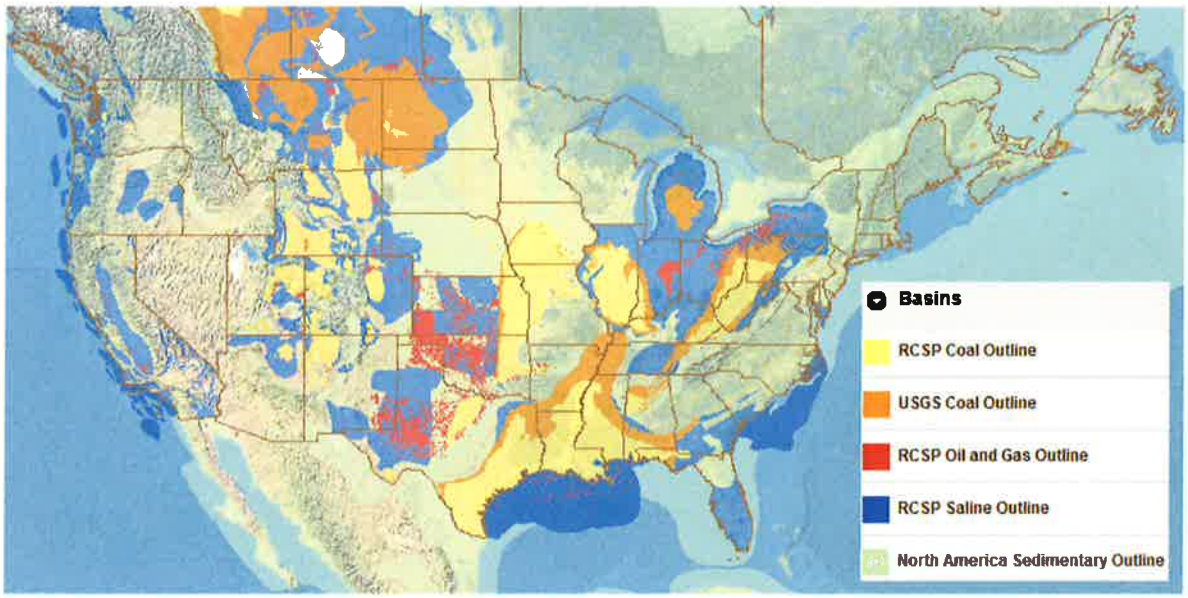


Figure 2 –Basins Outlines in United States
[Source: NATCARB 2012 United States and Canadian Carbon Storage Atlas]

According to the conclusions of the "Report of the Interagency Task Force on Carbon Capture and Storage" (August 2010)[6], to enable widespread, safe, and effective CCS, CO_2 storage should continue to be field-demonstrated for a variety of geologic reservoir classes, with large-scale projects targeted at high-priority reservoir classes and smaller-scale projects covering a wider range of classes that are important regionally.

Small and large-scale field tests in different geological storage classes are being conducted to confirm that CO_2 capture, transportation, and storage can be achieved safely, permanently, and economically. Results from these tests will provide a more thorough understanding of migration and permanent storage of CO_2 within various open and closed depositional systems. The storage types and formations being tested are considered regionally significant and are expected to have the potential to store hundreds of years of CO_2 stationary source emissions.

Accounting that permanent CO_2 storage in geologic formations may not be a viable option for all CO_2 emitters and that this option could result in no environmental benefit at significant cost, the DOE-NETL[7]

[5]http://www.netl.doe.gov/technologies/carbon_seq/natcarb/index.html
[6]http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf
[7]http://www.netl.doe.gov/technologies/iccs/index.html

is also researching the development of alternatives that can use captured CO_2or convert it to a useful product, such as a fuel, chemical, or plastic, with revenue from the CO_2 use offsetting a portion of the CO_2 capture cost.

Based on the reasons provided above, CCS has only been effectively proven in small scale projects in specific regions, and is therefore considered technically infeasible for this project.

BACT Step 3 - Rank Remaining Control Technologies

The technically feasible options for GHG emission mitigation in order of most to least effective include:

- Use of combined cycle power generation technology;
- Use of natural gas;
- Instrumentation and control systems;
- Gas combustion turbine design;
- HRSG design;
- Minimizing HRSG heat transfer surfaces fouling;
- Inlet evaporative cooling or chillers;
- Fuel pre-heating;
- Use of multiple trains combined cycle units; and
- Periodic maintenance and burner tuning.

BACT Step 4 - Evaluate Most Effective Control Technologies

All of the technically feasible technologies discussed in Step 1 through Step 3 are being proposed for this project. Therefore, an examination of the energy, environmental, and economic impacts of the efficiency designs is not necessary for this application.

BACT Step 5 - Selection of BACT

LCH proposes as BACT for the combined cycle units the following energy efficiency processes, practices and designs:

- Use of combined cycle power generation technology;
- Use of natural gas only to fire both the GTs and the HRSG duct burners;
- Use of 2x1 configuration, allowing operation with one train full load or two trains full load on demand basis;
- Combustion turbine energy efficiency processes, practices and designs:
  - Efficient design of the turbine compressor, combustor, and blades
  - Periodic gas turbine burner tuning, following vendor's recommended comprehensive inspection and maintenance programs

- Reduction of heat loss
- Instrumentation and controls, including – fuel gas flow rate; exhaust gas temperature monitoring; turbine package temperature and pressure monitoring; combustion dynamics monitoring, vibration monitoring; air/fuel ratio monitoring; and HRSG temperature and pressure monitoring
- Inlet evaporative cooling or chillers

- HRSG Energy Efficiency Process, Practices and Designs:
  - Efficient heat exchanger design
  - Insulation of HRSG
  - Minimizing fouling of heat exchange surfaces, implementing vendor's recommended comprehensive inspection and maintenance program
- Calibrate and perform preventive maintenance on the fuel flow meters as required by 40 CFR Part 75, Appendix D, Section 2.1.6 (Quality Assurance);
- Maintain an unfired adjusted base load nominal output heat rate of approximately 7,730 Btu/kWh (HHV), for a 2x1 configuration, expressed on a 12-month rolling average basis for the proposed combined cycle units. The 7,730 Btu/kWh heat rate incorporates a margin factor to account for design margin and degradation of the equipment. This heat rate is equivalent to an output based CO_2 rate of 830 - 920 lb_{CO2}/MWh (gross), which meets the US EPA proposed new fossil-fuel-fired power plant output-based standard of 1,000 lb CO_2/MWh gross[8].

The proposed efficiency performance standard has been calculated based on the net heat rate provided by the vendor specifications without duct firing. Table 5 compares this rate with those proposed on recently permitted facilities in Texas with similar characteristics.

Table 5 – Proposed Efficiency Standards for Facilities Recently Permitted by US EPA Region 6

Project	Performance Standard (Btu/kWh)	Comments
Proposed Lon C. Hill Power Station	7,730 (HHV)	Combined cycle units base load without duct firing, 2x1 configuration (Siemens SCC6-5000F or GE S207FA.04).
LCRA Thomas Ferguson	7,720 (LHV)	Combined cycle units w/o duct burners, GE7A or Siemens SGT6-5000F
Calpine Channel Energy Center	6,852 (HHV)	Combined cycle cogeneration units without duct firing. Siemens 501FD3
Calpine Deer Park Energy Center	7,730 (HHV)	Combined cycle cogeneration units without duct firing. Siemens 501FD3

[8] US EPA fact sheet on "Proposed Carbon Pollution Standard for New Power Plants", http://epa.gov/carbonpollutionstandard/pdfs/20120327factsheet.pdf

5.3 BACT Analysis for the Auxiliary Boiler

The auxiliary boiler will have a maximum firing rate of 48.4 MMBtu/hr (HHV) and will be exclusively fired with natural gas. The boiler will be equipped with low NOx burners and will be limited to a maximum capacity factor of 30%. RBLC database search shows good combustion practices, annual boiler tune-ups and heat loss minimization as proposed BACT. Refer to Attachment C for further details.

Good combustion practices, firing natural gas and limiting the maximum capacity factor to 30% will be used to satisfy BACT requirements for the CO_2 emissions associated with auxiliary boiler.

5.4 BACT Analysis for the Emergency Diesel Generator

The emergency diesel generator will be operated for no more than 100 hours per year. This limited operating time inherently limits emissions. RBLC database search shows fuel efficient design as proposed BACT. Refer to Attachment C for further details. No controls are proposed to satisfy BACT requirements.

5.5 BACT Analysis for the Firewater Pump

The diesel fired firewater pump will be operated for no more than 100 hours per year. This limited operating time inherently limits the emissions. RBLC database search shows fuel efficient design as proposed BACT. No controls are proposed to satisfy BACT requirements.

5.6 BACT Analysis for the Site Fugitive Emissions

Methane fugitive emissions may be generated from the natural gas delivery system. These fugitive emissions were estimated using TCEQ recommended emission factors and 40 CFR Part 98 proposed global warming potential for methane.

BACT for process fugitives typically consists of leak detection and repair (LDAR) program intended to minimize the amount of time a leak goes undetected, and thus reduce emissions. However, the RBLC database search shows no proposed BACT. Because the conservatively calculated CO_2e fugitive emissions from the proposed project will be of 876 tpy (less than 0.03% of the combustion turbines emission rate) LCH proposes that a LDAR program is not necessary to satisfy BACT requirements. However, the lines will be periodically inspected and any leaks will be repaired as necessary.

5.7 BACT Analysis for the SF_6 Breakers Insulation

Sulfur hexafluoride (SF_6) emissions could potentially occur due to the leak of the breakers insulation. Proposed units will include totally enclosed circuit breakers. Though there should be no bleeding of SF_6 to the atmosphere, SF_6 fugitive emissions were conservatively estimated using the vendor specified SF_6

content in the GT and ST breakers and an estimated annual leak rate as recommended by the IEC Standard for new equipment leakage[9]. The RBLC database search shows enclosed circuit breakers as proposed BACT (refer to Attachment C). The St. Joseph Energy Center LLC (IN), a 1,300 MW station, proposed enclosed circuit breakers with leak detection claiming an SF6 emission rate of 0.0009 tpy. Because the calculated maximum SF_6 fugitive emissions from the proposed project will be of 0.0002 tpy, LCH proposes that a leak detection system is not necessary to satisfy BACT requirements.

[9] "SF6 Leak Rates from High Voltage Circuit Breakers" U.S. EPA Investigates Potential Greenhouse Gas Emission Sources" (J. Blackman, et al.)

Attachment A
FNSR Applicability Forms

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	TBD	Application Submittal Date:	November 7, 2013
Company:	Lon C. Hill LP		
RN:	RN100215979	Facility Location:	3501 Callicoatte Rd, Corpus Christi, Texas
City:	Corpus Christi	County:	Nueces
Permit Unit I.D.:	TBD	Permit Name:	Lon C Hill Power Station
Permit Activity:	☒ New Source	☐ Modification	

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS							
	Ozone		CO	PM_{10}	$PM_{2.5}$	NO_X	SO_2	Other[1] CO_2e
	VOC	NO_x						
Nonattainment Potentially Applicable?								No
PSD Potentially Applicable?								Yes
Existing site PTE (tpy)?								0.0
Proposed project emission increases (tpy from 2F[2])								2,522,122
Is the existing site a major source?								No
If not, is the project a major source by itself?								Yes
If site is major source, is project increase significant?								Yes
If netting required, estimated start of construction:			01-May-15					
5 years prior to start of construction contemporaneous			01-May-10					
Estimated start of operation period			01-Apr-17					
Net contemporaneous change, including proposed project, from Table 3F. (tpy)								2,522,122
Major NSR Applicable?	No	No	No	No	No	No	No	Yes

[1] Other pollutants. [Pb, H_2S, TRS, H_2SO_4, Fluoride excluding HF, etc.]

[2] Sum of proposed emissions minus baseline emissions, increases only.

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

TCEQ

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	CO_2e	Permit:	TBD
Baseline Period:		to	

	Affected or Modified Facilities[2]		Permit No.	Actual Emissions[3]	A	B	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
	FIN	EPN			Baseline Emissions[4]	Proposed Emissions[5]				
1	CC-101	STK-101	TBD		0.0	1,256,845		1,256,845		1,256,845
2	CC-102	STK-102	TBD		0.0	1,256,845		1,256,845		1,256,845
3	ABL-100	ABLSTK-100	TBD		0.0	7,439		7,439		7,439
4	EGEN-100	EGENSTK-100	TBD		0.0	77		77		77
5	FWP-100	FWPSTK-100	TBD		0.0	35		35		35
6	FUGNG-100	FUGNG-100	TBD		0.0	876		876		876
7	SF6-100	SF6-100	TBD		0.0	4.3		4.3		4.3
8										
9										
									Page Subtotal[9]	2,522,122

[1] Individual Table 2F's should be used to summarize the project emission increase for each criteria pollutant
[2] Emission Point Number as designated in NSR Permit or Emissions Inventory
[3] All records and calculations for these values must be available upon request
[4] Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement
[5] If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement
[6] Proposed Emissions (column B) minus Baseline Emissions (column A)
[7] Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement
[8] Obtained by subtracting the correction from the difference. Must be a positive number.
[9] Sum all values for this page.

TABLE 3F
PROJECT CONTEMPORANEOUS CHANGES[1]

Company: Lon C. Hill, LP	
Permit Application Number: TBD	**Criteria Pollutant:** $CO2_e$

Project Date[2]		Facility at Which Emission Change Occurred[3] FIN	EPN	Permit No.	Project Name or Activity	Baseline Period (years)	A Proposed Emissions (tons/year)[4]	B Baseline Emissions (tons/year)[5]	Difference (A-B)[6]	Creditable Decrease or Increase[7]
1	TBD	CC-101	STK-101	TBD	Unit 101 Combined Cycle (GT+HRSG)	NA	1,256,845	0.0	1,256,845	1,256,845
2	TBD	CC-102	STK-102	TBD	Unit 102 Combined Cycle (GT+HRSG)	NA	1,256,845	0.0	1,256,845	1,256,845
3	TBD	ABL-100	ABLSTK-100	TBD	Auxiliary Boiler	NA	7,439	0.0	7,439	7,439
4	TBD	EGEN-100	EGENSTK-100	TBD	Emergency Generator	NA	77	0.0	77	77
5	TBD	FWP-100	FWPSTK-100	TBD	Firewater Pump	NA	35	0.0	35	35
6	TBD	FUGNG-100	FUGNG-100	TBD	Fugitive GHG	NA	876	0.0	876	876
7	TBD	SF6-100	SF6-100	TBD	Electrical Equipment Insulation Leaks	NA	4.3	0.0	4.3	4.3
8										
9										
						Page Subtotal[8]	**2,522,122**	**0.0**	**2,522,122**	**2,522,122**
						Summary of Contemporaneous Changes Total	**2,522,122**	**0.0**	**2,522,122**	**2,522,122**

[1] Individual Table 3F's should be used to summarize the project emission increase and net emission increase for each criteria pollutant.
[2] The start of operation date for the modified or new facilities. Attach Table 4F for each project reduction claimed.
[3] Emission Point No. as designated in NSR Permit or Emissions Inventory.
[4] All records and calculations for these values must be available upon request.
[5] All records and calculations for these values must be available upon request.
[6] Proposed (column A) - Baseline (column B).
[7] If portion of the decrease not creditable, enter creditable amount.
[8] Sum all values for this page.

Attachment B
Emission Rate Calculations

LON C HILL REDEVELOPMENT PROJECT
LON C. HILL, LP

Summary of GHG and CO_2 Sitewide Emission Rates

EPN	FIN	Name	GHG Mass Basis		CO_2e Emission Rate (tpy)
			Pollutant	Emission Rate (tpy)	
STK-101	CC-101	Unit 101 Combined Cycle (GT+HRSG)	CO_2	1,255,634	1,256,845
			CH_4	23.30	
			N_2O	2.33	
STK-102	CC-102	Unit 102 Combined Cycle (GT+HRSG)	CO_2	1,255,634	1,256,845
			CH_4	23.30	
			N_2O	2.33	
ABLSTK-100	ABL-100	Auxiliary Boiler	CO_2	7,432	7,439
			CH_4	0.14	
			N_2O	0.01	
EGENSTK-100	EGEN-100	Emergency Generator	CO_2	76.47	76.73
			CH_4	0.003	
			N_2O	0.001	
FWPSTK-100	FWP-100	Firewater Pump	CO_2	35.21	35.33
			CH_4	0.001	
			N_2O	0.0003	
FUGNG-100	FUGNG-100	Fugitive GHG	CH_4	41.71	876
SF6-100	SF6-100	Electrical Equipment Insulation Leaks	SF_6	0.0002	4.35
Total Sitewide Emission Rates				**2,518,904**	**2,522,122**

LON C HILL REDEVELOPMENT PROJECT
LON C. HILL, LP

GHG Emission Rates per Unit Summary Table

Air Pollutant	Emission Factor (lb/MMBtu)(1), (2)	Heat Rate (HHV) (MMBtu/yr)(3)	GHG Emission Rate (tpy)(4)	Global Warming Potential (100yr.)(5)	CO_2e Emission Rate (tpy)(6)
CO_2	118.8	21,136,220	1,255,634	1	1,255,634
CH_4	2.2E-03		23.30	21	489.27
N_2O	2.2E-04		2.33	310	722.25

Total GHG per Unit(7)	**1,255,659 tpy**
Total CO_2e per Unit(8)	**1,256,845 tpy**

Notes:

(1) CO_2 emission factor calculated per 40 CFR Part 75, Appendix G, Equation G-4, as referenced in §98.43(a), where:
CO2 Emission Factor = 1,040 scf/MMBtu / 385scf/lbmole * 44lb/lbmole = 118.8 lb/MMBtu
Carbon based F-factor, F_C: 1,040
Standard Molar Volume: 385
Molecular Weight CO_2, MW_{CO2}: 44

(2) CH_4 and N_2O emission factors per 40 CFR 98, Subpart C, Table C-2 for natural gas fired units.
CH4 Emission Factor = 1.0E-03 kg/MMBtu * 1 metric ton/1,000 kg * 1.1023 short ton / metric ton * 2,000 lb/short ton = 2.2E-03 lb/MMBtu
N2O Emission Factor = 1.0E-04 kg/MMBtu * 1 metric ton/1,000 kg * 1.1023 short ton / metric ton * 2,000 lb/short ton = 2.2E-04 lb/MMBtu
Where 1.1023 short ton/metric ton per 40 CFR 98, Subpart D, §98.43(a)(1)

(3) Heat Rate (HHV) maximum annual heat rate for all operating scenarios evaluated for both Siemens SCC6-5000F and GE S207FA.04.

(4) Emission Rate = Emission Factor * Heat Rate
CO2 Emission Rate = 118.8 lb/MMBtu * 21,136,220 MMBtu/yr * 1ton/2,000 lb = 1,255,634 tpy

(5) Global Warming potential per 40 CFR 98, Subpart A, Table A-1

(6) CO_2e (tpy) = Mass Emission Rate (tpy) * Global Warming Potential
CH4 as CO2e = 23.30 tpy * 21 = 489.27 tpy

(7) Total GHG emission rate per unit = Sum of GHG mass emission rates
Total GHG = 1,255,634 + 23.30 + 2.33 = 1,255,659 tpy

(8) Total CO2e emission rate per unit = Sum of CO2e emission rates
Total CO2e = 1,255,634 + 489.27 + 722.25 = 1,256,845 tpy

LON C HILL REDEVELOPMENT PROJECT
LON C. HILL, LP

Auxiliary Boiler GHG Emission Rates Summary Table

Air Pollutant	Emission Factor (kg/MMBtu)[(1),(2)]	Heat Rate (HHV) (MMBtu/yr)[(3)]	GHG Emission Rate (tpy)[(4)]	Global Warming Potential (100yr.)[(5)]	CO_2e Emission Rate (tpy)[(6)]
CO_2	53.02	127,161	7,432	1	7,432
CH_4	1.0E-03		0.14	21	2.94
N_2O	1.0E-04		0.01	310	4.35

Total GHG [(7)]	**7,432 tpy**
Total CO_2e [(8)]	**7,439 tpy**

Notes:

(1) CO_2 emission factor per 40 CFR 98, Subpart C, Table C-1 for natural gas fired units.

(2) CH_4 and N_2O emission factors per 40 CFR 98, Subpart C, Table C-2 for natural gas fired units.

(3) Heat Rate (HHV) (MMBtu/yr) = Desing Heat Rate (MMBtu/hr) * Annual Hours of Operation (hr/yr)
#REF!

(4) Emission Rate (tpy) = Emission Factor (kg/MMBtu) * Heat Rate (MMBtu/yr) * 1 metric ton/1,000kg * 1.1023 short ton/metric ton
CH4 Emission Rate = 0.001 kg/MMBtu * 127,161 MMBtu/yr * 1 metric ton/1,000kg * 1.1023 short ton/metric ton = 0.14 tpy
Where 1.1023 short ton/metric ton per 40 CFR 98, Subpart D, §98.43(a)(1)

(5) Global Warming potential per 40 CFR 98, Subpart A, Table A-1

(6) CO_2e (tpy) = Emission Rate (tpy) * Global Warming Potential
CH4 as CO2e = 0.14 tpy * 21 = 2.9 tpy

(7) Total GHG emission rate = Sum of GHG emission rates
Total GHG = 7,432 + 0.14 + 0.01 = 7,432 tpy

(8) Total CO_2e emission rate = Sum of CO2e emission rates
Total CO2e = 7,432 + 2.94 + 4.35 = 7,439 tpy

LON C HILL REDEVELOPMENT PROJECT
LON C. HILL, LP

Emergency Generator GHG Emission Rates Summary Table

Air Pollutant	Emission Factor (kg/MMBtu)[(1),(2)]	Heat Rate (HHV) (MMBtu/yr)[(3)]	GHG Emission Rate (tpy)[(4)]	Global Warming Potential (100yr.)[(5)]	CO_2e Emission Rate (tpy)[(6)]
CO_2	73.96	938	76.47	1	76.5
CH_4	3.0E-03		0.003	21	0.07
N_2O	6.0E-04		0.001	310	0.19

Total GHG [(7)]	**76 tpy**
Total CO_2e [(8)]	**77 tpy**

Notes:

(1) CO_2 emission factors per 40 CFR 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2

(2) CH_4 and N_2O emission factors per 40 CFR 98, Subpart C, Table C-2 for Petroleum (all fuel types in Table C-1)

(3) Heat Rate based on engineering knowledge.

(4) Emission Rate (tpy) = Emission Factor (kg/MMBtu) * Heat Rate (MMBtu/yr) * 1 metric ton/1,000kg * 1.1023 short ton/metric ton
CH4 Emission Rate = 0.003 kg/MMBtu * 938 MMBtu/yr * 1 metric ton/1,000kg * 1.1023 short ton/metric ton = 0.003 tpy
Where 1.1023 short ton/metric ton per 40 CFR 98, Subpart D, §98.43(a)(1)

(5) Global Warming potential per 40 CFR 98, Subpart A, Table A-1

(6) CO_2e (tpy) = Emission Rate (tpy) * Global Warming Potential
CH4 as CO2e = 0.003 tpy * 21 = 0.1 tpy

(7) Total GHG emission rate = Sum of GHG emission rates
Total GHG = 76.5 + 0.003 + 0.001 = 76 tpy

(8) Total CO2e emission rate = Sum of CO2e emission rates
Total CO2e = 76.5 + 0.07 + 0.19 = 77 tpy

LON C HILL REDEVELOPMENT PROJECT
LON C. HILL, LP

Firewater Pump GHG Emission Rates Summary Table

Air Pollutant	Emission Factor (kg/MMBtu)(1),(2)	Heat Rate (HHV) (MMBtu/yr)(3)	GHG Mass Emission Rate (tpy)(4)	Global Warming Potential (100yr.)(5)	CO_2e Emission Rate (tpy)(6)
CO_2	73.96	431.90	35.21	1	35.2
CH_4	3.0E-03		0.001	21	0.03
N_2O	6.0E-04		0.0003	310	0.09

Total GHG (7)	**35 tpy**
Total CO_2e (8)	**35 tpy**

Notes:

(1) CO_2 emission factors per 40 CFR 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2

(2) CH_4 and N_2O emission factors per 40 CFR 98, Subpart C, Table C-2 for Petroleum (all fuel types in Table C-1)

(3) Heat Rate based on engineering knowledge.

(4) Emission Rate (tpy) = Emission Factor (kg/MMBtu) * Heat Rate (MMBtu/yr) * 1 metric ton/1,000kg * 1.1023 short ton/metric ton
CH4 Emission Rate = 0.003 kg/MMBtu * 432 MMBtu/yr * 1 metric ton/1,000kg * 1.1023 short ton/metric ton = 0.001 tpy
Where 1.1023 short ton/metric ton per 40 CFR 98, Subpart D, §98.43(a)(1)

(5) Global Warming potential per 40 CFR 98, Subpart A, Table A-1

(6) CO_2e (tpy) = Emission Rate (tpy) * Global Warming Potential
CH4 as CO2e = 0.001 tpy * 21 = 0.03 tpy

(7) Total GHG emission rate = Sum of GHG emission rates
Total GHG = 35.2 + 0.001 + 0.0003 = 35 tpy

(7) Total CO2e emission rate = Sum of CO2e emission rates
Total CO2e = 35.2 + 0.03 + 0.09 = 35 tpy

LON C HILL REDEVELOPMENT PROJECT
LON C. HILL, LP

Fugitive GHG Emission Rates Summary Table

EPN	Air Pollutant	Weight %(1)	GHG Emission Rate (tpy)(4)	Global Warming Potential (100yr.)(3)	CO_2e Emission Rate (tpy)(4)
FUGNG-100	CH_4	91.84%	41.71	21	876

Notes:

(1) Methane content (in wt%) per fuel analysis.

(2) Annual Emission Rate (tpy) = Service Total Emission Rate (tpy) * CH4 wt%
CH4 Annual Emission Rate = 45.42 tpy * 91.84% = 41.71 tpy

(3) Global Warming potential per 40 CFR 98, Subpart A, Table A-1

(6) CO_2e (tpy) = Emission Rate (tpy) * Global Warming Potential
CH4 as CO2e = 41.71 tpy * 21 = 876 tpy

Natural Gas Service

Component Type	Component Service	Component Count (cpte)(1)	Emission Factor (lb/hr-cpte)(2)	Hours in Service (hr/yr)	Control Efficiency (%)(3)	Max. Hourly Emission Rate (lb/hr)(4)	Annual Emission Rate (tpy)(5)
Valves	Gas/Vapor	520	0.0089	8,760	0.0%	4.63	20.27
Flanges/Connectors	Gas/Vapor	1460	0.0029	8,760	0.0%	4.23	18.54
Compressors	Gas/Vapor	3	0.5027	8,760	0.0%	1.51	6.61
					Service Total	**10.37**	**45.42**

Notes:

(1) Component counts are based on preliminary design information and account for the 2 combined cycle units.

(2) "SOCMI without ethylene" factors.

(3) No control efficiency is claimed for natural gas service.

(3) Max. Hourly Emission Rate (lb/hr) = Component Count (cpte) * Emission Factor (lb/hr-cpte) * (1 - Control Eff%)
Max. Hourly Emission Rate Valves in NG Service = 520 cpte * 0.0089 lb/hr-cpte * (1 - 0.0%) = 4.63 lb/hr

(4) Annual Emission Rate (tpy) = Max. Hourly Emission Rate (lb/hr) * Hours in Service (hr/yr) * 1ton,2,000lb
Annual Emission Rate Valves in NG Service = 4.63 lb/hr * 8,760 hr/yr * 1ton/2,000lb = 20.27 tpy

LON C HILL REDEVELOPMENT PROJECT
LON C. HILL, LP

Electrical Equipment Insulation SF_6 Leaks Emission Rates Summary Table

EPN	Air Pollutant	GHG Emission Rate (tpy)(4)	Global Warming Potential (100yr.)(2)	CO_2e Emission Rate (tpy)(3)
SF6-100	SF_6	1.82E-04	23,900	4.35

Notes:
(1) Annual SF6 Emission Rate (tpy) = Sum [SF_6 Gas Hold by CB * Annual Leak Rate (%/yr)] * 1ton/2,000lb
Annual SF6 Emission Rate = [2GT * 24.25 lb/GT * 0.50% + 1 ST * 24.25 lb/ST * 0.50%] * 1 ton/2,000 lb = 1.82E-04 tpy
(2) Global Warming potential per 40 CFR 98, Subpart A, Table A-1
(3) CO_2e (tpy) = Emission Rate (tpy) * Global Warming Potential
SF6 as CO2e = 18.19E-05 tpy * 23,900 = 4.35 tpy

Electrical Equipment Characteristics

	GT Breakers	ST Breakers
No. of Breakers	2	1
GT Breaker Type(1)	TBD	TBD
GT Operating Mechanism(1)	TBD	TBD
SF_6 Gas Hold by GCB(1)	24.25 lb	24.25 lb
Annual Leak Rate(2)	0.50%	0.50%

Notes:
(1) Per Circuit Breaker Vendor's Specifications
(2) IEC Standard for new equipment leakage, as published on "SF_6 Leak Rates from High Voltage Circuit Breakers" U.S. EPA Investigates Potential Greenhouse Gas Emission Sources" (J. Blackman, et al.)

LON C HILL REDEVELOPMENT PROJECT
LON C. HILL, LP

Natural Gas Fuel Analysis

Compound	Formula	MW (lb/lbmole)	Raw mol%	Normalized mol%	Weight %	Hydrocarbons Pseudo-Formula	
						# C x mol%	#H x mol%
Nitrogen	N2	28.0	0.22	0.22	0.37	-	-
Carbon Dioxide	CO2	44.0	0.71	0.71	1.86	-	-
Methane	CH4	16.0	95.97	95.97	91.84	0.96	3.84
Ethane	C2H6	30.1	2.82	2.81	5.05	0.06	0.17
Propane	C3H8	44.1	0.18	0.18	0.48	0.005	0.01
i-Butane	i-C4H10	58.1	0.03	0.03	0.12	0.001	0.003
n-Butante	n-C4H10	58.1	0.03	0.03	0.10	0.001	0.003
i-Pentane	i-C5H12	72.1	0.01	0.01	0.04	0.0005	0.001
n-Pentane	n-C5H12	72.1	0.01	0.01	0.03	0.0003	0.001
n-Hexane	n-C6H14	86.2	0.01	0.01	0.05	0.0005	0.001
n-Heptane	n-C7H16	100.2	0.01	0.01	0.04	0.0005	0.001
n-Octane	n-C8H18	114.2	0.003	0.003	0.02	0.0003	0.001
	Total	**16.77**	**100.00**	**100.00**	**100.00**	**1.03**	**4.03**

Notes:
1. Composition per Siemens Performance Data.

Attachment C
RBLC Database Search

LON C HILL REDEVELOPMENT PROJECT
LON C. HILL, LP

RACT/BACT/LAER Clearinghouse Data Search for Combined Cycle Combustion Turbines GHG

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	EPA REGION	FACILITY DESCRIPTION	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME
*CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	CA	9	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	COMBUSTION TURBINES (NORMAL OPERATION)	NATURAL GAS	154	MW	Carbon Dioxide Equivalent (CO2e)		774	LB/MW-HR	365-DAY ROLLING AVG (FACILITY WIDE)
*DE-0023	NRG ENERGY CENTER DOVER	NRG ENERGY CENTER DOVER LLC	DE	3	The facility operates two electric generation units and an auxilliiary steam boiler.	UNIT 2- KD1	Natural Gas	655	MMBTU/hr	Carbon Dioxide Equivalent (CO2e)		1085	LBS/GROSS MWH	12 MONTH ROLLING AVERAGE
*DE-0024	GARRISON ENERGY CENTER	GARRISON ENERGY CENTER, LLC/ CALPINE CORPORATION	DE	3	one (1) 309 MW GE Combined Cycle Combustion Turbine Generating system fired principally on Natural Gas, one (1) 86,000 GPM Cooling Tower, one (1) 1,400,000 ULSD Storage Tank	Unit 1	Natural Gas	2260	million BTUs	Carbon Dioxide Equivalent (CO2e)	Fuel Usage Restriction to natural gas and low sulfur distillate fuel	1006304	TONS	12 MONTH ROLLING AVERAGE
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	5	STATIONARY ELECTRIC UTILITY GENERATING STATION	FOUR (4) NATURAL GAS COMBINED CYCLE COMBUSTION	NATURAL GAS	2300	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	HIGH THERMAL EFFICIENCY DESIGN	7646	BTU/KW-H	
LA-0256	COGENERATION PLANT	WESTLAKE VINYLS COMPANY LP	LA	6	COGENERATION PLANT AT SYNTHETIC ORGANIC CHEMICAL MANUFACTURING FACILITY	COGENERATION TRAINS 1-3 (1-10, 2-10, 3-10)	NATURAL GAS	475	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION	55576.77	LB/H	HOURLY MAXIMUM
LA-0257	SABINE PASS LNG TERMINAL	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	LA	6	A liquefaction section of the terminal which will include 24 compressor turbines, two generator turbines, two generator engines, flares, acid gas vents, and fugitives	Combined Cycle Refrigeration Compressor Turbines (8)	natural gas	286	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Good combustion/operating practices and fueled by natural gas - use GE LM2500+G4 turbines	4872107	TONS/YEAR	ANNUAL MAXIMUM FROM THE FACILITYWIDE
*MI-0402	SUMPTER POWER PLANT	WOLVERINE POWER SUPPLY COOPERATIVE INC.	MI	5	Utility--Natural gas fired combustion turbine	Combined cycle combustion turbine w/ HRSG	Natural gas	130	MW electrical output	Carbon Dioxide Equivalent (CO2e)		954	LB/MW-H	12-MONTH ROLLING AVERAGE
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	5	799 Megawatt Combined Cycle Combustion Turbine Power Plant	2 Combined Cycle Combustion Turbines-Siemens, without duct burners	Natural Gas	515600	MMSCF/rolling 12-months	Carbon Dioxide Equivalent (CO2e)	state-of-the-art high efficiency combustion technology	318404	LB/H	
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	5	799 Megawatt Combined Cycle Combustion Turbine Power Plant	2 Combined Cycle Combustion Turbines-Siemens, with duct burners	Natural Gas	51560	MMSCF/rolling 12-MO	Carbon Dioxide Equivalent (CO2e)	state-of-the-art high efficiency combustion technology	318404	LB/H	
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	5	799 Megawatt Combined Cycle Combustion Turbine Power Plant	2 Combined Cycle Combustion Turbines-Mitsubishi, without duct burners	Natural Gas	47917	MMSCF/rolling 12-MO	Carbon Dioxide Equivalent (CO2e)	state-of-the-art high efficiency combustion technology	318404	LB/H	
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	5	799 Megawatt Combined Cycle Combustion Turbine Power Plant	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	Natural Gas	47917	MMSCF/rolling 12-MO	Carbon Dioxide Equivalent (CO2e)	state-of-the-art high efficiency combustion technology	318404	LB/H	

RACT/BACT/LAER Clearinghouse Data Search for Combined Cycle Combustion Turbines GHG

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	EPA REGION	FACILITY DESCRIPTION	PROCESS NAME	PRIMARY FUEL	THROUGH PUT	THROUGH PUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME
*PA-0291	HICKORY RUN ENERGY STATION	HICKORY RUN ENERGY LLC	PA	3	Natural gas-fired combined-cycle electric generation facility that is designed to generate up to 900 MW nominal, using 2 combustion turbine generators and 2 heat recovery steam generators that will provide steam to drive a single steam turbine generator. Each heat recovery steam generator will be equipped with a duct burner which may be utilized at time of peak power demands to supplement power output. The project will also include a natural gasfired auxiliary boiler; a diesel engine-driven emergency generator; a diesel engine-driven firewater pump; a multi-cell evaporative cooling tower; and associated emission control systems, tanks, and other balance of plant equipment.	COMBINED CYCLE UNITS #1 and #2	Natural Gas	3.4	MMCF/HR	Carbon Dioxide Equivalent (CO2e)		3665974	TPY	12-MONTH ROLLING TOTAL FOR BOTH UNITS
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	6	Install 2 new natural gas-fired combined-cycle combustion turbine units (U1-STKand U2-STK) with a generating capacity of approximately 590 MW. The steam produced from the two new combustion turbines will exhaust to two dedicated Heat Recovery Steam Generators (HRSG) to produce steam. The steam produced from the two HRSGs is routed to the new shared steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid.	COMBINED CYCLE TURBINE GENERATOR U1-STK	Natural Gas	1746	MMBTU/H	Methane		16.8	T/YR	365-DAY ROLLING AVERAGE
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	6	Install 2 new natural gas-fired combined-cycle combustion turbine units (U1-STKand U2-STK) with a generating capacity of approximately 590 MW. The steam produced from the two new combustion turbines will exhaust to two dedicated Heat Recovery Steam Generators (HRSG) to produce steam. The steam produced from the two HRSGs is routed to the new shared steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid.	COMBINED CYCLE TURBINE GENERATOR U1-STK	Natural Gas	1746	MMBTU/H	Nitrous Oxide (N2O)		1.7	T/YR	360 DAY ROLLING AVERAGE

RACT/BACT/LAER Clearinghouse Data Search for Combined Cycle Combustion Turbines GHG

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	EPA REGION	FACILITY DESCRIPTION	PROCESS NAME	PRIMARY FUEL	THROUGH PUT	THROUGH PUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	6	Install 2 new natural gas-fired combined-cycle combustion turbine units (U1-STKand U2-STK) with a generating capacity of approximately 590 MW. The steam produced from the two new combustion turbines will exhaust to two dedicated Heat Recovery Steam Generators (HRSG) to produce steam. The steam produced from the two HRSGs is routed to the new shared steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid.	COMBINED CYCLE TURBINE GENERATOR U1-STK	Natural Gas	1746	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Good Combustion Practices	908957.6	LB/H	30-DAY ROLLING AVERAGE
*TX-0632	DEER PARK ENERGY CENTER LLC	CALPIINE CO - DEER PARK ENERGY CENTER(DPEC) LLC	TX	6	DPEC plant proposes phased construction of the natural gas-fired combined-cycle CTG with a generating capacity of approximately 180 megawatts that will be completed in two stages of construction. In the initial phase - Calpine intends to construct a Siemens Model FD2 combustion turbine. In the second Phase - Siemens Model FD2 combustion turbine will be upgraded in performance as a FD3-series combustion turbine.	CTG5/HRSG5(FD3-Series)	Natural Gas	0		Methane		19.67	T/YR	365-DAY ROLLING AVERAGE
*TX-0632	DEER PARK ENERGY CENTER LLC	CALPIINE CO - DEER PARK ENERGY CENTER(DPEC) LLC	TX	6	DPEC plant proposes phased construction of the natural gas-fired combined-cycle CTG with a generating capacity of approximately 180 megawatts that will be completed in two stages of construction. In the initial phase - Calpine intends to construct a Siemens Model FD2 combustion turbine. In the second Phase - Siemens Model FD2 combustion turbine will be upgraded in performance as a FD3-series combustion turbine.	CTG5/HRSG5(FD3-Series)	Natural Gas	0		Nitrous Oxide (N2O)		1.97	T/YR	365-DAY ROLLING AVERAGE
*TX-0632	DEER PARK ENERGY CENTER LLC	CALPIINE CO - DEER PARK ENERGY CENTER(DPEC) LLC	TX	6	DPEC plant proposes phased construction of the natural gas-fired combined-cycle CTG with a generating capacity of approximately 180 megawatts that will be completed in two stages of construction. In the initial phase - Calpine intends to construct a Siemens Model FD2 combustion turbine. In the second Phase - Siemens Model FD2 combustion turbine will be upgraded in performance as a FD3-series combustion turbine.	CTG5/HRSG5(FD3-Series)	Natural Gas	0		Carbon Dioxide		1062627	T/YR	365-DAY ROLLING AVERAGE

RACT/BACT/LAER Clearinghouse Data Search for Combined Cycle Combustion Turbines GHG

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	EPA REGION	FACILITY DESCRIPTION	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME
*TX-0632	DEER PARK ENERGY CENTER LLC	CALPIINE CO - DEER PARK ENERGY CENTER(DPEC) LLC	TX	6	DPEC plant proposes phased construction of the natural gas-fired combined-cycle CTG with a generating capacity of approximately 180 megawatts that will be completed in two stages of construction. In the initial phase - Calpine intends to construct a Siemens Model FD2 combustion turbine. In the second Phase - Siemens Model FD2 combustion turbine will be upgraded in performance as a FD3-series combustion turbine.	CTG5/ HRSG5 (FD2-Series)	natural gas	0		Methane		19.34	T/YR	365-DAY ROLLING AVERAGE
*TX-0632	DEER PARK ENERGY CENTER LLC	CALPIINE CO - DEER PARK ENERGY CENTER(DPEC) LLC	TX	6	DPEC plant proposes phased construction of the natural gas-fired combined-cycle CTG with a generating capacity of approximately 180 megawatts that will be completed in two stages of construction. In the initial phase - Calpine intends to construct a Siemens Model FD2 combustion turbine. In the second Phase - Siemens Model FD2 combustion turbine will be upgraded in performance as a FD3-series combustion turbine.	CTG5/ HRSG5 (FD2-Series)	natural gas	0		Nitrous Oxide (N2O)		1.93	T/YR	365-DAY ROLLING AVERAGE
*TX-0632	DEER PARK ENERGY CENTER LLC	CALPIINE CO - DEER PARK ENERGY CENTER(DPEC) LLC	TX	6	DPEC plant proposes phased construction of the natural gas-fired combined-cycle CTG with a generating capacity of approximately 180 megawatts that will be completed in two stages of construction. In the initial phase - Calpine intends to construct a Siemens Model FD2 combustion turbine. In the second Phase - Siemens Model FD2 combustion turbine will be upgraded in performance as a FD3-series combustion turbine.	CTG5/ HRSG5 (FD2-Series)	natural gas	0		Carbon Dioxide		0.46	T/MW-H	30-DAY ROLLING AVERAGE
*VA-0319	GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT	GATEWAY GREEN ENERGY	VA	3	Combined cycle electrical power generating facility (160 MW), consisting of two combustion turbines (Rolls Royce Trent 60 WLE) with associated HRSG and no duct burning.	COMBUSTION TURBINES, (2)	Natural Gas	593	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Controlled by the use of low carbon fuels and high efficiency design. The heat rate shall be no greater than 8,983 Btu/kW-h (HHV, gross).	295961	T/YR	12 MO ROLLING AVG

LON C HILL REDEVELOPMENT PROJECT
LON C. HILL, LP

RACT/BACT/LAER Clearinghouse Data Search for Natural Gas-Fired Auxiliary Boiler GHG

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	EPA REGION	FACILITY DESCRIPTION	PROCESS NAME	PRIMARY FUEL	THROUGH PUT	THROUGH PUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME
*CA-1212	PALMDALE HYBRID POWER	CITY OF PALMDALE	CA	9	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	AUXILIARY BOILER	NATURAL GAS	110	MMBTU/HR	Carbon Dioxide Equivalent (CO2e)	ANNUAL BOILER TUNE-UPS	0		
*CA-1212	PALMDALE HYBRID POWER	CITY OF PALMDALE	CA	9	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	AUXILIARY HEATER	NATURAL GAS	40	MMBTU/HR	Carbon Dioxide Equivalent (CO2e)	ANNUAL BOILER TUNEUPS	0		
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	5	STATIONARY ELECTRIC UTILITY GENERATING STATION	TWO (2) NATURAL GAS AUXILIARY BOILERS	NATURAL GAS	80	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	OPERATION AND MAINTENANCE PRACTICES; COMBUSTION TURNING; OXYGEN TRIM CONTROLS & ANALYZERS; ECONOMIZER; ENERGY EFFICIENT REFRACTORY; CONDENSATE RETURN	81996	TONS	12 CONSECUTIVE MONTH PERIOD
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	5	799 Megawatt Combined Cycle Combustion Turbine Power Plant	Auxillary Boiler	Natural Gas	99	MMBtu/H	Carbon Dioxide Equivalent (CO2e)		11671	T/YR	PER ROLLING 12-MONTHS
*PA-0291	HICKORY RUN ENERGY STATION	HICKORY RUN ENERGY LLC	PA	3	Natural gas-fired combined-cycle electric generation facility that is designed to generate up to 900 MW nominal, using 2 combustion turbine generators and 2 heat recovery steam generators that will provide steam to drive a single steam turbine generator. Each heat recovery steam generator will be equipped with a duct burner which may be utilized at time of peak power demands to supplement power output. The project will also include a natural gasfired auxiliary boiler; a diesel engine-driven emergency generator; a diesel engine-driven firewater pump; a multi-cell evaporative cooling tower; and associated emission control systems, tanks, and other balance of plant equipment.	AUXILIARY BOILER	Natural Gas	40	MMBTU/HR	Carbon Dioxide Equivalent (CO2e)		13696	TPY	12-MONTH ROLLING BASIS

RACT/BACT/LAER Clearinghouse Data Search for Diesel-Fired Emergency Generator GHG

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	EPA REGION	FACILITY DESCRIPTION	PROCESS NAME	PRIMARY FUEL	THROUGH PUT	THROUGH PUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	5	STATIONARY ELECTRIC UTILITY GENERATING STATION	TWO (2) EMERGENCY DIESEL GENERATORS	DIESEL	1006	HP EACH	Carbon Dioxide Equivalent (CO2e)	GOOD ENGINEERING DESIGN AND FUEL EFFICIENT DESIGN	1186	TONS	12 CONSECUTIVE MONTH PERIOD
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	5	STATIONARY ELECTRIC UTILITY GENERATING STATION	EMERGENCY DIESEL GENERATOR	DIESEL	2012	HP	Carbon Dioxide Equivalent (CO2e)	GOOD ENGINEERING DESIGN AND FUEL EFFICIENT DESIGN POST COMBUSTION CARBON CAPTURE	1186	TONS	12 CONSECUTIVE MONTH PERIOD
*MI-0402	SUMPTER POWER PLANT	WOLVERINE POWER SUPPLY COOPERATIVE INC.	MI	5	Utility--Natural gas fired combustion turbine	Diesel fuel-fired combustion engine (RICE)	Diesel	732	HP	Carbon Dioxide Equivalent (CO2e)	Good combustion practices	716.6	LB/H	TEST
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	5	799 Megawatt Combined Cycle Combustion Turbine Power Plant	Emergency generator	diesel	2250	KW	Carbon Dioxide Equivalent (CO2e)		878	T/YR	PER ROLLING 12-MONTHS
*PA-0291	HICKORY RUN ENERGY STATION	HICKORY RUN ENERGY LLC	PA	3	Natural gas-fired combined-cycle electric generation facility that is designed to generate up to 900 MW nominal, using 2 combustion turbine generators and 2 heat recovery steam generators that will provide steam to drive a single steam turbine generator. Each heat recovery steam generator will be equipped with a duct burner which may be utilized at time of peak power demands to supplement power output. The project will also include a natural gasfired auxiliary boiler; a diesel engine-driven emergency generator; a diesel engine-driven firewater pump; a multi-cell evaporative cooling tower; and associated emission control systems, tanks, and other balance of plant equipment.	EMERGENCY GENERATOR	Ultra Low sulfur Distillate	7.8	MMBTU/HR	Carbon Dioxide Equivalent (CO2e)		80.5	TPY	12-MONTH ROLLING BASIS
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	6	Install 2 new natural gas-fired combined-cycle combustion turbine units (U1-STKand U2-STK) with a generating capacity of approximately 590 MW. The steam produced from the two new combustion turbines will exhaust to two dedicated Heat Recovery Steam Generators (HRSG) to produce steam. The steam produced from the two HRSGs is routed to the new shared steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid.	EMGEN1-STK - DIESEL FIRED EMERGENCY GENERATOR	DIESEL	93.8		Carbon Dioxide Equivalent (CO2e)		15314	LB/H	30-DAY ROLLING AVERAGE

RACT/BACT/LAER Clearinghouse Data Search for Diesel-Fired Emergency Generator GHG

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	EPA REGION	FACILITY DESCRIPTION	PROCESS NAME	PRIMARY FUEL	THROUGH PUT	THROUGH PUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	6	Install 2 new natural gas-fired combined-cycle combustion turbine units (U1-STKand U2-STK) with a generating capacity of approximately 590 MW. The steam produced from the two new combustion turbines will exhaust to two dedicated Heat Recovery Steam Generators (HRSG) to produce steam. The steam produced from the two HRSGs is routed to the new shared steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid.	EMGEN1-STK - DIESEL FIRED EMERGENCY GENERATOR	DIESEL	93.8		Carbon Dioxide	To fire diesel fuel containing no more than 0.5 percent sulfur by weight.	7027.8	LB/H	30 DAY ROLLING AVERAGE

RACT/BACT/LAER Clearinghouse Data Search for Firewater Pump Diesel Engine GHG

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	EPA REGION	FACILITY DESCRIPTION	PROCESS NAME	PRIMARY FUEL	THROUGH PUT	THROUGH PUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	5	STATIONARY ELECTRIC UTILITY GENERATING STATION	TWO (2) FIREWATER PUMP DIESEL ENGINES	DIESEL	371	BHP EACH	Carbon Dioxide Equivalent (CO2e)	GOOD ENGINEERING DESIGN AND FUEL EFFICIENT DESIGN	172	TONS	12 CONSECUTIVE MONTH PERIOD
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	OH	5	799 Megawatt Combined Cycle Combustion Turbine Power Plant	Emergency fire pump engine	diesel	300	HP	Carbon Dioxide Equivalent (CO2e)		87	T/YR	PER ROLLING 12-MONTHS
*PA-0291	HICKORY RUN ENERGY STATION	HICKORY RUN ENERGY LLC	PA	3	Natural gas-fired combined-cycle electric generation facility that is designed to generate up to 900 MW nominal, using 2 combustion turbine generators and 2 heat recovery steam generators that will provide steam to drive a single steam turbine generator. Each heat recovery steam generator will be equipped with a duct burner which may be utilized at time of peak power demands to supplement power output. The project will also include a natural gasfired auxiliary boiler; a diesel engine-driven emergency generator; a diesel engine-driven firewater pump; a multi-cell evaporative cooling tower; and associated emission control systems, tanks, and other balance of plant equipment.	EMERGENCY FIREWATER PUMP	ULTRA LOW SULFUR DISTILLATE	3.25	MMBTU/HR	Carbon Dioxide Equivalent (CO2e)		33.8	TPY	12-MONTH ROLLING BASIS
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	6	Install 2 new natural gas-fired combined-cycle combustion turbine units (U1-STKand U2-STK) with a generating capacity of approximately 590 MW. The steam produced from the two new combustion turbines will exhaust to two dedicated Heat Recovery Steam Generators (HRSG) to produce steam. The steam produced from the two HRSGs is routed to the new shared steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid.	FWP1-STK DIESEL FIRED FIRE WATER PUMP	DIESEL	617	HP	Carbon Dioxide Equivalent (CO2e)	Best Work practice	7027.8	LB/H	30-DAY ROLLING AVERAGE
*VA-0319	GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT	GATEWAY GREEN ENERGY	VA	3	Combined cycle electrical power generating facility (160 MW), consisting of two combusion turbines (Rolls Royce Trent 60 WLE) with associated HRSG and no duct burning.	FIRE WATER PUMP	diesel (ultra low sulfur)	1.86	MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Fuel-efficient design	30.5	T/YR	12 MO ROLLING AVG

RACT/BACT/LAER Clearinghouse Data Search for Fugitive Natural Gas Service GHG

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	EPA REGION	FACILITY DESCRIPTION	PROCESS NAME	PRIMARY FUEL	THROUGH PUT	THROUGH PUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	6	Install 2 new natural gas-fired combined-cycle combustion turbine units (U1-STKand U2-STK) with a generating capacity of approximately 590 MW. The steam produced from the two new combustion turbines will exhaust to two dedicated Heat Recovery Steam Generators (HRSG) to produce steam. The steam produced from the two HRSGs is routed to the new shared steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid.	Fugitive Natural Gas emissions_NG-FUG	Natural Gas	0		Methane		16.2	T/YR	
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	6	Install 2 new natural gas-fired combined-cycle combustion turbine units (U1-STKand U2-STK) with a generating capacity of approximately 590 MW. The steam produced from the two new combustion turbines will exhaust to two dedicated Heat Recovery Steam Generators (HRSG) to produce steam. The steam produced from the two HRSGs is routed to the new shared steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid.	Fugitive Natural Gas emissions_NG-FUG	Natural Gas	0		Carbon Dioxide Equivalent (CO2e)		327.2	T/YR	365-DAY ROLLING AVERAGE
*TX-0632	DEER PARK ENERGY CENTER LLC	CALPIINE CO - DEER PARK ENERGY CENTER(DPEC) LLC	TX	6	DPEC plant proposes phased construction of the natural gas-fired combined-cycle CTG with a generating capacity of approximately 180 megawatts that will be completed in two stages of construction. In the initial phase - Calpine intends to construct a Siemens Model FD2 combustion turbine. In the second Phase - Siemens Model FD2 combustion turbine will be upgraded in performance as a FD3-series combustion turbine.	NG-FUG	Natural Gas	0		Methane		2.84	T/YR	365-DAY ROLLING AVERAGE
*TX-0632	DEER PARK ENERGY CENTER LLC	CALPIINE CO - DEER PARK ENERGY CENTER(DPEC) LLC	TX	6	DPEC plant proposes phased construction of the natural gas-fired combined-cycle CTG with a generating capacity of approximately 180 megawatts that will be completed in two stages of construction. In the initial phase - Calpine intends to construct a Siemens Model FD2 combustion turbine. In the second Phase - Siemens Model FD2 combustion turbine will be upgraded in performance as a FD3-series combustion turbine.	NG-FUG	Natural Gas	0		Carbon Dioxide		0.11	T/YR	365-DAY ROLLING AVERAGE

RACT/BACT/LAER Clearinghouse Data Search for Circuit Breakers GHG

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY STATE	EPA REGION	FACILITY DESCRIPTION	PROCESS NAME	PRIMARY FUEL	THROUGH PUT	THROUGH PUT UNIT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME
*CA-1212	PALMDALE HYBRID POWER	CITY OF PALMDALE	CA	9	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	ENCLOSED PRESSURE SF6 CIRCUIT BREAKERS		0		Carbon Dioxide Equivalent (CO2e)		9.56	TPY	12-MONTH ROLLING TOTAL
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	IN	5	STATIONARY ELECTRIC UTILITY GENERATING STATION	ELECTRICAL CIRCUIT BREAKERS		0		Sulfur Hexafluoride	ALTERNATIVE TECHNOLOGY FULLY ENCLOSED CIRCUIT BREAKERS WITH LEAK DETECTION	0.0009	TONS	12 CONSECUTIVE MONTH PERIOD
*TX-0612	THOMAS C. FERGUSON POWER PLANT	LOWER COLORADO RIVER AUTHORITY	TX	6	Install 2 new natural gas-fired combined-cycle combustion turbine units (U1-STKand U2-STK) with a generating capacity of approximately 590 MW. The steam produced from the two new combustion turbines will exhaust to two dedicated Heat Recovery Steam Generators (HRSG) to produce steam. The steam produced from the two HRSGs is routed to the new shared steam turbine unit to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid.	SF6 Insulated Electric Equipment_SF6-FUG		0		Sulfur Hexafluoride		131	T/YR	365-DAY ROLLING AVERAGE (USE AS CO2E)
*TX-0632	DEER PARK ENERGY CENTER LLC	CALPIINE CO - DEER PARK ENERGY CENTER(DPEC) LLC	TX	6	DPEC plant proposes phased construction of the natural gas-fired combined-cycle CTG with a generating capacity of approximately 180 megawatts that will be completed in two stages of construction. In the initial phase - Calpine intends to construct a Siemens Model FD2 combustion turbine. In the second Phase - Siemens Model FD2 combustion turbine will be upgraded in performance as a FD3-series combustion turbine.	SF6-FUG		0		Sulfur Hexafluoride		0.0002	T/YR	
*VA-0319	GATEWAY COGENERATION 1, LLC - SMART WATER PROJECT	GATEWAY GREEN ENERGY	VA	3	Combined cycle electrical power generating facility (160 MW), consisting of two combustion turbines (Rolls Royce Trent 60 WLE) with associated HRSG and no duct burning.	ELECTRIC CIRCUIT BREAKERS, (4)		60	LB/SF6	Carbon Dioxide Equivalent (CO2e)	Enclosed pressure circuit breaker.	28.6	T/YR	12 MO AVG