PREVENTION OF SIGNIFICANT DETERIORATION GREENHOUSE GAS AIR PERMIT APPLICATION

Indeck Wharton Energy Center
Wharton County, Texas

Submitted to:
Environmental Protection Agency – Region 6
Multimedia Planning and Permitting Division
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ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology
Btu/hr	British thermal unit per hour
Btu/kWhr	British thermal units per kilowatt hour
Btu/lb	British thermal unit per pound
CAA	Clean Air Act
CCCT	Combined cycle combustion turbine
CFR	Code of Federal Regulations
CEMS	Continuous emissions monitoring system
CO	Carbon monoxide
CO_2e	Carbon dioxide equivalent
CT	Combustion turbine
EDG	Emergency diesel generator
EPA	Environmental Protection Agency
ERCOT	Electric Reliability Council of Texas
FP	Fire pump
GCV	Gross calorific value
GWP	Global Warming Potential
HHV	Higher heating value
hp	Horsepower
km	Kilometer
kW	Kilowatt
kWhr	kiloWatt hours
lb/MMBtu	Pound per million British thermal units
lb/hr	Pounds per hour
lb/ton	Pounds per ton
lbs	Pounds
LHV	Lower heating value
m	Meters
MMBtu	Million British thermal units
MMBtu/hr	Million British thermal units per hour
MW	Megawatt
$\mu g/m^3$	Microgram per cubic meter
NAD	North American Datum
NO_2	Nitrogen dioxide
NO_x	Nitrogen oxides
NSPS	New Source Performance Standards
NSR	New Source Review
O_2	Oxygen
PM	Particulate matter
psi	pounds per square inch
PSD	Prevention of significant deterioration

ACRONYMS AND ABBREVIATIONS (Continued)

RBLC	RACT\BACT\LAER Clearinghouse
ton/MWh	Ton per megawatt-hr
SO_2	Sulfur dioxide
SUSD	Startup / shutdown
tpy	Tons per year
UTM	Universal Transverse Mercator
VOC	Volatile organic compound

EXECUTIVE SUMMARY

Indeck Wharton, LLC (Indeck) is proposing to construct the Indeck Wharton Energy Center Project (Project), a natural gas-fired simple cycle combustion turbine (CT) facility southwest of Houston on State Route 71, 0.5 miles south of Danevang in Wharton County, Texas. The Project will consist of three (3) F-Class turbines with a facility-wide gross electric generating capacity of approximately 650 MW. Currently the Project is considering either General Electric or Siemens turbine models.

The proposed emission rates for the Project exceed major new source thresholds for carbon monoxide (CO), nitrogen oxides (NO_x), and carbon dioxide equivalent (CO_2e). The Project will have minor emission increases in sulfur dioxide (SO_2), volatile organic compounds (VOC) and particulate matter (PM). Indeck is in the process of applying with the Texas Commission of Environmental Quality (TCEQ) for a Prevention of Significant Deterioration (PSD) air permit for the facility's criteria pollutant emissions. The PSD air permit application was submitted to TCEQ on June 17, 2013.

The potential greenhouse gas (GHG) emissions for the Project exceed 100,000 tpy CO_2e, and as a result, the GHGs are "subject to regulation" as defined in Federal PSD rules. The Environmental Protection Agency (EPA) promulgated a Federal Implementation Plan (FIP) to implement the permitting requirements for GHGs in Texas and EPA has assumed the role of the permitting authority for Texas GHG permit applications. Therefore, GHG emissions from the proposed facility are subject to the jurisdiction of the EPA through its FIP for the regulation of GHGs. This permit application satisfies GHG air permitting requirements. Since the EPA does not have application forms for GHG permitting, TCEQ application forms were used and are included in Appendix A.

1.0 INTRODUCTION

The Indeck Wharton Energy Center (Project) will be a 650 MW peaking power project. The Project is based on three natural gas-fired "F" class combustion turbines (CT) in simple cycle. It will be classified as a wholesale electric generator selling power into the Electric Reliability Council of Texas (ERCOT) region. In terms of size and demand, ERCOT has a peak load of approximately 68.3 GW (actual 2011). This is slightly larger than the peak load of California and twice the peak load of either New York or New England.

Supply shortages are expected in the next five years within ERCOT. In particular, the Houston region has been identified as the most likely to be affected in this regard. The Project is designed to respond to this potential shortage. In that the electric shortage is forecasted within the near term, a peaking power project such as the Project is ideally suited to respond to this condition. Its shorter construction schedule and favorable operational characteristics would enable the Project to be in operation prior to other power production options and to more fully respond to the perceived need. Other power options such as combined cycle gas turbines or base load steam plants are hampered by longer lead times and less flexible operating parameters. Intermittent renewable projects such as wind and solar are unable to meet the reliability requirements of a peaking project. Options to the selected "F" class turbines, such as internal combustion engines, or different CTs, lack the advantages of the selected technology from either environmental and/or operational characteristics. For these reasons, Indeck is proposing to construct three "F" Class simple cycle CTs at the Wharton site.

To facilitate EPA's review of this document, individuals familiar with both the Project and the preparation of this application are identified below. The EPA should contact these individuals if additional information or clarification is required during the review process. These contacts include the primary contact for the consultant who has assisted with the preparation of this application under the direction of Indeck.

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The permit application is organized into 6 sections, plus appendices.

- Section 1 – Introduction.
- Section 2 – Project description
- Section 3 – GHG Emissions
- Section 4 – Regulatory review and applicability

- Section 5 – BACT analysis
- Section 6 – References
- Appendix A – Application forms
- Appendix B – Emissions calculations

2.0 PROJECT DESCRIPTION

This section is a project summary describing the proposed turbines for the facility.

2.1 Introduction

The Project location is on State Route 71, 0.5 miles south of Danevang in Wharton County, Texas. The region surrounding the site is characterized as rural with sparsely scattered residences. The center of the 154 acre plot is located at Universal Transverse Mercator (UTM NAD83) coordinates 771.460 kilometers (km) east and 4,216.320 km north (Zone 14). A topographical map of the site region is shown in Figure 2-1. A plot plan for the Project is presented in Figure 2-2 and a process flow diagram for the facility is shown in Figure 2-3.

The Project will include the following GHG emission sources:

- Three (3) natural gas fired simple cycle CTs
- One (1) emergency diesel generator
- One (1) diesel fire pump engine
- One (1) gas pipeline heater
- Natural gas piping
- Circuit breaker dielectric insulator

2.2 Simple Cycle Combustion Turbines

The three simple cycle natural gas-fired CTs will be capable of producing a total of approximately 650 MW of gross electric output. At the current time, Indeck is considering either the GE Frame 7FA or the Siemens SGT6 5000F. These units are state-of-the-art combustion gas turbines. They provide very low emissions and high efficiency. The turbines achieve heat rates of 10,000 BTU/kWh (HHV), with low emissions of NOx and CO. This class turbine represents the latest technology for simple cycle applications and is generally considered the most advanced power option for the Project. This application presents GHG emission rates for both manufacturers.

2.3 Emergency Diesel Generator & Diesel Fire Pump

The Project will include an emergency diesel generator (EDG) engine and a diesel fire pump (FP). Both engines will operate on low sulfur (0.05%) diesel fuel. The proposed EDG will be a Caterpiller C18 ATAAC Diesel engine (or equivalent) with a standby generating capacity of 600 ekW. The proposed FP engine will be a Cummins CFP7E-F10 Driver (or equivalent) with a rating of 175 horsepower (hp). Both engines will be used in emergency situations only (with the exception of periodic maintenance/testing events). The EDG will be an EPA-certified Tier 2 engine which will operate a maximum of 500 hrs/yr. The fire pump will meet Tier 3 standards for off-road diesel engines under 40 CFR 89 and operate no more than 300 hours per year. With the exception of emergency situations, the units will typically operate no more than one hour per week, for maintenance purposes. Proposed GHG emission limits for the EDG and FP are shown in Tables 3-5 and 3-6.

2.4 Natural Gas Pipeline Heater

The project will include a 3 MMBtu/hr gas pipeline heater. There are no add-on controls available for small gas-fired emission units such as the proposed pipeline heater. BACT for the pipeline heater includes the fuel (natural gas), good combustion practices (GCP), and an annual operations limit of 3,500 hours/yr which is the annual turbine limit of 2,500 hrs plus 1,000 hours to include startups and shutdowns (SUSD). Based on AP-42 emission factors, the estimated GHG emission rates for the pipeline heater are shown in Table 3-7.

2.5 Natural Gas Piping

Natural gas piping, valves and flanges will be constructed to transport natural gas from the main pipeline to the CTs. Fugitive emissions of methane (CH_4) may be emitted from the piping and associated equipment (flanges, connectors, compressors, etc.). A listing of gas piping components and estimated GHG emission rates is presented in Table 3-8.

2.6 Circuit Breaker Dielectric Insulator

The facility will employ a maximum, worst case scenario of 14 circuit breakers that contain sulfur hexafluoride (SF_6) of which a small amount may leak into the atmosphere. SF_6 is an excellent electrical insulator used for arc quenching and current interruption in high-voltage electrical equipment; however, it is also a powerful GHG. Fugitive SF_6 emissions are shown in Table 3-9.

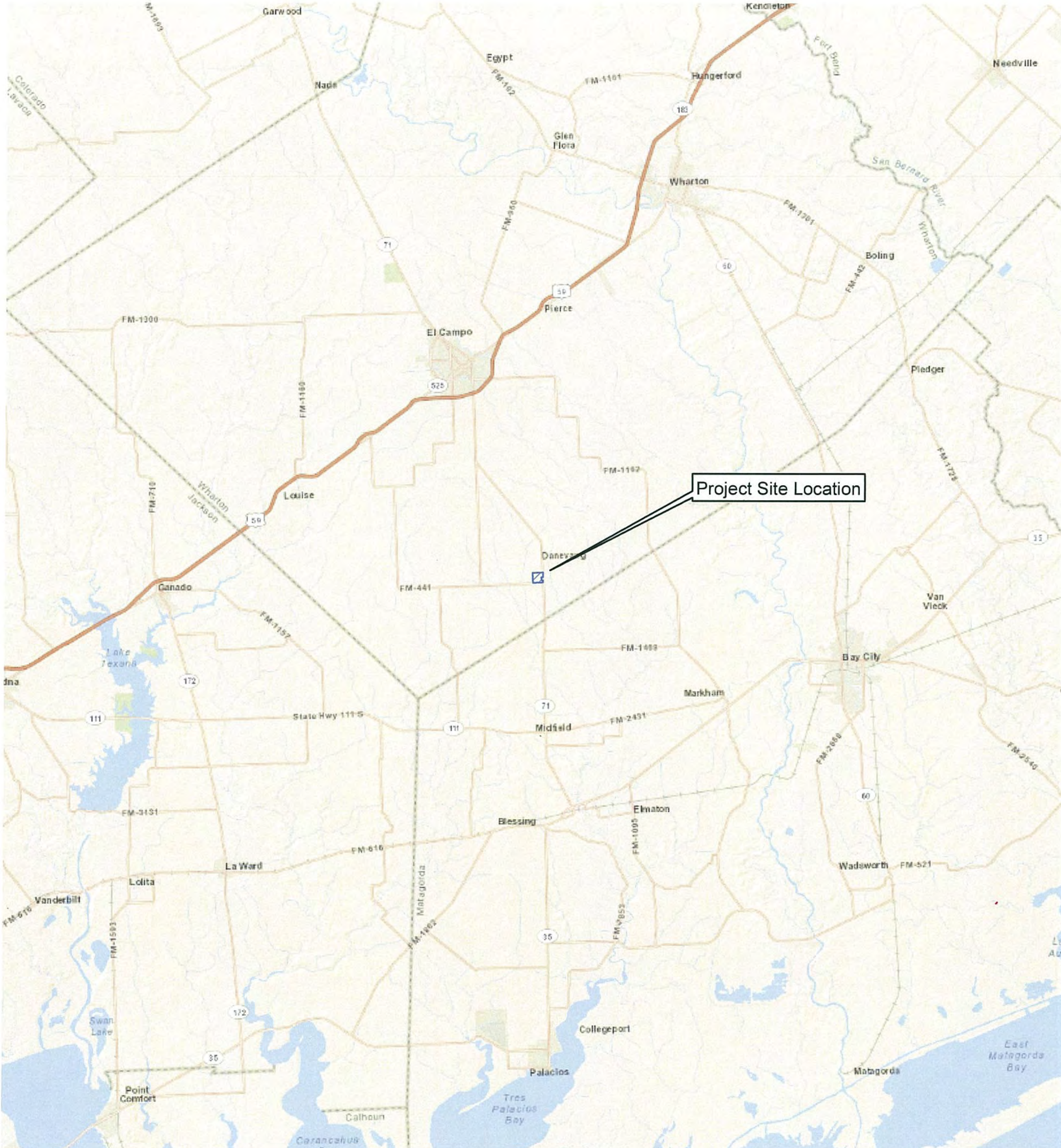


Figure 2-1

General Location Map

Indeck Wharton Energy Center Project

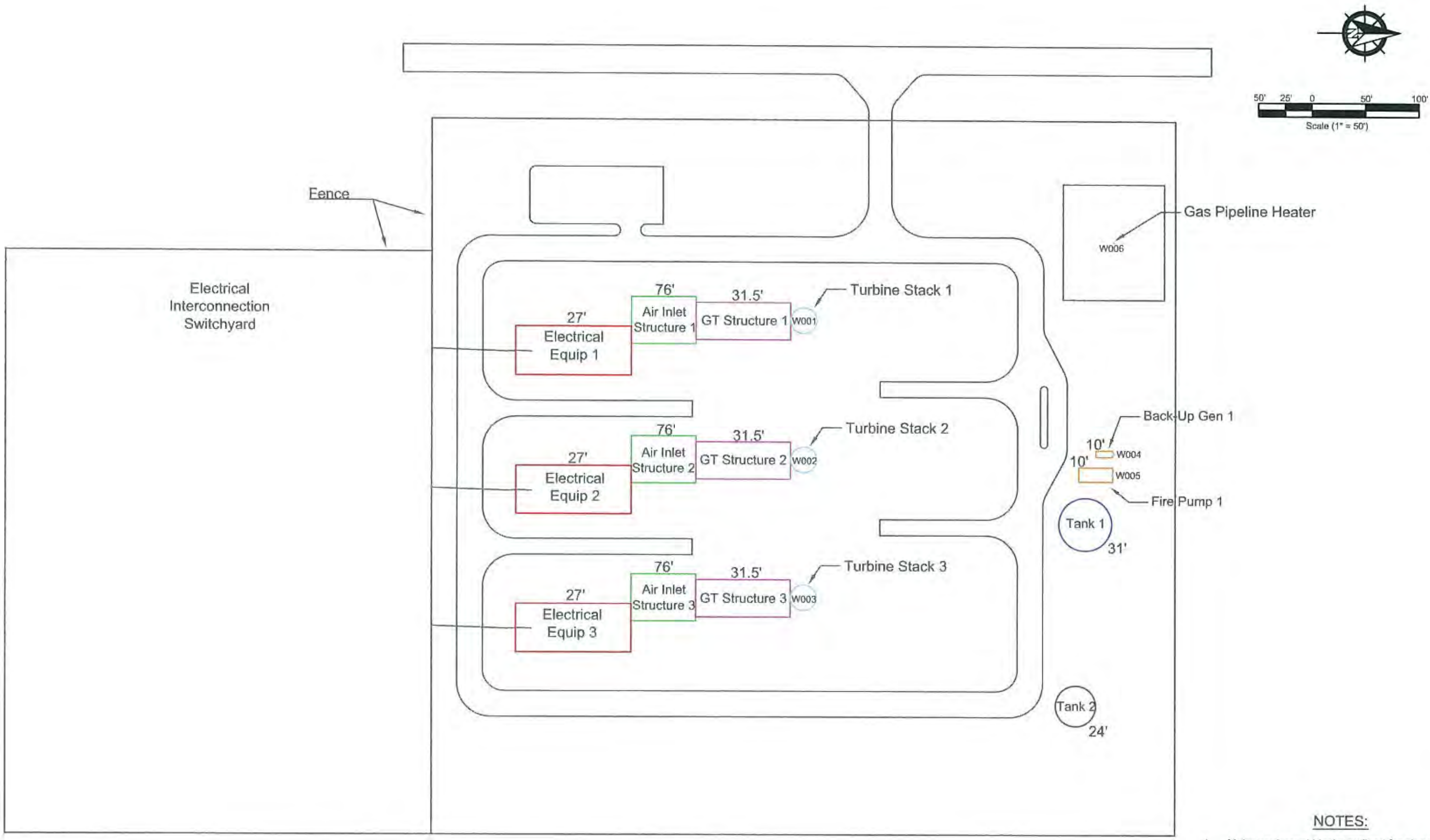
Wharton County, TX

Legend

Power Station Location

Overview Map

Path: P:\GIS\Indeck_Wharton\GIS\Spatial\MXD\Fig1_1_General_Location.m



NOTES:

1. Major equipment blocks outlined for air permit modeling purposes. For detailed layout see IES Drawing Wharton GA-1580-01.
2. This layout reflects a portable water treatment scenario, which eliminates the waste water and blended water tanks and increases the size of the demin water tank to hold 200,000 gallons.
3. Building height elevations in feet above grade.
4. The base elevation for the site is 65 feet above mean sea level.

Emission Point Location: UTM-E (m), UTM-N (m) [in NAD83, zone 14]

GT1	GT2	GT3	Emergency Gen	Fire Pump	Gas Line Heater
771215.5, 3216538.1	771255.1, 3216538.1	771294.7, 3216538.1	771253.1, 3216627.2	771259.1, 3216626.7	771192.7, 3216627.1

No.	Revision/Issue	Date
A		4/2/13

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Figure 2-2
Plot Plan
Indeck Wharton Energy Center
Wharton County, TX

General Arrangement

Project: 3x0 SC (Air Permit Control Points)
Date: 4/2/13
Sheet: GA-1580-04

FILENAME: Wharton - GA-1580-01_04 RevA.dwg

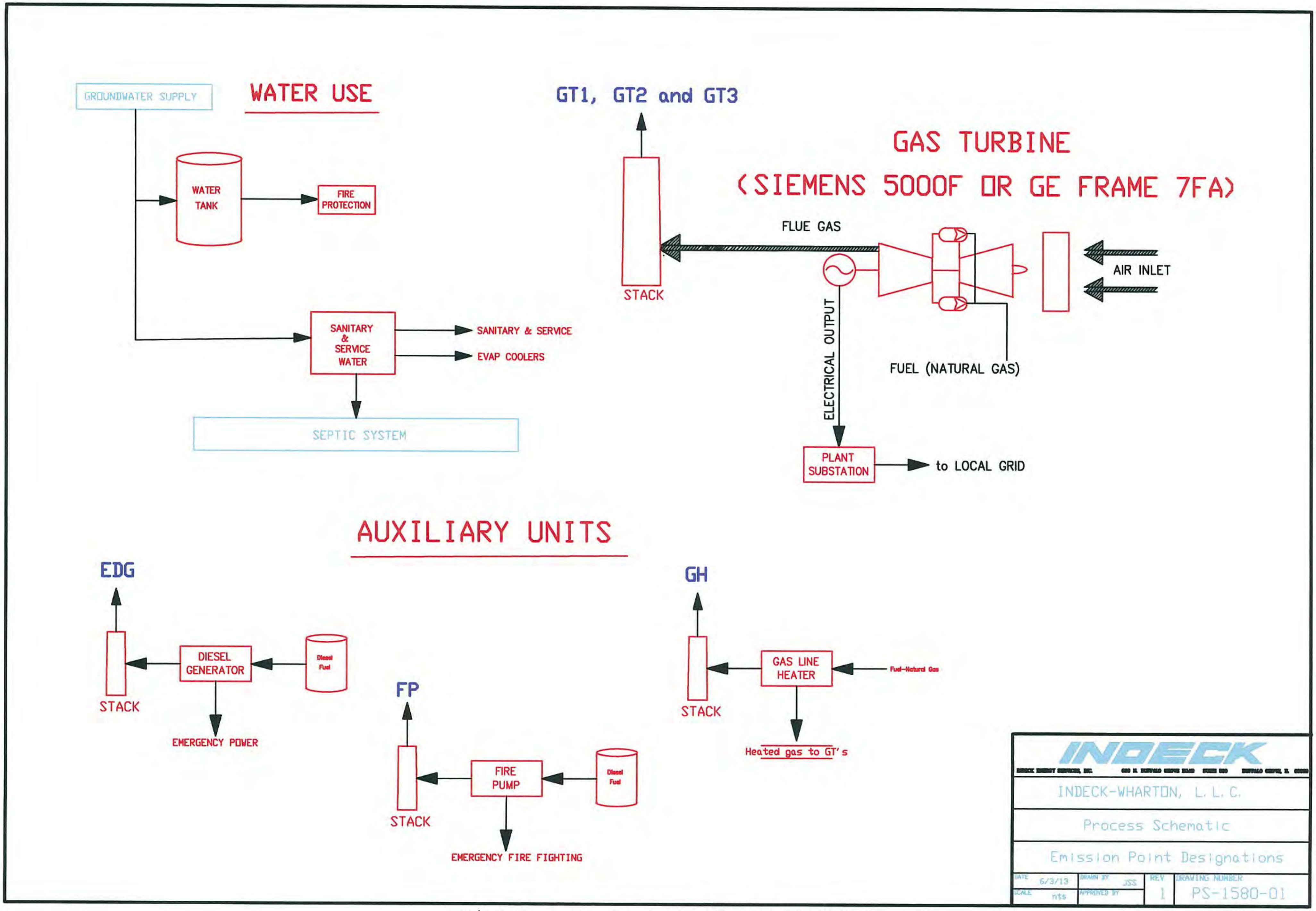


Figure 2-3: Process Flow Diagram

3.0 GHG EMISSIONS

A summary of the GHG emissions for the Project are presented in this section for each emission unit. Emissions calculations are detailed in Appendix B. A summary of the annual potential GHG emissions for the Project is shown below in Table 3-1. To be conservative, the GHG emission rate shown for the CTs in Table 3-1 represents emissions for the higher of the two turbine models currently under consideration.

Table 3-1
Indeck – Wharton Potential GHG Emissions

Source	Annual Potential GHG Emissions (tons)				
	CO_2	CH_4	N_2O	SF_6	CO_2e**
Combustion Turbines (higher of the 2 models)*	1,074,496	19.9	2.0	-	**1,075,530**
EDG	242.6	<0.01	<0.01	-	**243.4**
FP	30.7	<0.01	<0.01	-	**30.8**
Gas Pipeline Heater	624.23	0.01	<0.01	-	**624.8**
Gas Piping	0.02	2.91	-	-	**61.1**
Circuit Breaker Dielectric Insulator	-	-	-	0.02	**365.8**
TOTAL	**1,075,394**	**22.8**	**2.0**	**0.02**	**1,076,856**

* Includes startup/shutdown emissions.
** CO_2e or "carbon dioxide equivalent" is the sum of CO_2, CH_4, N_2O, and SF_6 in equivalent CO_2 using Global Warming Potentials as described below.

GHG emissions are presented in CO_2 equivalent or "CO_2e" since the different GHG constituents have different heat trapping capabilities. Factors used to calculate CO_2e are called Global Warming Potentials (GWP) and were taken from Table A-1 of 40 CFR 98, Subpart A. GWPs are shown in Table 3-2 below.

Table 3-2
GWP of CO_2e Constituents

GHG	GWP
CO_2	1
CH_4	21
N_2O	310
SF_6	23,900

The equation to calculate CO_2e is therefore;

CO_2e = (CO_2 tpy X CO_2 GWP) + (CH_4 tpy X CH_4 GWP) + (N_2O tpy X N_2O GWP) + (SF_6 tpy X SF_6 GWP)

3.1 Combustion Turbines

The facility will consist of three natural gas-fired simple cycle CTs; either the GE Frame 7FA model or the Siemens SGT6 5000F model. The GE and Siemens turbines have slightly different heat input capacities and heat rates. Indeck is proposing to operate the turbines a maximum of 2,500 hours per year plus 300 startups.

Regardless of the turbine model, natural gas combustion will generate CO_2, CH_4, and N_2O emissions. Table 3-3 shows emissions rates, maximum short-term emissions, and annual potential to emit from the turbines. Emissions are further detailed in calculations presented in Appendix B. Annual potential to emit for the turbines is based on natural gas combustion at maximum load for 2,500 hrs/yr per turbine and 300 startups/shutdowns, per year. The proposed emission limits are based on 40 CFR Part 75 (CO_2) and Part 98 (CH_4 and N_2O) default emission factors.

In addition to normal operations, SUSD will generate small amounts of the GHG emissions CO_2, CH_4, and N_2O emissions during each event. To estimate annual GHG emissions, maximum load for all 2,500 hrs/yr were assumed plus 900 startups (300 per turbine). Shutdown emissions are minimal and assumed to be included in the startup calculation.

Table 3-3
GE Combustion Turbines – Proposed GHG Emissions

Pollutant	**Proposed Emission Rate** (lb/mmBtu)	**Basis for Emission Rate**	**Turbine Maximum Hourly Emissions** (lbs/hr **per turbine** based on maximum hourly heat input)	**Annual Potential to Emit** (tpy for **all three turbines** based on a projected annual capacity of 2500 hrs/yr per turbine)[b]
CO_2	118.9	40 CFR 75, Appendix G	263,482	962,109
CH_4	0.0022	40 CFR Part 98, Table C-2	4.88	17.5
N_2O	0.00022	40 CFR Part 98, Table C-2	0.49	1.8
CO_2e	**119.01[a]**	**-**	**263,736**	**963,035**

[a] sum of CO_2, CH_4, and N_2O. CH_4 assumed to have 21 and N_2O assumed to have 310 times the heat trapping capabitliy of CO_2.

[b] Based on maximum heat input at 100% load, 70°F, and includes 300 startups/shutdowns per year for each turbine.

Table 3-4
Siemens Combustion Turbines – Proposed GHG Emissions

Pollutant	**Proposed Emission Rate** (lb/mmBtu)	**Basis for Emission Rate**	**Turbine Maximum Hourly Emissions** (lbs/hr **per turbine** based on maximum hourly heat input)	**Annual Potential to Emit** (tpy for **all three turbines** based on a projected annual capacity of 2500 hrs/yr per turbine) [b]
CO_2	118.9	40 CFR 75, Appendix G	280,247	1,074,496
CH_4	0.0022	40 CFR Part 98, Table C-2	5.19	19.9
N_2O	0.00022	40 CFR Part 98, Table C-2	0.52	2.0
CO_2e	**119.01**[a]	**-**	**280,517**	**1,075,530**

[a] sum of CO_2, CH_4, and N_2O. CH_4 assumed to have 21 and N_2O assumed to have 310 times the heat trapping capabitliy of CO_2.

[b] Based on 100% load, 70°F, and includes 300 startups/shutdowns per year for each turbine.

3.2 Emergency Diesel Generator & Diesel Fire Pump

Combustion of diesel fuel in the EDG and FP generates CO_2, CH_4, and N_2O emissions. Table 3-5 shows maximum short-term emissions and annual potential to emit from the EDG and FP. Annual potential to emit for the EDG and FP are based on diesel fuel combustion and 500 hrs/yr operation for the EDG and 300 hrs/yr for the FP. The proposed emission limits for the EDG and FP are based on AP-42 emission factors. Emissions calculations are also detailed in Appendix B.

Table 3-5
EDG Proposed GHG Emissions

Pollutant	**Proposed Emission Rate** (lb/mmBtu)	**Basis for Emission Rate**	**EDG Maximum Hourly Emissions** (lbs/hr)	**Annual Potential to Emit** (tpy based on 500 hrs/yr)
CO_2	162.3	40 CFR 75, Appendix G	970.2	242.6
CH_4	0.0066	40 CFR Part 98, Table C-2	0.04	<0.01
N_2O	0.0013	40 CFR Part 98, Table C-2	0.01	<0.01
CO_2e	**162.84**	**-**	**973.5**	**243.4**

[a] sum of CO_2 and CH_4. CH_4 assumed to have 21 times the heat trapping capabitliy of CO_2.
NOTE 1 - EDG is rated at 5.98 mmBtu/hr
NOTE 2 – assumes a CH_4 GWP of 21 and GWP of 310 for N_2O.

Table 3-6
FP Proposed GHG Emissions

Pollutant	**Proposed Emission Rate** (lb/mmBtu)	**Basis for Emission Rate**	**FP Maximum Hourly Emissions** (lbs/hr)	**Annual Potential to Emit** (tpy based on 300 hrs/yr)
CO_2	162.3	40 CFR 75, Appendix G	204.50	30.7
CH_4	0.0066	40 CFR Part 98, Table C-2	0.01	0.03
N_2O	0.0013	40 CFR Part 98, Table C-2	0.00	0.1
CO_2e	**162.84**	**-**	**205.18**[a]	**30.8**

[a] sum of CO_2 and CH_4. CH_4 assumed to have 21 times the heat trapping capabitliy of CO_2.
NOTE 1 - FP is rated at 175 hp and consumes 9 gallons of diesel/hr at max load.
NOTE 2 – assumes a CH_4 GWP of 21 and GWP of 310 for N_2O.

3.3 Natural Gas Pipeline Heater

The natural gas pipeline heater will combust small amounts of natural gas in order to heat the pipeline gas prior to the gas going to the combustion turbines. Natural gas combustion will generate CO_2, CH_4, and N_2O emissions. Annual emissions calculations assume 3,500 hours of operation per year to include normal operation of the turbines plus startups. The proposed emission limits for the pipeline heater are based on AP-42 emission factors and are shown below in Table 3-7.

Table 3-7
Pipeline Heater Proposed GHG Emissions

Pollutant	**Proposed Emission Rate** (lb/MMBtu)	**Basis for Emission Rate**	**Gas Pipeline Heater Maximum Hourly Emissions** (lbs/hr)	**Annual Potential to Emit** (tpy based on 3500 hrs/yr)
CO_2	118.9	40 CFR 75, Appendix G	356.70	624.23
CH_4	0.0022	40 CFR Part 98, Table C-2	0.01	0.01
N_2O	0.00022	40 CFR Part 98, Table C-2	0.00	0.00
CO_2e	**119.01**[a]	**-**	**357.04**[a]	**624.83**

[a] sum of CO_2, CH_4, and N_2O. CH_4 assumed to have 21 and N_2O assumed to have 310 times the heat trapping capabitliy of CO_2.
NOTE 1 – Pipeline Heater is rated at 3 mmBtu/hr
NOTE 2 – assumed gas heat content of 1,020 Btu/cf
NOTE 2 – assumes a CH_4 GWP of 21 and GWP of 310 for N_2O.

3.4 Natural Gas Piping

Fugitive natural gas emissions will be emitted from the pipeline valves and flanges. Natural gas is primarily methane which is a GHG. Fugitive natural gas emission factors were obtained from Oil and Gas Production Operations from Addendum to RG-360, Emission Factors for Equipment Leak Fugitive Components, TCEQ, January 2008, Average Emission Factors – Petroleum Industry (Table 4). Fugitive emission factors and emission calculations are shown in Table 3-8 below.

Table 3-8
Fugitive Pipeline CH_4 Emissions

Component	No. of Components	Emission Factor (lb/hr-component)	Gas Pipeline Fugitive Annual CH_4 Emissions (tpy)	Gas Pipeline Fugitive Annual CO_2 Emissions (tpy)	Annual Potential CO_2e Emissions (tpy)
Valves	103	0.00992	1.72	0.01	36.05
Flanges	309	0.00086	0.45	0.002	9.37
Pressure Relief Valves	10	0.0194	0.33	0.002	6.84
Connectors	570	0.00044	0.42	0.002	8.85
TOTAL			2.91	0.02	61.11

NOTE – emissions assume the gas to be 95.97% CH_4 and 0.53% CO_2, and CO_2e estimate assumes a GWP of 21 for the CH_4 emissions. Based on 3,500 hrs/yr (normal ops plus startups).

3.5 Circuit Breaker Dielectric Insulator

The Project will have a maximum, worst case scenario of 14 circuit breakers on site which will contain the GHG sulfur hexafluoride (SF_6). SF_6 is an excellent electrical insulator used for arc quenching and current interruption in high-voltage electrical equipment. During operation of the facility, a very small leak rate of SF_6 is expected. An estimated 0.5% SF_6 leak rate per year is assumed for the circuit breaker equipment. This value is from "SF6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Potential Greenhouse Gas Emissions Source" by J. Blackman, *Program Manager*, *U.S. Environmental Protection Agency*, and M. Averyt and Z. Taylor, from *ICF Consulting*.

Table 3-9
Fugitive Circuit Breaker CO_2e Emissions

Circuit Breaker Description	Amount of SF_6 at Full Charge (lbs)	Number of Breakers	Leak Rate (%)	Annual SF_6 Potential to Emit (tpy)	Annual CO_2e Potential to Emit (tpy)
Generator Circuit Breaker	24.2	3	0.5	0.0002	4.34
HV Power Circuit Breaker	550	11	0.5	0.015	361.49

[a] assumes an SF_6 GWP of 23,900.

3.6 Proposed GHG Monitoring

a. Indeck proposes to determine the hourly CO_2 emission rate and CO_2 mass emissions for the CT using an O_2 monitor according to appendix F to 40 CFR Subpart 75. In accordance to 40 CFR Subpart 75.20(c)(4), Indeck will determine hourly CO_2 concentration and mass emissions with an exhaust flow monitoring system; a continuous O_2 concentration monitor; fuel F and Fc factors; and, where O_2 concentration is measured on a dry basis, either, a continuous moisture monitoring system, as specified in §75.11(b)(2), or a fuel-specific default moisture percentage (if applicable), as defined in §75.11(b)(1); and by using the methods and procedures specified in appendix F to 40 CFR Subpart 75.

b. Indeck proposes to install, calibrate, and operate a fuel flow meter and perform periodic scheduled gross calorific value (GCV) fuel sampling for the CT and will meet the applicable requirements, including certification testing, of 40 CFR Part 75, Appendix D and 40 CFR Part 60 to be used in conjunction with the Fc factor based on the procedures to calculate the CO_2 emission rate in 40 CFR Part 75, Appendix F.

c. O_2 analyzers will continuously monitor and record O_2 in the CT exhaust gas. The analyzer will reduce the O_2 readings to an averaging period of 6 minutes or less and record it at that frequency.

d. The O_2 analyzers will be quality-assured at least quarterly using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, §5.1.2, with the following exception: a relative accuracy test audit is not required once every four quarters (i.e., two successive semiannual CGAs may be conducted).

e. Indeck will implement a periodic schedule for GCV fuel sampling. All certification tests will be completed on or before the earlier of 90 unit operating days or 180 calendar days after the date the unit commences commercial operation (as defined in 40 CFR Part 75, Appendix D and G).

4.0 REGULATORY REVIEW AND APPLICABILITY

The EPA published final rules for permitting major sources of GHGs on June 3, 2010. After July 1, 2011, new sources having the potential to emit greater than 100,000 tpy of GHGs on a carbon dioxide equivalent (CO_2e) basis and modifications resulting in increases of greater than 75,000 tpy of CO_2e are subject to PSD permitting requirements. The Project will be a new source capable of emitting greater than 100,000 tpy of CO_2e. As a result, Indeck is required to obtain a PSD GHG air permit from EPA (due to the December 23, 2010 issuance of a Federal Implementation Plan authorizing EPA to issue PSD GHG air permits in Texas).

EPA signed a proposed 40 CFR 60, Subpart TTTT - New Source Performance Standard (NSPS) for GHG Emissions from Electric Utility Generating Units on March 27, 2012. The proposed rule creates a CO_2 rate-based emission limit (lbs CO_2/MW-hr) for electric utility generating units. Under the rule as proposed, simple cycle turbines are exempt as stated in §60.5520(d).

This application satisfies EPA's permitting requirements for obtaining a PSD GHG air permit. The Project also exceeds PSD permitting thresholds for CO and NO_X. A PSD air permit application addressing potential CO and NOx emissions was submitted to TCEQ on June 17, 2013.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

5.1 Introduction

The BACT process is discussed in detail in the EPA document "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting" (NSR Manual) (US EPA, 1990), which is not a rule but acts as a non-binding guidance document for EPA, state permitting authorities and permit applicants. In addition to the 1990 EPA guidance document, the BACT analysis pertaining to GHG has been conducted in accordance with EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases" (US EPA, 2011). The 2011 guidance document refers to the same top-down methodology described in the 1990 document, and it provides additional clarification and detail with regard to some aspects of a BACT analysis for GHGs.

5.1.1 Definition of BACT

40 CFR 52.21(b)(12) defines "Best Available Control Technology" as:

> "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

5.1.2 Top-Down BACT Process

The BACT process is discussed in detail in the Draft EPA document "New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting" (NSR Manual) (US EPA, 1990) which involves the following five steps:

- Step 1: Identify all potential control technologies applicable to the pollutant and process.
- Step 2: Determine the technical feasibility of each control technology identified under Step 1 as applicable to the proposed facility and eliminate those that are infeasible.
- Step 3: Rank the remaining control technologies based on achievable overall control effectiveness.

- Step 4: Evaluate the most effective control technology based on economic, energy, and environmental factors. If the most effective control technology is not feasible as a result of economic, energy, or environmental factors, the next most effective technology is evaluated. This process continues until a technology is selected. If the top ranked technology is chosen as the BACT, it is not necessary to review the economic, environmental, and energy factors.
- Step 5: Select as BACT the most effective option not eliminated in Steps 2 – 4 above and corresponding emission limit for the pollutant.

The application of each of these five steps for the proposed facility's GHG emissions is discussed in the following sections.

5.2 Combustion Turbines

5.2.1 Step 1: Identify Potentially Feasible GHG Control Options

In Step 1, the applicant must identify all "available" control options which have the potential for practical application to the emission unit and regulated pollutant under evaluation, including lower-emitting process and practices. In assessing available GHG control measures, we reviewed EPA's RACT/ BACT/ LAER Clearinghouse, Southern Research's Greenhouse Gas Mitigation measures[1], the South Coast Air Quality Management District's BACT determinations, and the Calpine Corporation - Deer Park Energy Center (DPEC) GHG permit information found on the EPA Region 6 website[2]. The DPEC Project involves the construction of a new 180 MW natural gas-fired combined cycle combustion turbine at an existing power generation facility in Harris County, Texas. The only document found with pertinent GHG BACT information was the DPEC permit data. The permit defines BACT for a proposed new CT to be energy efficient combustion (demonstrated by a heat rate limit) and low CO_2e emissions (CO_2e emission limits). Specifically, BACT was cited as CO_2, CH_4, and N_2O emission limits for the turbine on a ton per year basis as well as a ton/MWh basis. The ton CO_2/MWh (net) is calculated on a 30-day rolling average basis while the ton CO_2e emissions are calculated on a 365-day rolling average basis.

For the Project, potential GHG controls are:

1. low carbon-emitting fuels;
2. energy efficiency and heat rate;
3. carbon capture and storage (CCS).

5.2.2 Step 2: Technical Feasibility of Potential GHG Control Options

1. Low Carbon-Emitting Fuels

As described in this application, simple cycle CT technology and the use of natural gas as a fuel source is fundamental to the primary purpose of the Project; distillate oil will not be a fuel source for the CTs. Therefore, in accordance with EPA's guidance, the GHG BACT analysis does not need to include an

[1] http://www.southernresearch.org/environment-energy/greenhouse-gas-mitigation
[2] http://yosemite.epa.gov/r6/Apermit.nsf/AirP#A

analysis of alternative fuels, which would redefine the source.[3] In addition, natural gas combustion generates significantly lower carbon dioxide emission rates per unit heat than distillate oil or coal as shown in Table 5-1 below. Biofuels would reduce fossil-based carbon emissions. However, use of biofuels in CTs has issues that have yet to be resolved. These issues involve the high sodium and potassium content which causes spalling of the thermal barrier coating and the tendency of biofuel to turn into a jelly-like substance at low temperatures. Fuel tanks would require heaters as well as nitrogen blankets to keep the fuel from coming in contact with oxygen which causes biofuels to degrade. For these reasons, biofuels are not technically feasible at this time. The use of low carbon-emitting fuel, natural gas, is technically feasible for the Project.

Table 5-1
CO_2e Comparison for Typical Fuels

Fuel	CO_2 (lbs/mmBtu)	CH_4 (lbs/mmBtu)	N_2O (lbs/mmBtu)	CO_2e (lbs/mmBtu)
Natural Gas*	118.9	0.0022	0.00022	119.01
Distillate Oil*	162.3	0.0066	0.0013	162.84
Coal**	242	0.016	0.0032	243.33

ND = non-detect
*CO_2 emission factors from 40 CFR 75, Appendix G. CH_4 & N_2O emission factors from 40 CFR Part 98
**CO_2 emission factor from Table 1.1-20 of AP-42, assuming medium-volatile bit coal, 12,500 Btu/lb. CH_4 and N_2O emission factors from Table 1.1-19 of AP-42 assuming PC-fired dry bottom, tangentially fired boiler.

2. Energy Efficiency and Heat Rate

EPA's GHG permitting guidance states,

> "Evaluation of [energy efficiency options] need not include an assessment of each and every conceivable improvement that could marginally improve the energy efficiency of [a] new facility as a whole (e.g., installing more efficient light bulbs in the facility's cafeteria), since the burden of this level of review would likely outweigh any gain in emissions reductions achieved. EPA instead recommends that the BACT analyses for units at a new facility concentrate on the energy efficiency of equipment that uses the largest amounts of energy, since energy efficient options for such units and equipment (e.g., induced draft fans, electric water pumps) will have a larger impact on reducing the facility's emissions...."[4]

EPA also recommends that permit applicants "propose options that are defined as an overall category or suite of techniques to yield levels of energy utilization that could then be evaluated and judged by the permitting authority and the public against established benchmarks....which represent a high level of performance within an industry". With regard to electric generation from combustion sources, the CT is generally considered to be the most efficient technology. Below is a discussion of energy efficiency and heat rate.

[3] US EPA (2011), pp. 26-28.
[4] US EPA (2011), p. 31.

GHG emissions from electricity production are primarily a function of the amount of fuel burned; therefore, a key factor in minimizing GHG emissions is to maximize the efficiency of electricity production. Another way to refer to maximizing efficiency is minimizing the heat rate. The heat rate of an electric generating unit is the amount of heat needed in British Thermal Units (BTU) to generate a kilowatt of electricity (kWe), usually reported in BTU/kWe-hr. Older, more inefficient boilers and turbines consume more fuel to generate the same amount of electricity as newer, more efficient boilers and turbines. This is due to equipment wear and tear, improved design in newer models as well as the use of higher quality metallurgy. In general, boilers have a higher heat rate than CTs due to the loss of energy in the transfer of heat from combustion to the water tubes. The combustion energy in a turbine is more directly imparted on the turbine blade than a boiler.

It is important to note that the scope of the proposed project is to install approximately 650 MW of electric generation based on three "F" Class turbines. "G" Class turbines are slightly more efficient and thus have a lower heat rate; however, "G" Class turbines are more expensive and generate approximately 400 MW per turbine (or 800 MW for two turbines). Although "G" Class turbines are slightly more energy efficient that the proposed "F" Class turbines, "G" Class turbines would alter the scope of the Project due to their size. Heat rates of the two potential "F" Class turbine models are shown in Table 5-2 below.

Table 5-2
Summary of Indeck Wharton's Turbine Heat Rates

Equipment Option	Heat Rate* (Btu/kW-hr)
GE 7FA	9,890
Siemens 5000F	10,363

* Siemens heat rate based on 100% load at 70°F ambient temperature and HHV. GE heat rate based on 100% load at 70°F ambient temperature and HHV. Both scenarios are the worst case (maximum) hourly CO_2 emission rates.
NOTE – Ancillary Equipment including the Emergency Diesel Generator, Fire Water Pump and Gas Pipeline Heater would be the same for either scenario.

3. Carbon Capture and Storage

With regard to CCS, as identified by US EPA,

> "CCS is composed of three main components: CO_2 capture and/or compression, transport, and storage. CCS may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. For example, the temperature, pressure, pollutant concentration, or volume of the gas stream to be controlled, may differ so significantly from previous applications that it is uncertain the control device will work in the situation currently undergoing review. Furthermore, CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and site-specific considerations (e.g., space for CO_2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options)....While CCS is a

> promising technology, EPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases."[5]

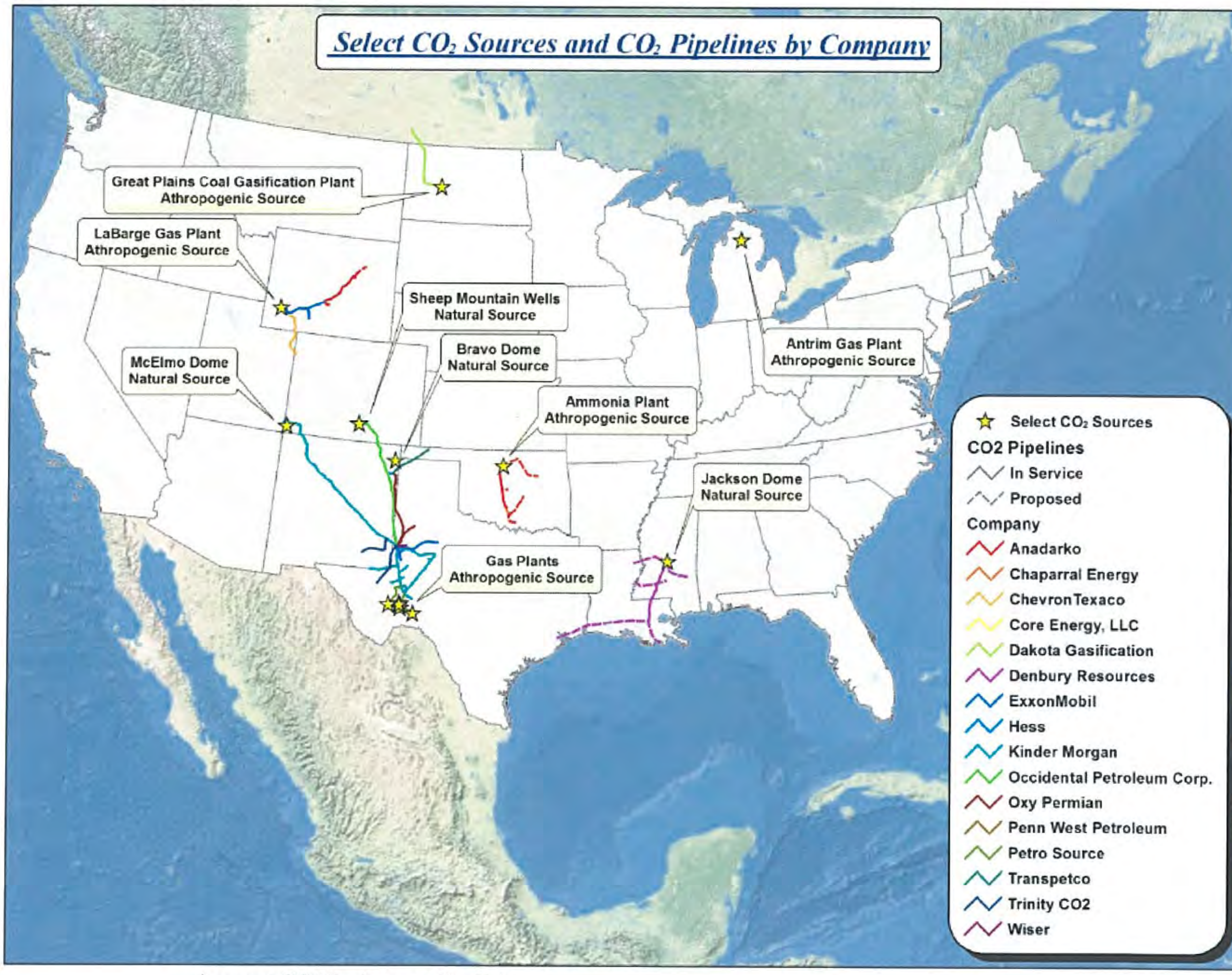
As identified by the August 2010 Report of the Interagency Task Force on Carbon Capture and Storage (co-chaired by US EPA and the US Department of Energy), while amine- or ammonia-based CO_2 capture technologies are commercially available, they have been implemented either in non-combustion applications (i.e., separating CO_2 from field natural gas) or on relatively small-scale combustion applications (e.g., slip streams from power plants, with volumes on the order of what would correspond to one megawatt), and

> "scaling up these existing processes represents a significant technical challenge and potential barrier to widespread commercial deployment in the near term....it is unclear how transferable the experience with natural gas processing is to separation of power plant flue gases, given the significant differences in the chemical make-up of the two gas streams. In addition, integration of these technologies with the power cycle at generating plants present significant cost and operating issues that will need to be addressed to facility widespread, cost-effective deployment of CO_2 capture....Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant applications."[6]

Regarding pipeline transport for CCS, the nearest existing CO_2 pipeline infrastructure is the Denbury Greencore Pipeline in Alvin, Texas (see Figure 5-1); more than 60 miles from the Project. Figure 5-1 shows the Greencore Pipeline to be proposed but the pipeline has been constructed. With regard to storage for CCS, the Interagency Task Force concluded that while there is currently estimated to be a large volume of potential storage sites, "to enable widespread, safe, and effective CCS, CO_2 storage should continue to be field-demonstrated for a variety of geologic reservoir classes" and that "scale-up from a limited number of demonstration projects to widescale commercial deployment may necessitate the consideration of basin-scale factors (e.g., brine displacement, overlap of pressure fronts, spatial variation in depositional environments, etc.)".[7]

[5] US EPA (2011), pp. 35-36.
[6] Interagency Task Force on Carbon Capture and Storage (2010), p. 28 and p. 50.
[7] Interagency Task Force on Carbon Capture and Storage (2010), p. 51.

Figure 5-1 Existing and Planned CO_2 Pipelines in the United States, with Selected Sources. (From: "Report of the Interagency Task Force on Carbon Capture and Storage,"



August 2010, Appendix B.)

Based on the abovementioned EPA guidance regarding technical feasibility and the conclusions of the Interagency Task Force for the CO_2 capture component alone (let alone a detailed evaluation of the technical feasibility of right-of-ways to build a pipeline or of storage sites), CCS is not technically feasible. However, given the possibility of alternate opinions that CCS is technically feasible and to ensure a complete application, Indeck has conservatively chosen to carry the CCS option forward in the BACT analysis as if it were technically feasible.

5.2.3 Step 3: Ranking of Technically Feasible GHG Control Options by Effectiveness

The ranking of the three options discussed in Section 5.2.2 by effectiveness (most effective to least effective) is as follows:

1. CCS (70% CO_2 removal and probably more)[8]

2. Low carbon-emitting fuels (GHG emissions from gas are 50% below solid fuels and 30% below liquid fuels on a lb/mmBtu basis)

3. Energy efficiency / Low Heat Rate (10-20% less GHG than older, oil-fired simple cycle turbines)

5.2.4 Step 4: Evaluation of Most Effective GHG Control Options

5.2.4.1 Energy, Environmental, and Economic Impacts

The Project has accounted for Items #2 and 3 from Section 5.2.3 above by employing state-of-the-art, highly efficient, natural gas-fired CT technology. In this section, we will explore Item #1.

CCS

Although CCS would reduce CO_2 emissions by possibly more than 70%, there are energy and environmental impacts associated with this technology. According to a June 2010 report by the General Accounting Office, parasitic load due to the capture and storage of CO_2 emissions is between 21-32%. If the electricity needed to power the CCS system were to be generated by Indeck, the Project's heat rate (efficiency) would be adversely impacted (greatly reduced) with a potential 21-32% fuel input increase in order to achieve an equivalent electric output. The pipeline needed to transport CO_2 to a storage facility would need to be constructed to traverse more than 60 miles. In doing so, it is possible that ecologically sensitive areas would be impacted due to the distances involved. For this reason, CCS has adverse energy and environmental impacts.

The Interagency Task Force on CCS identified a capture cost of $60 per metric tonne for integrated gasification combined-cycle (IGCC) coal-fired power plants, $95/tonne for pulverized coal (PC) power plants, and $114/tonne for natural gas-fired combined cycle (NGCC) power plants.[9] In order to transport the CO_2, a pipeline of more than 60 miles must be constructed. The actual length of pipeline needed to cover a linear distance of 60 miles may be significantly longer. For example, for two real examples in North Carolina, a 2007 Duke University study calculated that the least-cost pipeline path distances were approximately 1.6-1.8 times the linear distances, as shown in Table 10[10]. Therefore, it is likely that the pipeline path distance needed to cover a linear distance of 60 miles is closer to 100 miles.

[8] Rochelle (2009) has identified that "Seventy to 95% removal probably represents the range where the cost of CO_2 removal ($/ton) is minimized. However, there are few fundamental barriers to greater removal."
[9] Interagency Task Force on Carbon Capture and Storage (2010), p. 50.
[10] A study referenced by the Interagency Commission (Williams et al., 2007) was based on costs of $44,000-$46,000 per inch-mile.

Table 5-3
Pipeline Distances

	Identified by Williams et al. (p. 19)	
	Route 1	**Route 2**
Linear Distance (approx.)	167 miles	74 miles
Least-Cost Pipeline Path Distance	275 miles	133 miles

Capital costs for natural gas pipelines, in units of dollars per inch-mile (i.e., cost per inch of diameter per mile of length), can vary significantly. The Duke study calculated capital costs based on $44,000-46,000 per inch-mile (from a 2006 reference)—plus multipliers for various crossings—but a subsequent Interstate Natural Gas Association of America (INGAA) study showed that there was a significant cost spike in 2006-2007 (reaching nearly $100 per inch-mile), and estimated that costs in 2011 and later would probably be closer to $60,000 per inch-mile (ICF, 2009b), or $72 million for a 12-inch, 100 mile pipeline.

In addition, the capital cost of constructing a pipeline does not include the cost of operating and maintaining a pipeline. A separate INGAA study (ICF, 2009a), which addressed CO_2 pipelines specifically, noted that (a) there are differences between CO_2 pipeline and natural gas pipeline (in terms of pipeline design as well as operations—i.e., pumping of a supercritical fluid rather than compression at booster stations) and (b) that identifying a total cost per ton of CO_2 is highly dependent on pipeline length and diameter, which is in turn dependent on the extent to which other CO_2 sources can be tied into the same pipeline. An example calculation conducted for an idealized case where eight 500 MW power plants use 150 miles of pipeline (including 100 miles of 30-inch diameter mainline shared by all eight, 25 miles of 16-inch pipeline for each pair, and 25 miles of 12-inch pipeline for each individual power plant) showed a "Total Cost of Service" of $4.61 per metric tonne of CO_2 ($4.18 per ton CO_2), assuming each plant emits approximately 3.4 million tonnes (3.8 million tons) of CO_2 per year. For a case of one power plant only (i.e., 12-inch pipeline), INGAA identified a cost of $4.36 per metric tonne per 75 miles, which would translate to approximately $5.81/tonne ($6.48/ton) for 100 miles (if it is even technically feasible to run pipe this small for this distance). Assuming a very conservative control efficiency of 95%, the maximum CO_2 that could be captured is approximately 25% of the single power station case described above (i.e., approximately 997,500 tons/year), and therefore the $/ton associated with 12-inch pipeline would be approximately 4 times as much ($25.92/ton).

Storage is a separate cost, although generally not believed to be significant compared to the costs of capture (including initial compression) and transportation (pipeline). Not considering storage costs, the cost to capture and transport CO_2 from the Project would total approximately $153/ton, which is $114/ton for 997,500 tons CO_2 captured = $114 million plus $25.92/ton for the pipeline construction = $26 million. CCS is clearly economically infeasible, as anticipated by EPA in their March 2011 GHG permitting guidance (US EPA, 2011a) with capture and pipeline costs of nearly $140 million.

Separately, there are energy and environmental impacts associated with having to separate, compress, and pump the CO_2 over a distance of 100 miles. We have not quantified these here in part because of the complexity in doing so (i.e., impacts are dependent on what route the pipeline would take, if it is even technically feasible to install the pipeline) but mostly because CCS is clearly economically infeasible for the Project simply based upon capture and transport costs noted above.

5.2.5 Step 5: Select GHG BACT

It is our opinion that the very low heat rates associated with the CT technology selected for the Project and the use of natural gas, without further CCS control, justifies BACT for the Project. In order to ensure that the turbines will operate in an energy efficient manner, Indeck is proposing two types of GHG emission limits. First, Indeck proposes mass emission limits in tons per year (tpy) of GHGs on a 365-day rolling average basis. Second, Indeck proposes an output-based emission limit in tons of CO_2 per megawatt hour (tons CO_2/MWh) for the turbines. [Limit is based on CO_2 emissions only, given that CO_2 emissions from the turbine exhaust comprise more than 99% of the total GHG emissions from the turbine.] Due to load swings, startups, shutdowns, and weather conditions; Indeck proposes that compliance with the turbine mass emission limit be on a 30-day rolling average basis.

In addition to load swings, startups, shutdowns and weather conditions, compliance with the output-based turbine emission limit is affected by system degradation over time. EPA Region I states in the Pioneer Valley Energy Center (PVEC) Permit Number 052-042-MA14 Fact Sheet[11],

> "EPA expects a decrease in efficiency of 2.5% over time can be expected even for a well-operated turbine.[12] In its March 9, 2011 application supplement, PVEC claimed a performance margin of 6%. EPA understands the performance margin addresses factors affecting the efficiency which cannot be controlled by PVEC such as ambient temperature. The actual effect of temperature on a combined cycle turbine will vary depending on the turbine's design. The variation can be as much as 10%.[13]. Based on the information PVEC provided and on EPA's own research regarding unavoidable decreases in efficiency and variability of performance under a reasonable range of conditions, EPA has determined that BACT is met by an emissions limit that is 8.5% higher than the corrected value which must be met during the initial test."

Consequently, the proposed output-based turbine CO_2 emission limit is 8.5% higher than vendor's ISO-corrected, initial CO_2 emission estimates. The GE and Siemens proposed turbine emission limits are shown in Tables 5-4a and 5-4b respectively.

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[11] www.epa.gov/region1/communities/pdf/PioneerValley/FactSheet.pdf

[12] "Combined-cycle gas & steam turbine power plants" by Rolf Kehlhofer, Bert Rukes, Frank Hannemann, Franz Stirnimann, page 242.

[13] "Thermodynamic performance analysis of gas-turbine power-plant" by M. M. Rahman, Thamir K. Ibrahim, and Ahmed N. Abdalla - http://www.academicjournals.org/IJPS/PDF/pdf2011/18Jul/Rahman%20et%20al.pdf

Table 5-4a
Proposed CT GHG Emission Limits – GE Turbines

	GHG Mass Basis		BACT			
Emission Unit		**GHG Potential Emissions (TPY)[2,3]**		**Output-based BACT CO_2 Limit[1,4]**	**Tons per year CO_2e[2,3]**	**Annual BACT Limit (TPY CO_2e[2,3])**
CT1, CT2, CT3 (combined TOTAL)	CO_2	962,109	CO_2	0.64 tons/MWh	962,109	963,035
	CH_4	18	CH_4		374	
	N_2O	2	N_2O		552	

[1] Compliance with the output-based emission limits is based on a 30-day rolling average.
[2] Compliance with the annual emission limits (tpy) is based on a 365-day rolling average.
[3] Includes facility emissions during normal operations as well as startups & shutdowns.
[4] Based on a gross output of 228,541 kW-hr at the 100% load, 70°F ambient case. Initial performance stack testing will be corrected to ISO 3977-2 standard conditions at 59°F, 14.7 psia, and 60 % humidity. On-going limit includes an 8.5% increase over the initial corrected values to account for system degradation – See Section 5.2.5.

Table 5-4b
Proposed CT GHG Emission Limits – Siemens Turbines

	GHG Mass Basis		BACT			
Emission Unit		**GHG Potential Emissions (TPY)[2,3]**		**Output-based BACT CO_2 Limit[1,4]**	**Tons per year CO_2e[2,3]**	**Annual BACT Limit (TPY CO_2e[2,3])**
CT1, CT2, CT3 (combined TOTAL)	CO_2	1,074,496	CO_2	0.67 tons/MWh	1,074,496	1,075,530
	CH_4	20	CH_4		418	
	N_2O	2	N_2O		616	

[1] Compliance with the output-based emission limits is based on a 30-day rolling average.
[2] Compliance with the annual emission limits (tpy) is based on a 365-day rolling average.
[3] Includes facility emissions during normal operations as well as startups & shutdowns.
[4] Based on a gross output of 232,012 kW-hr at the 100% load, 70°F ambient case. Initial performance stack testing will be corrected to ISO 3977-2 standard conditions at 59°F, 14.7 psia, and 60 % humidity. On-going limit includes an 8.5% increase over the initial corrected values to account for system degradation – See Section 5.2.5.

5.2.6 Alternative Technologies

There are numerous turbine options, frame machines, aero-derivatives, and various turbine models. As described earlier, other options include the advanced "G" class (GE Frame 7G) or earlier versions such as the GE Frame 7EA. The G machine provides advanced efficiency and low emissions. However, it does require steam, which is not available for the Project because it is a peaker and not a combined cycle with steam generator. As such, it was ruled out for this application. The Frame 7EA is a widely used turbine, and is the predecessor of the "F" class machine. The Frame 7EA offers reliability and wide acceptability for both peaking and base load power projects. In this application, it would offer a higher heat rate (less efficient) with no improvement in emissions. Also, the 7EA class machine is rated at about 100 MW, thus requiring more than six turbines to achieve the output of three "F" units. With no advantage either operationally or environmentally, the EA machine has been ruled out. Aero-derivatives are another class of gas turbines. They are applicable for simple cycle applications, as they offer low heat rates, acceptable emissions and good operating characteristics. For instance, the GE LM6000 is a 45 MW machine that achieves a heat rate of 8,300 Btu/kWhr. Historically, these aero-derivatives can achieve emission rates of approximately 25 ppm NOx and 10 ppm CO. While they offer attractive heat rates, emissions are problematic and unit size limits overall plant output. An "F" class turbine produces the power output of more than four aero-derivatives such as the LM6000. The lack of gross output per unit and unfavorable emission characteristics eliminates the aero-derivative turbine from selection for the proposed project.

Combined Cycle Combustion Turbines / Steam Plants

CCCT and traditional steam plants are widely used in power generation. These technologies are the primary drivers of the electric grid in both ERCOT and nation-wide. This technology is primarily associated with baseload generation, particularly with the larger units. They offer advantageous heat rates, with CCCT plants now achieving low7,000's btu/kWhr (HHV) heat rates. Traditional coal and oil/gas fired steam plants are in the low 9,000's for heat rates. Emissions can vary widely, but new generation CCCT can achieve NOx rates of 2 ppm. Traditional steam plants can now be designed to meet stringent emission standards, with NOx now meeting 0.05 lbs/mmbtu limits (approximately 13 ppm NOx). While these types of facilities form the backbone of the nation's grid, they are by nature baseload units, not capable of peaking duty. As such, they are not an alternative for Indeck Wharton. The Project is conceived as a peaking power provider. It is designed to be on line within 30 minutes notice, to respond to varying needs of the electric grid, and to expeditiously shutdown when no longer needed. Neither CCCT nor traditional steam plants can meet these requirements. Their startup cycles can reach two to three hours versus the 30 minutes or less for peaking units. The much higher capital costs for CCCT and/or traditional steam plants require greater utilization, which equates to baseload operations of roughly 8,000 annual hours versus peaking units that typically operate at 10% to 30% of the baseload level. As such, annual emissions are much higher due to the greater operating hours. Conceived as a peaking power provider, CCCT and/or traditional steam plants are simply not a viable alternative for the Project.

Internal Combustion Engines

Internal combustion (IC) engines are also employed in peaking power applications. The larger installations are typically multiple units. A single typical generator set could employ a Cat 3600 series engine capable of producing 4 to 5 MW. IC engines typically have very good heat rates in the 7,500 Btu/kWh (HHV) range. Emission rates, however, are usually higher than gas turbines, though back-end controls can limit NOx and CO emissions. These installations are very good in load following as IC engines are quick response units. Regarding applicability to the Project, the overriding concern would be the size limitation. While IC installations are common, they are typically employed in relatively limited numbers in close proximity to load, adjacent to a substation. An installation of this type might employ 10 units and be capable of rapid response to grid conditions with up to 50 MW capacity. This is not the concept of the Project, which proposes a nominal capability of up to 650 MW. While it might be technically possible to achieve such output with IC engines, it is not a realistic configuration. IC engines are thus not considered a feasible alternative for the Project.

Renewables

Wind and solar power projects have been gaining acceptance in recent years. Renewables have an environmental attractiveness in that they are "emissions-free" for the actual power generation cycle. However, they are certainly not free from environmental impact, as wind farms and solar arrays consume vastly more land resources to generate an equivalent amount of power. For instance, a solar field would require approximately 6,500 acres to produce the same energy as the 35 acre footprint of the Project. Renewables, whether wind or solar, are interruptible sources and not suited for peaking purposes. The primary characteristic of peaking power is its ability to respond immediately to grid requirements and to be available at all hours. Neither wind nor solar options are capable of meeting this basic requirement. As such, they are not a suitable alternative to the selected technology for the Project.

It is thus presented that the "F" class combustion turbine is the most suitable technology for the Project. They are ideally suited from an electrical output standpoint, and provide good economic and environmental attributes. Indeck has proposed the best economic and environmental project alternative by employing "F" class turbine technology and limiting the fuel source to natural gas only.

5.3 Emergency Diesel Generator and Fire Pump

The EDG and FP will be fueled by ULSD and operated only during maintenance, testing and emergencies. There are no post combustion GHG controls available for internal combustion engines. GHG BACT for these engines is maintaining the engines to operate efficiently and minimizing their hours of operation. Indeck proposes to limit the EDG to 500 hrs/yr and the FP to 300 hrs/yr.

5.4 Gas Pipeline Heater

The Gas Pipeline Heater will be fueled by natural gas. There are no available, technically feasible add-on GHG controls for this type of combustion unit. GHG control for the Pipeline Heater will be the use of a low GHG-emitting fuel (natural gas) and operated in such a way that optimizes combustion efficiency. Indeck proposes to limit the Gas Pipeline Heater to 3,500 hrs/yr.

5.5 On-Site Natural Gas Piping

Methane emissions occur as fugitives from the on-site gas pipelines and associated equipment. These fugitive emissions are negligible when compared to the facility's GHG emissions, however, are included in the BACT analysis for the purposes of completeness. The only available control method for fugitive pipeline emissions is leak detection. Indeck proposes to implement an as-observed auditory, visual and olfactory (AVO) method for detecting leakage from natural gas piping and the associated equipment.

5.6 BACT Analysis for the Switchyard

Sulfur hexafluoride (SF_6) is currently used as a dielectric medium to rapidly quench electric discharges in transformers, high-voltage circuit breakers, and switchgear at the site. SF_6 is used in place of polychlorinated biphenyls (PCBs) that were banned by Congress in 1979. SF_6 is a man-made gas that is colorless, odorless, non-flammable, chemically stable, and non-poisonous. However, it is a very potent GHG which is approximately 23,900 times more effective at trapping heat than CO_2. There are currently no other feasible alternatives for the use of SF_6 as a dielectric medium. As such, BACT is the use of state-of-the-art circuit breakers designed to meet the American National Standards Institute (ANSI) C37.13 standard for high voltage circuit breakers.

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APPENDIX A
Application Forms

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

Important Note: The agency requires that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued and no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: **Indeck Wharton, LLC**		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: **Mike Ferguson**		
Title: **Vice President - Operations**		
Mailing Address: **600 N. Buffalo Grove Road, Suite 300**		
City: **Buffalo Grove**	State: **IL**	ZIP Code: **60089**
Telephone No.: **847-520-3212**	Fax No.: **847-520-9883**	E-mail Address:
C. Technical Contact Name: **James S. Schneider**		
Title: **Senior Environmental Engineer**		
Company Name: **Indeck Wharton, LLC**		
Mailing Address: **600 N. Buffalo Grove Road, Suite 300**		
City: **Buffalo Grove**	State: **IL**	ZIP Code: **60089**
Telephone No.: **847-520-3212**	Fax No.: **847-520-9883**	E-mail: **jschneider@indeckenergy.com**
D. Site Name: **Indeck Wharton Energy Center**		
E. Area Name/Type of Facility: **Peaking Power Project**		**X** Permanent ☐ Portable
F. Principal Company Product or Business: **Electric Power**		
Principal Standard Industrial Classification Code (SIC): **4911**		
Principal North American Industry Classification System (NAICS): **221112**		
G. Projected Start of Construction Date: **6/1/14**		
Projected Start of Operation Date: **6/1/15**		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.): **west off Route 71, ½ mile south of Danevang**		
Street Address:		
City/Town: **Danevang**	County: **Wharton**	ZIP Code:
Latitude (nearest second): 29° 03' 08"	Longitude (nearest second): 96° 12' 54"	

Texas Commission on Environmental Quality
Form PI-1 General Application for
Air Preconstruction Permit and Amendment

I.	**Applicant Information (continued)**	
I.	Account Identification Number (leave blank if new site or facility):	
J.	Core Data Form.	
	Is the Core Data Form (Form 10400) attached? If No, provide customer reference number and regulated entity number (complete K and L).	X YES ☐ NO
K.	Customer Reference Number (CN):	
L.	Regulated Entity Number (RN):	
II.	**General Information**	
A.	Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES X NO
B.	Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES X NO
C.	Number of New Jobs: **10**	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
	State Senator: **Glenn Hegar**	District No.: **18**
	State Representative: **Phil Stephenson**	District No.: **85**
III.	**Type of Permit Action Requested**	
A.	Mark the appropriate box indicating what type of action is requested.	
	X Initial ☐ Amendment ☐ Revision (30 TAC 116.116(e) ☐ Change of Location ☐ Relocation	
B.	Permit Number (if existing):	
C.	Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*	
	X Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit	
	X Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source	
	☐ Other:	
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES X NO

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

III.	Type of Permit Action Requested *(continued)*	
E.	Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.0	☐ YES **X** NO
1.	Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):	
Street Address:		
City:	County:	ZIP Code:
2.	Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):	
Street Address: **½ mile south of Danevang, west of Route 71**		
City: **Danevang**	County: **Wharton**	ZIP Code:
3.	Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If "NO", attach detailed information.	X YES ☐ NO
4.	Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?	☐ YES X NO
F.	Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.	
List:		
G.	Are you permitting planned maintenance, startup, and shutdown emissions? If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.	☐ YES ☐ NO
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) Is this facility located at a site required to obtain a federal operating permit? If Yes, list all associated permit number(s), attach pages as needed).	☐ YES **X** NO ☐ To be determined
Associated Permit No (s.):		
1.	Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved.	
☐ FOP Significant Revision	☐ FOP Minor	☐ Application for an FOP Revision
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP
X To be Determined		☐ None

III.	**Type of Permit Action Requested *(continued)***	
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2.	Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***	
☐ GOP Issued	☐ GOP application/revision application submitted or under APD review	
☐ SOP Issued	X SOP application/revision application submitted or under APD review	
IV.	**Public Notice Applicability**	
A.	Is this a new permit application or a change of location application?	X YES ☐ NO
B.	Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES X NO
C.	Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES X NO
D.	Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES X NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List:		
E.	Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	
1.	Is there any change in character of emissions in this application?	☐ YES X NO
2.	Is there a new air contaminant in this application?	X YES ☐ NO
3.	Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES X NO
F.	List the total annual emission increases associated with the application	

Turbine Model Case:	GE Frame 7F	Siemens 5000F
CO_2:	963,007 tpy	1,075,394 tpy
CH_4:	20.7 tpy	22.8 tpy
N_2O:	1.8 tpy	2.0 tpy
SF_6:	0.02 tpy	0.02 tpy
CO_2e:	965,091 tpy	1,076,856 tpy

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

TCEQ

V. Public Notice Information *(complete if applicable)*			
A. Public Notice Contact Name: **to be determined**			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
B. Name of the Public Place: **to be determined**			
Physical Address *(No P.O. Boxes)*:			
City:	County:	ZIP Code:	
The public place has granted authorization to place the application for public viewing and copying.			☐ YES ☐ NO
The public place has internet access available for the public.			☐ YES ☐ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits			
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.			
The Honorable: **Philip Spenrath**			
Mailing Address: **309 E. Milan Street, Suite 600**			
City: **Wharton**	State: **Texas**	ZIP Code: **77488**	
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***			☐ YES **X** NO
Presiding Officers Name(s):			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.			
Chief Executive:			
Mailing Address:			
City:	State:	ZIP Code:	
Name of the Indian Governing Body:			
Mailing Address:			
City:	State:	ZIP Code:	

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

V. Public Notice Information ***(complete if applicable) (continued)***	
C. Concrete Batch Plants, PSD, and Nonattainment Permits	
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*	
Name of the Federal Land Manager(s): **to be determined**	
D. Bilingual Notice	
Is a bilingual program required by the Texas Education Code in the School District?	☐ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?	☐ YES ☐ NO
If Yes, list which languages are required by the bilingual program?	
VI. Small Business Classification ***(Required)***	
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☐ YES **X** NO
B. Is the site a major stationary source for federal air quality permitting?	**X** YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	**X** YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES **X** NO
VII. Technical Information	
A. The following information must be submitted with your Form PI-1	
1. **X** Current Area Map	
2. **X** Plot Plan	
3. ☐ Existing Authorizations	
4. **X** Process Flow Diagram	
5. **X** Process Description	
6. **X** Maximum Emissions Data and Calculations	
7. **X** Air Permit Application Tables	
a. **X** Table 1(a) (Form 10153) entitled, Emission Point Summary	
b. ☐ Table 2 (Form 10155) entitled, Material Balance	
c. ☐ Other equipment, process or control device tables	
B. Are any schools located within 3,000 feet of this facility?	**X** YES ☐ NO

VII.	**Technical Information**			
C.	Maximum Operating Schedule:			
Hour(s): 24	Day(s): 7	Week(s): 52	Year(s): 2500 annual hrs	
Seasonal Operation? If Yes, please describe in the space provide below.				☐ YES **X** NO
D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☐ YES **X** NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.				
E.	Does this application involve any air contaminants for which a disaster review is required?			☐ YES **X** NO
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?			☐ YES **X** NO
VIII.	**State Regulatory Requirements** **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*			
A.	Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			**X** YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?			**X** YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?			**X** YES ☐ NO
D.	Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?			**X** YES ☐ NO
IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*			
A.	Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?			**X** YES ☐ NO

B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?	X YES ☐ NO

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

TCEQ

IX.	**Federal Regulatory Requirements** **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment.** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☐ YES X NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES X NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	X YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	X YES ☐ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES X NO

X. Professional Engineer (P.E.) Seal	
Is the estimated capital cost of the project greater than $2 million dollars?	X YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.	
XI. Permit Fee Information	
Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: $ **75000.00**
Paid online?	☐ YES X NO
Company name on check:	
Is a copy of the check or money order attached to the original submittal of this application?	X YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	X YES ☐ NO ☐ N/A

XII. Delinquent Fees and Penalties
This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.
XIII. 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. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: **James S. Schneider, P.E.**
Signature:____________________ *Original Signature Required*
Date: **June 12, 2013**

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: June, 2013	Permit No.:	Regulated Entity No.:
Area Name: Indeck Wharton Energy Center		Customer Reference No.:

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY
GT1, GT2 and GT3	01,02 and 03	Turbines 1,2 and 3	carbon dioxide	791,208	963,109
			methane	14.6	17.8
			nitrous oxide	1.5	1.8
			Based on GE Frame 7FA		includes SUSD

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ - 10153 (Revised 04/08) Table 1(a)
This form is for use by sources subject to air quality permit requirements and may be revised periodically. (APDG 5178 v5)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: June, 2013	Permit No.:	Regulated Entity No.:
Area Name: Indeck Wharton Energy Center		Customer Reference No.:

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY
GT1, GT2 and GT3	01,02 and 03	Turbines 1,2 and 3	carbon dioxide	840,742	1,074,496
			methane	15.6	19.9
			nitrous oxide	1.6	2.0
			Based on Siemens 5000F		Includes SUSD

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: June, 2013	Permit No.:	Regulated Entity No.:
Area Name: Indeck Wharton Energy Center		Customer Reference No.:

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY
EDG	05	DIESEL	carbon dioxide	970.2	242.6
			methane	0.04	0.01
			nitrous oxide	0.01	0.002

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: June, 2013	Permit No.:	Regulated Entity No.:
Area Name: Indeck Wharton Energy Center		Customer Reference No.:

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY
FP	05	Firepump	carbon dioxide	188.04	2.44
			methane	0.008	0.0001
			nitrous oxide	0.0015	0.00002

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ - 10153 (Revised 04/08) Table 1(a)
This form is for use by sources subject to air quality permit requirements and may be revised periodically. (APDG 5178 v5)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: June, 2013	Permit No.:	Regulated Entity No.:
Area Name: Indeck Wharton Energy Center		Customer Reference No.:

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) Name		(A) Pound Per Hour	(B) TPY
GH	06	Heater	carbon dioxide	356.70	445.88
			methane	0.01	0.01
			nitrous oxide	0.0007	0.0008

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ - 10153 (Revised 04/08) Table 1(a)
This form is for use by sources subject to air quality permit requirements and may be revised periodically. (APDG 5178 v5)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: June, 2013	Permit No.:	Regulated Entity No.:
Area Name: Indeck Wharton Energy Center		Customer Reference No.:

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS							
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building Height (Ft.)	6. Height Above Ground (Ft.)	7. Stack Exit Data			8. Fugitives		
(A) EPN	(B) FIN	(C) NAME	Zone	East (Meters)	North (Meters)			(A) Diameter (Ft.)	(B) Velocity (FPS)	(C) Temperature (°F)	(A) Length (Ft.)	(B) Width (Ft.)	(C) Axis Degrees
GT1	01	TURBINE1	14	1215.5	538.1	70	140	30	66	1015			
GT2	02	TURBINE2	14	1255.1	538.1	70	140	30	66	1015			
GT3	03	TURBINE3	14	1294.7	538.1	70	140	30	66	1015			
EDG	04	DIESEL	14	1253.1	627.2	10	20	1.0	98	950			
FP	05	FIREPUMP	14	1259.1	626.7	10	20	0.5	85	950			
GH	06	HEATER	14	1192.7	627.1	na	20	0.5	85	350			

EPN = Emission Point Number
FIN = Facility Identification Number

Reset Form Print Form

TCEQ - 10153 (Revised 04/08) Table 1(a)
This form is for use by sources subject to air quality permit requirements and may be revised periodically. (APDG 5178 v5)

APPENDIX B
Emission Calculations

Indeck Wharton
GE Turbine
GHG Emission Calcs

Emissions During Normal Operations

Assumptions **(For Each Turbine)**:

Max Turbine Heat Rating (HHV)[a]	2,216	MMBtu/hr	
Heat Rating for use in Annual Calcs[b]	2,126	MMBtu/hr	
Gross Output [b]	214,959	kW-hr	
Heat Rate	9,890	BTU/kW-hr	
Annual Capacity	2,500	hrs/yr	
Maximum Annual Heat Input	5,619,500	MMBtu/yr	(including SUSD)
Assumed HHV for Natural Gas	1,025	Btu/cf	
Proposed Output Based Emission Limit[c]	0.64	tons CO_2/MWh	

	Emission Factor	Per Turbine		All 3 Turbines		in CO_2e
	(lb/MMBtu)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	**(tpy)**
CO_2	118.9 - d	263,482	315,977	790,447	947,930	**947,930**
CH_4	0.0022 - e	4.88	5.85	14.63	17.54	**368**
N_2O	0.00022 - e	0.49	0.58	1.46	1.75	**544**
CO_2e	119.01 - f	263,736	316,280.77	791,208	948,842	**948,842**

a - from GE performance spreadsheet - 100% load, 10°F, HHV
b - from GE performance spreadsheet - 100% load, 70°F, HHV
c - includes an 8.5% increase over initial ISO-corrected rate as described in Section 5.2.5 of Application
d - Equation G-4 in Appendix G of 40 CFR Part 75
e - from Table C-2 of 40 CFR Part 98
f - Sum of CO_2, CH_4 and N_2O. CH_4 assumed to have 21 and N2O assumed to have 310 times the heat trapping capability of CO_2

Startup Emissions

Since GHG emissions are primarily a function of fuel combusted, startup emission rates have been assumed to be equivalent on a lb/MMBtu basis, to GHG emissions during normal operations. These startup emissions have been conservatively estimated to include shutdown as well, which has a very short duration.

Each turbine is assumed to consume 265 MMBtu of fuel during startup*
* from vendor data

Number of Start-ups (per turbine) 300
Total Number of Start-ups 900

	Emission Factor (lb/MMBtu)	Per Turbine		Total Start-up Emissions for All 3 Turbines		in CO_2e (tpy)
		lbs per Start	tons per Start	(lbs)	(tons)	
CO_2	118.9	31,509	15.75	28,357,650	14,179	**14,179**
CH_4	0.0022	0.58	0.00	525	0.26	**6**
N_2O	0.00022	0.06	0.00	52	0.03	**8**
CO_2e	119.01	31,539	15.77	28,384,934	14,192	**14,192**

Total Turbine GHG Emissions

	Normal Operations (tpy)	Start-ups (tpy)	TOTAL Emissions (tpy)	**in CO_2e (tpy)**
CO_2	947,930	14,179	962,109	**962,109**
CH_4	18	0	17.80	**374**
N_2O	2	0	1.78	**552**
CO_2e	948,842	14,192	963,035	**963,035**

Indeck Wharton
Siemens Turbine
GHG Emission Calcs

Emissions During Normal Operations

Assumptions **(For Each Turbine)**:

Max Turbine Heat Rating (HHV)[a]	2,357 MMBtu/hr	
Gross Output[a]	227,445 kW-hr	
Heat Rate	10,363 BTU/kW-hr	
Annual Capacity	2,500 hrs/yr	
Maximum Annual Heat Input	5,892,500 MMBtu/yr	(including SUSD)
Assumed HHV for Natural Gas	1,025 Btu/cf	
Proposed Output Based Emission Limit[b]	0.67 tons CO_2/MWh	

	Emission Factor	Per Turbine		All 3 Turbines		
	lb/MMBtu	lb/hr	tpy	lb/hr	tpy	**in CO_2e**
CO_2	118.9 - c	280,247	350,309	840,742	1,050,927	**1,050,927**
CH_4	0.0022 - d	5.19	6.48	15.56	19.45	**408**
N_2O	0.00022 - d	0.52	0.65	1.56	1.94	**603**
CO_2e	119.01 - e	280,517	350,646	841,551	1,051,939	**1,051,939**

a - from Siemens performance spreadsheet - 100% load, 70°F, HHV
b - includes an 8.5% increase over initial ISO-corrected rate as described in Section 5.2.5 of Application
c - Equation G-4 in Appendix G of 40 CFR Part 75
d - from Table C-2 of 40 CFR Part 98
e - Sum of CO_2, CH_4 and N_2O. CH_4 assumed to have 21 and N2O assumed to have 310 times the heat trapping capability of CO_2

Startup Emissions

Since GHG emissions are primarily a function of fuel combusted, startup emission rates have been assumed to be equivalent on a lb/MMBtu basis, to GHG emissions during normal operations. These startup emissions have been conservatively estimated to include shutdown as well, which has a very short duration.

Each turbine is assumed to consume 440.5 MMBtu of fuel during startup*

* from vendor data

Number of Start-ups (per turbine) 300
Total Number of Start-ups 900

	Emission Factor (lb/MMBtu)	Per Turbine		Total Start-up Emissions for All 3 Turbines		
		lbs per Start	tons per Start	(lbs)	(tons)	**in CO_2e (tpy)**
CO_2	118.9	52,375	26.19	47,137,905	23,569	**23,569**
CH_4	0.0022	0.97	0.00	872	0.44	**9**
N_2O	0.00022	0.10	0.00	87	0.04	**14**
CO_2e	119.01	52,426	26.21	47,183,259	23,592	**23,592**

Total Turbine GHG Emissions

	Normal Operations (tpy)	Start-ups (tpy)	TOTAL Emissions (tpy)	**in CO_2e (tpy)**
CO_2	1,050,927	23,569	1,074,496.33	**1,074,496**
CH_4	19	0.4	19.88	**418**
N_2O	2	0.0	1.99	**616**
CO_2e	1,051,939	23,592	1,075,530.16	**1,075,530**

Indeck Wharton
Emergency Diesel Generator
GHG Emission Calcs

Assumptions

Fuel heat content*	140,000 btu/gal
Max hourly fuel usage*	42.7 gal/hr
Max EDG Heat Rating (based on max fuel usage shown on engine spec sheet)	6.0 MMBtu/hr
Future Annual Capacity assumed to be	500 hrs/yr
Maximum Annual Heat Input	2,989 MMBtu/yr

	lb/MMBtu	lb/hr	tpy	**in CO_2e**
CO_2	162.3 - a	970.23	242.56	**242.6**
CH_4	0.0066 - b	0.04	0.01	**0.2**
N_2O	0.0013 - b	0.01	0.00	**0.6**
CO_2e	162.84 - c	973.47	243.37	**243.37**

a - Equation G-4 in Appendix G of 40 CFR Part 75

b - from Table C-2 of 40 CFR Part 98

c - Sum of CO_2, CH_4 and N_2O. CH_4 assumed to have 21 and N_2O assumed to have 310 times the heat trapping capability of CO_2

Indeck Warton
Fire Pump
GHG Emission Calcs

Assumptions

Fuel heat content	140,000 btu/gal
Max hourly fuel usage*	9 gal/hr
Max EDG Heat Rating (based on max fuel usage shown on engine spec sheet)	1.3 MMBtu/hr
Future Annual Capacity assumed to be	300 hrs/yr
Maximum Annual Heat Input	378 MMBtu/yr

	lb/MMBtu	lb/hr	tpy	**in CO_2e**
CO_2	162.3 - a	204.50	30.67	**30.7**
CH_4	0.0066 - b	0.01	0.00	**0.03**
N_2O	0.0013 - b	0.00	0.00	**0.1**
CO_2e	162.84 - c	205.18	30.78	**30.78**

a - Equation G-4 in Appendix G of 40 CFR Part 75

b - from Table C-2 of 40 CFR Part 98

c - Sum of CO_2, CH_4 and N_2O. CH_4 assumed to have 21 and N_2O assumed to have 310 times the heat trapping capability of CO_2

Indeck Warton
Pipeline Heater
GHG Emission Calcs

<u>Assumptions</u>

Max Pipeline Heater Heat Rating	3	MMBtu/hr
Future Annual Capacity assumed to be *includes hours for startups*	3,500	hrs/yr
Maximum Annual Heat Input	10,500	MMBtu/yr
Assumed HHV for Natural Gas	1,020	Btu/cf

	lb/MMBtu	lb/hr	tpy
CO_2	118.9 - a	356.70	624.23
CH_4	0.0022 - b	0.01	0.01
N_2O	0.00022 - b	0.00	0.00
CO_2e	119.01 - c	357.04	624.83

a - Equation G-4 in Appendix G of 40 CFR Part 75

b - from Table C-2 of 40 CFR Part 98

c - Sum of CO_2, CH_4 and N_2O. CH_4 assumed to have 21 and N_2O assumed to have 310 times the heat trapping capabilities of CO_2.

Indeck Warton
Pipeline Fugitives
GHG Emission Calcs

Annual Hours of Operation	3,500
includes hours for startups	
CH_4 constituent of the Nat Gas	95.97%
CO_2 constituent of the Nat Gas	0.53%

Component	No. of Components	Emission Factor (lb/hr-component)	Gas Pipeline Fugitive Hourly CH_4 Emissions (lb/hr)	Gas Pipeline Fugitive Annual CH_4 Emissions (tpy)	Gas Pipeline Fugitive Hourly CO_2 Emissions (lb/hr)	Gas Pipeline Fugitive Annual CO_2 Emissions (tpy)	Hourly Potential CO_2e Emissions (lb/hr)	Annual Potential CO_2e Emissions (tpy)
Valves	103	0.00992	0.98	1.72	0.005	0.01	20.60	36.05
Flanges	309	0.00086	0.26	0.45	0.001	0.002	5.36	9.37
Pressure Relief Valves	10	0.0194	0.19	0.33	0.001	0.002	3.91	6.84
Connectors	570	0.00044	0.24	0.42	0.001	0.002	5.06	8.85
TOTAL			1.66	2.91	0.009	0.02	34.92	61.11

NOTE – emissions assume a GWP of 21 for the CH_4 emissions.

Indeck Warton
Circuit Breaker SF_6 Fugitive Emissions
GHG Emission Calcs

Circuit Breaker Description	Amount of SF_6 at Full Charge (lbs)	Number of Breakers	Annual Leak Rate (%)	Hourly SF_6 Potential Emissions (lbs/hr)	Annual SF_6 Potential Emissions (tpy)	Hourly CO_2e Potential Emissions (lbs/hr)	Annual CO_{2e} Potential Emissions (tpy)
Generator Circuit Breakers	24.2	3	0.5	0.00004	0.0002	0.99	4.34
HV Power Circuit Breakers	550	11	0.5	0.0035	0.015	82.53	361.49
TOTAL		14		0.0035	0.015	83.52	365.83

NOTE – emissions assume a GWP of 23,900 for the CO_2e emissions.

Indeck Wharton
Combustion Turbine Project
GHG Emission Totals

GE Turbine Scenario

	Hourly Emissions (lbs/hr)								
	Unit 1	Unit 2	Unit 3	EDG	FP	Pipeline Htr	Gas Piping Fugitives	Circuit Breaker Fugitives	TOTAL
CO_2	263,482	263,482	263,482	970	204	357	0.01	-	791,979
CH_4	4.88	4.88	4.88	0.04	0.01	0.01	1.66	-	16.34
N_2O	0.49	0.49	0.49	0.01	0.00	0.00	-	-	1.47
SF_6	-	-	-	-	-	-	-	0.00	0.00
CO_2e	263,736	263,736	263,736	973.47	205.18	357.04	34.92	83.52	792,862

	Annual Emissions (tons/yr) - Includes Turbine Start-ups									
	Unit 1	Unit 2	Unit 3	Turb Starts	EDG	FP	Pipeline Htr	Gas Piping Fugitives	Circuit Breaker Fugitives	TOTAL
CO_2	315,977	315,977	315,977	14,179	242.56	30.67	624.23	0.02	-	963,007
CH_4	5.85	5.85	5.85	0.26	0.01	0.00	0.01	2.91	-	20.73
N_2O	0.58	0.58	0.58	0.03	0.00	0.00	0.00	-	-	1.78
SF_6	-	-	-	-	-	-	-	-	0.02	0.02
CO_2e	316,281	316,281	316,281	14,192	973.47	30.78	624.83	61.11	365.83	965,091

Siemens Turbine Scenario

	Hourly Emissions (lbs/hr)								
	Unit 1	Unit 2	Unit 3	EDG	FP	Pipeline Htr	Gas Piping Fugitives	Circuit Breaker Fugitives	TOTAL
CO_2	280,247	280,247	280,247	970	204	357	0.01	-	842,273
CH_4	5.19	5.19	5.19	0.04	0.01	0.01	1.66	-	17.27
N_2O	0.52	0.52	0.52	0.01	0.00	0.00	-	-	1.57
SF_6	-	-	-	-	-	-	-	0.00	0.00
CO_2e	280,517	280,517	280,517	973.47	205.18	357.04	34.92	83.52	843,205

	Annual Emissions (tons/yr) - Includes Turbine Start-ups									
	Unit 1	Unit 2	Unit 3	Turb Starts	EDG	FP	Pipeline Htr	Gas Piping Fugitives	Circuit Breaker Fugitives	TOTAL
CO_2	350,309	350,309	350,309	23,569	242.56	30.67	624.23	0.02	-	1,075,394
CH_4	6.48	6.48	6.48	0.44	0.01	0.00	0.01	2.91	-	22.81
N_2O	0.65	0.65	0.65	0.04	0.00	0.00	0.00	-	-	1.99
SF_6	-	-	-	-	-	-	-	-	0.02	0.02
CO_2e	350,646	350,646	350,646	23,592	243.37	30.78	624.83	61.11	365.83	1,076,856