June 26, 2013 via electronic mail

Ms. Melanie Magee
Greenhouse Gas Permit Contact
U.S. EPA Region 6, (6PD-R)
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: Greenhouse Gas Permit Application
Invenergy Thermal Development LLC
Ector County Energy Center
Goldsmith, Ector County, Texas

Dear Ms. Magee:

Invenergy Thermal Development LLC (Invenergy) plans to construct a simple cycle power generation facility in Goldsmith, Ector County, Texas.

This letter transmits the application for a GHG PSD permit which includes the Biological Assessment (BA) and the Cultural Resources Assessment.

Should you have any questions regarding this application, please contact me at bosborne@zephyrenv.com, or 512-579-3815, or Mr. Matthew Thornton of Invenergy Thermal Development LLC, at mthornton@invenergyllc.com at 312-582-1527.

Sincerely,
Zephyr Environmental Corporation

Bryan Osborne
Project Manager

Enclosures

cc: Mr. Jeff Robinson, EPA Region 6 via certified mail 7012 3050 0001 4138 3147
Mr. Dan Ewan, Invenergy LLC
Mr. Matt Thornton, Invenergy LLC
Mr. Mike Wilson, TCEQ Air Permits via certified mail 7012 3050 0001 4138 3130

PREVENTION OF SIGNIFICANT DETERIORATION GREENHOUSE GAS PERMIT APPLICATION FOR A SIMPLE-CYCLE POWER PLANT AT THE ECTOR COUNTY ENERGY CENTER ECTOR COUNTY, TEXAS

SUBMITTED TO:

ENVIRONMENTAL PROTECTION AGENCY
REGION 6
MULTIMEDIA PLANNING AND PERMITTING DIVISION
FOUNTAIN PLACE 12TH FLOOR, SUITE 1200
1445 ROSS AVENUE
DALLAS, TEXAS 75202-2733

SUBMITTED BY:

INVENERGY THERMAL DEVELOPMENT LLC
1 S. WACKER DR.
SUITE 1900
CHICAGO, IL 60606

Zephyr Environmental Corporation
STATE OF TEXAS
B.G BREEZE
86204
LICENSED
PROFESSIONAL ENGINEER
F-102
6/20/13

PREPARED BY:

ZEPHYR ENVIRONMENTAL CORPORATION
TEXAS REGISTERED ENGINEERING FIRM F-102
2600 VIA FORTUNA, SUITE 450
AUSTIN, TEXAS 78746

JUNE 2013

zephyr

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APPENDICES

1.0 INTRODUCTION

Invenergy Thermal Development LLC (Invenergy) is hereby submitting this application for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) air quality permit to construct and operate two new simple-cycle electric generating units at the Ector County Energy Center (ECEC), located approximately 20 miles northwest of Odessa in Ector County, Texas.

The proposed project will consist of two natural gas-fired simple-cycle combustion turbines, each exhausting to an associated stack. The combustion turbines to be installed at the site will be either the General Electric Model 7FA.03 or the General Electric Model 7FA.05 variants, with a nominal base-load gross electric power output of approximately 165 MW (model .03) or 193 MW (model .05) each.

In the case of the ECEC, the use of a combined-cycle design is not practical due to the length of time it would require to start up these units since the load requirements that would be met by this facility are typically immediate and require quick response. Once started up, the demand for this power is typically only short-term and so the source would normally be shut-down when the demand is no longer present.

On June 3, 2010, the EPA published final rules for permitting sources of GHGs under the PSD and Title V air permitting programs, known as the GHG Tailoring Rule.[1] After July 1, 2011, new sources with the potential to emit more than 100,000 tons/yr of GHGs and modifications increasing GHG emissions more than 75,000 tons/yr on a carbon dioxide equivalent (CO_2e) basis at existing major sources are subject to GHG PSD review, regardless of whether PSD was triggered for other pollutants.

On December 23, 2010, EPA issued a Federal Implementation Plan (FIP) authorizing EPA to issue PSD permits in Texas for GHG sources until Texas submits the required SIP revision for GHG permitting and it is approved by EPA.[2]

The ECEC project for the construction of two simple-cycle combustion turbine units triggers PSD review for GHG regulated pollutants because the installation of the ECEC will produce GHG emissions of more than 100,000 tons/yr. Included in this application are a project scope description, GHG emissions calculations, and a GHG Best Available Control Technology (BACT) analysis. Also included are a Biological Assessment (BA) and cultural resources report of the areas surrounding the facility.

[1] 75 FR 31514 (June 3, 2010).
[2] 75 FR 81874 (Dec. 29, 2010).

Texas Commission on Environmental Quality
Form PI-1 General Application for
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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: Invenergy Thermal Development LLC		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: Mr. Jim Shield		
Title: Vice President, Thermal Development		
Mailing Address: 1 S. Wacker Dr., Suite 1900		
City: Chicago	State: IL	ZIP Code: 60606
Telephone No.: 312-582-1440	Fax No.: 312-506-1455	E-mail Address: jshield@invenergyllc.com
C. Technical Contact Name: Mr. Matthew Thornton		
Title: Business Development Manager		
Company Name: Invenergy Thermal Development, LLC		
Mailing Address: 1 S. Wacker., Suite 1900		
City: Chicago	State: IL	ZIP Code: 60606
Telephone No.: 312-582-1527	Fax No.: 312-506-1455	E-mail Address: mthornton@invenergyllc.com
D. Site Name: Ector County Energy Center		
E. Area Name/Type of Facility: Electric Utility		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Electric Generation		
Principal Standard Industrial Classification Code (SIC): 4911		
Principal North American Industry Classification System (NAICS): 221112		
G. Projected Start of Construction Date: 6/1/2014		
Projected Start of Operation Date: 6/1/2015		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: From Goldsmith, drive E on Hwy. 158. Turn N on Holt Road. Turn W on SW 3601. Facility is ~3mi on r.		
City/Town: Goldsmith	County: Ector	ZIP Code: 79741
Latitude (nearest second): 32° 04' 10" N	Longitude (nearest second): 102° 35' 08" W	

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).		☒ YES ☐ NO
K.	Customer Reference Number (CN): CN604326009	
L.	Regulated Entity Number (RN): RN106754989	
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 ☒ 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 ☒ NO
C.	Number of New Jobs: TBD	
D.	Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Kel Seliger		District No.: 31
State Representative: Tryon D. Lewis		District No.: 81
III.	**Type of Permit Action Requested**	
A.	Mark the appropriate box indicating what type of action is requested.	
☒ 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)*	
☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit		
☒ 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 ☒ NO

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 ☒ 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:		
City:	County:	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.	☐ YES ☐ NO
4.	Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?	☐ YES ☐ 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 ☐ 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
☒ To be Determined		☐ None

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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	☐ 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?	☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ 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 ☒ 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 ☒ 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 ☐ NO
2. Is there a new air contaminant in this application?	☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
F. List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***	
Volatile Organic Compounds (VOC): 41.51	
Sulfur Dioxide (SO2): 69.8	
Carbon Monoxide (CO): 298.35	
Nitrogen Oxides (NOx): 160.88	
Particulate Matter (PM): 67.13	
PM 10 microns or less (PM10): 67.13	
PM 2.5 microns or less (PM2.5): 67.13	
Lead (Pb):	
Hazardous Air Pollutants (HAPs): <10 tpy for individual HAP and <25 tpy for all HAPs	
Other speciated air contaminants not listed above: (H2SO4): 31.80	

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TCEQ

V. Public Notice Information *(complete if applicable)*		
A. Public Notice Contact Name: Mr. Matthew Thornton		
Title: Business Development Manager		
Mailing Address: 1 S. Wacker Dr., Suite 1900		
City: Chicago	State: IL	ZIP Code: 60606
B. Name of the Public Place: Ector County Library		
Physical Address *(No P.O. Boxes)*: 321 W 5th St		
City: Odessa	County: Ector	ZIP Code: 79761
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: Susan M. Redford		
Mailing Address: 300 North Grant, Room 227		
City: Odessa	State: TX	ZIP Code: 79761
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***	☐ YES ☐ 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: Mayor David Turner		
Mailing Address: P.O. Box 4398		
City: Odessa	State: TX	ZIP Code: 79760
Name of the Indian Governing Body:		
Mailing Address:		
City:	State:	ZIP Code:

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): Leslie Thiess, 801 S. Fillmore Street, Suite 500, Amarillo, TX 79101		
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?	Spanish	
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 ☒ NO
B.	Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C.	Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D.	Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☒ NO
VII.	**Technical Information**	
A.	The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***	
1.	☒ Current Area Map	
2.	☒ Plot Plan	
3.	☒ Existing Authorizations	
4.	☒ Process Flow Diagram	
5.	☒ Process Description	
6.	☒ Maximum Emissions Data and Calculations	
7.	☒ Air Permit Application Tables	
a.	☒ 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?	☐ YES ☒ NO

VII.	**Technical Information**			
C.	Maximum Operating Schedule:			
Hour(s): 24	Day(s): 7	Week(s): 52	Year(s):	
Seasonal Operation? If Yes, please describe in the space provide below.				☐ YES ☒ NO
D.	Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☐ YES ☒ 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 ☒ NO
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?			☐ YES ☒ 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?			☒ YES ☐ NO
B.	Will emissions of significant air contaminants from the facility be measured?			☒ YES ☐ NO
C.	Is the Best Available Control Technology (BACT) demonstration attached?			☒ 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?			☒ 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?			☒ YES ☐ NO
B.	Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?			☐ 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.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X.	**Professional Engineer (P.E.) Seal**	
Is the estimated capital cost of the project greater than $2 million dollars?		☒ 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: $
Paid online?		☐ YES ☐ NO
Company name on check:		
Is a copy of the check or money order attached to the original submittal of this application?		☐ YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?		☐ 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:	
Signature:______________________________ *Original Signature Required*	
Date:	

PRINT FORM RESET FORM

2.0 PROJECT SCOPE

2.1 INTRODUCTION

With this application, Invenergy is seeking authorization for a simple-cycle electric generating project at the ECEC, in Ector County, Texas; which will operate for a maximum of 2500 hours per unit per year. The power generating equipment and ancillary equipment that will be sources of GHG emissions at the site are listed below:

- Two identical simple-cycle, natural gas-fired combustion turbines equipped with lean pre-mix low-NO_x combustors
- A natural gas-fired fuel heater for natural gas supply to the combustion turbines
- One diesel fuel-fired emergency fire-water pump engine
- Electrical equipment insulated with sulfur hexafluoride (SF_6)
- Natural gas piping, handling and metering equipment

A process flow diagram is included at the end of this section.

The business purpose of the ECEC is to generate 165-386 megawatts (MW), of gross electrical power (in peaking service) near the City of Odessa in an efficient manner while increasing the reliability of the electrical supply for the State of Texas.

Pipeline natural gas is chosen as the only fuel for the combustion turbines due to local availability of fuel and infrastructure to support delivery of the fuel to the facility in adequate volume and pressure.

2.2 COMBUSTION TURBINE GENERATORS

The combustion turbine generators (CTGs) will burn pipeline-quality natural gas in order to drive electrical generators. The main components of each CTG turbine consist of a compressor, combustor, expansion turbine, and generator. The compressor pressurizes the inlet combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the expansion turbine where the gases expand as they pass through the turbine section which generates torque that drives a shaft to power an electric generator. The temperature of the inlet air to the CTGs proposed for the ECEC will occasionally be lowered using evaporative cooling to increase the mass of air flowing through the turbines and achieve maximum turbine power output on days with warm to hot ambient conditions.

The combustion turbines that are under consideration for the site will be either the General Electric Model 7FA.03 or the General Electric Model 7FA.05 variants, with a nominal base-load gross electric power output of approximately 165 MW (model .03) or 193 MW (model .05) each.

The exhaust gases from each combustion turbines will be routed to the respective exhaust stacks (EPNs: CT1 and CT2).

The intended use of the proposed generating units is to provide peaking power for sale onto the Electrical Reliability Council of Texas (ERCOT) grid and so the units may operate within a range of load to respond to changes in system power requirements and/or stability.

2.3 NATURAL GAS-FIRED DEW-POINT HEATER

One natural gas-fired dew-point heater (EPN: DPT HTR) will be provided to ensure that the natural gas that is supplied to the combustion turbines has the proper amount of superheat to avoid possible condensate material from damaging the combustion turbine combustor sections. The dew-point heater will have a maximum heat input of 9 MMBtu/hr and will burn pipeline-quality natural gas. The dew-point heater will be in operation whenever one or both of the combustion turbines are in operation. Operations are anticipated to be for a maximum of 5000 hours per year.

2.4 DIESEL-FIRED EMERGENCY FIRE-WATER PUMP

An approximate 250-horsepower diesel-fired emergency fire-water pump will be installed to be used only during emergency situations to operate the plant's fire-fighting equipment (EPN: FWP). However, the fire-water pump will be operated (typically for a few hours) on a monthly basis to maintain the integrity and operational readiness of the equipment. Annual hours of operation are anticipated to be less than 100 hours per year during non-emergency situations.

2.5 NATURAL GAS / FUEL GAS PIPING

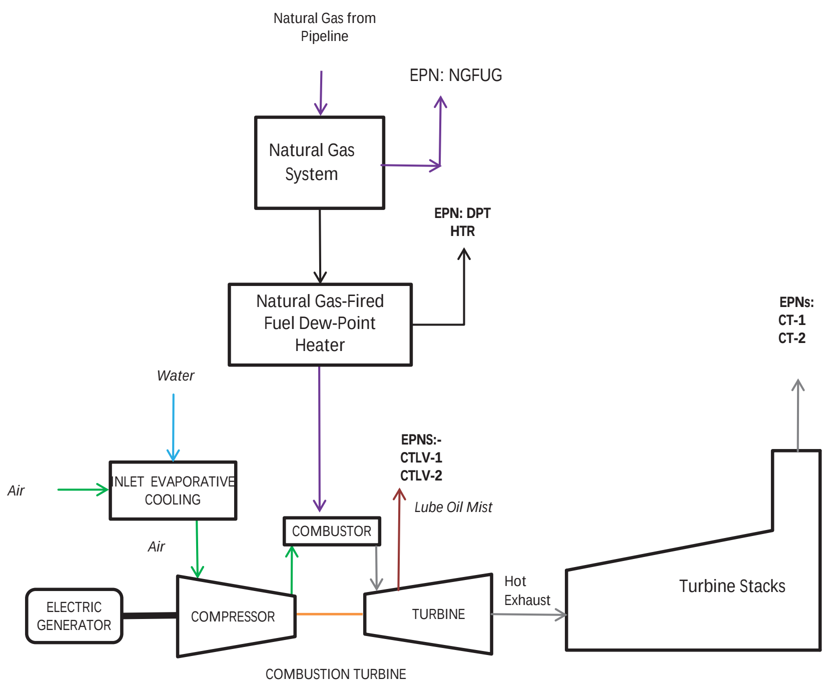
Natural gas will be delivered to the site via pipeline and then metered and piped to the combustion turbines. Project fugitive emissions from the gas piping components associated with the new CTG units will include emissions of methane (CH_4) and carbon dioxide (CO_2). Fugitive emissions of natural gas are designated as EPN: NGFUG.

2.6 ELECTRICAL EQUIPMENT INSULATED WITH SULFUR HEXAFLUORIDE (SF_6)

The generator circuit breakers associated with the proposed units will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 240 lbs of SF_6. Fugitive emissions of SF_6 are designated as EPN: SF6FUG.

The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of “quenching and cooling” SF_6 gas.

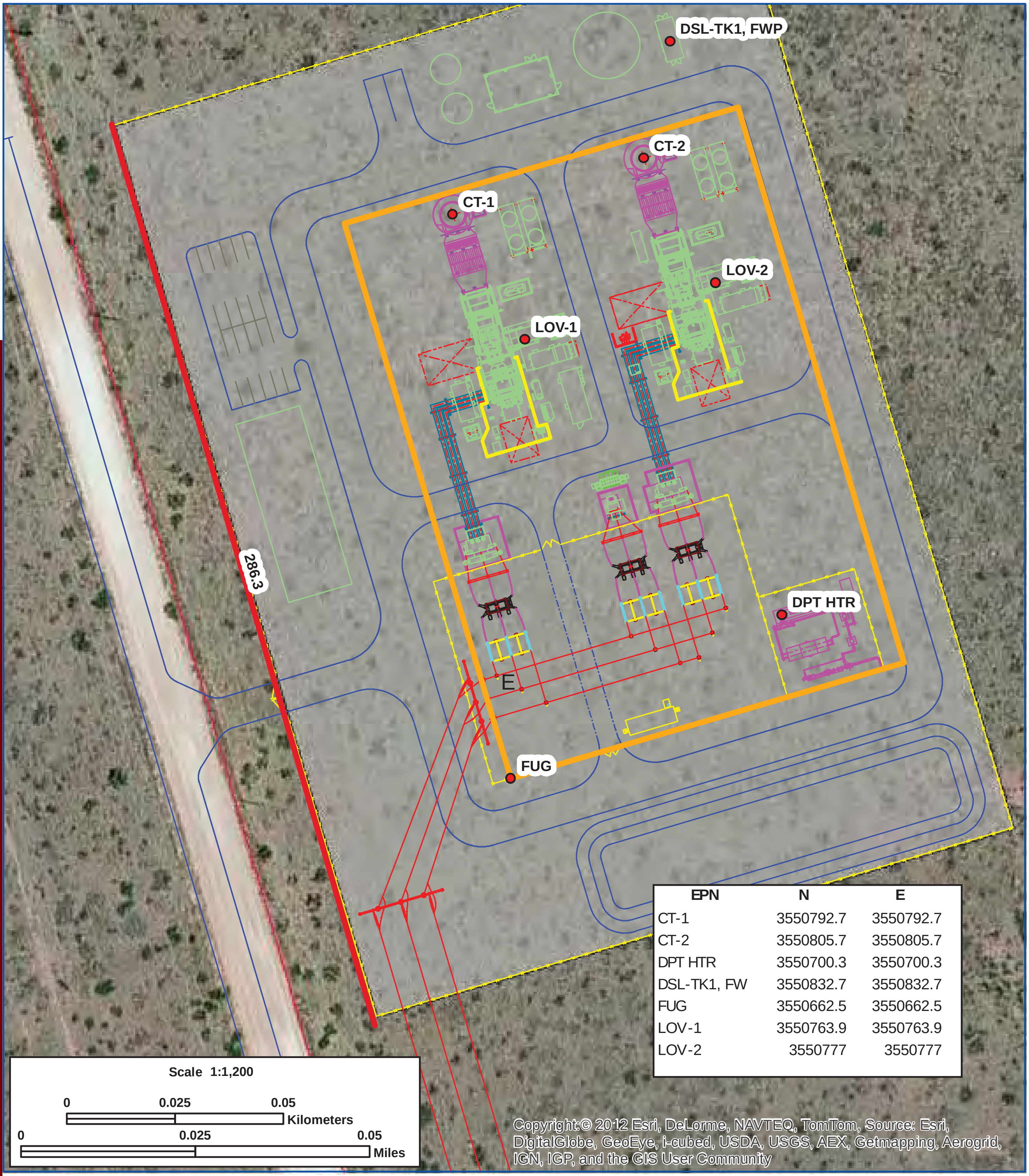
PROCESS FLOW DIAGRAM



MISC. EPNs:
FWP
MSSFUG
LOFUG

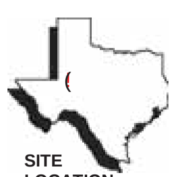
Ector County Energy Center			FIGURE VII.A.4 PROCESS FLOW DIAGRAM		
Permit Application			Filename: ECEC PFD.xls		
zephyr	Drawn by: B.Breeze	Checked by: B. Osborne	Project No.: 13003.001	Date: 3/22/2013	Sheet: 1 of 1

PLOT PLAN



EPN	N	E
CT-1	3550792.7	3550792.7
CT-2	3550805.7	3550805.7
DPT HTR	3550700.3	3550700.3
DSL-TK1, FW	3550832.7	3550832.7
FUG	3550662.5	3550662.5
LOV-1	3550763.9	3550763.9
LOV-2	3550777	3550777

Datum:
GCS NAD 1983
Map Sources: ESRI
Streets & Bing Hybrid Basemap,
Invenergy LLC



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AREA MAP

Peaker Project Area

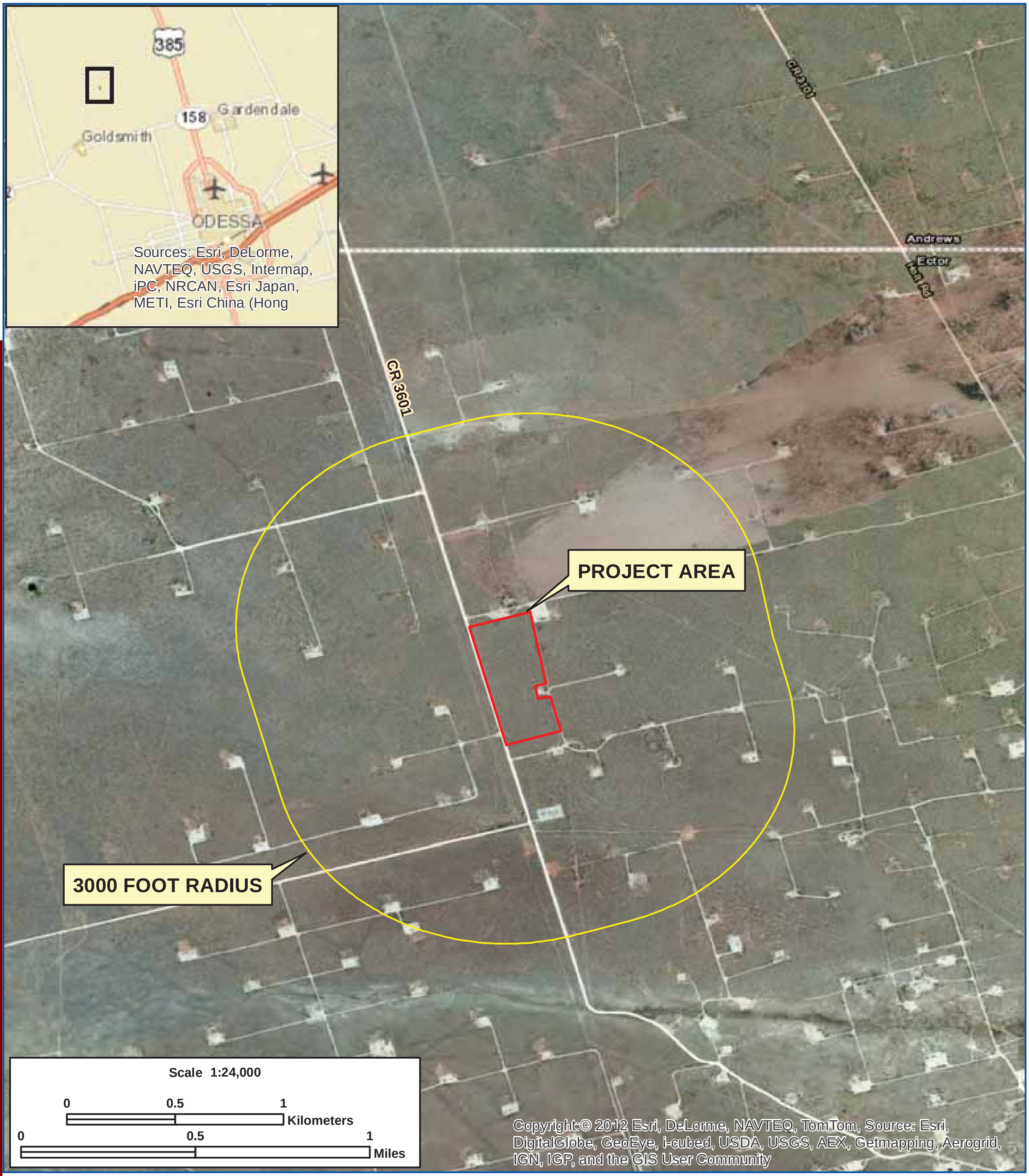
Invenergy LLC

Ector County, Texas

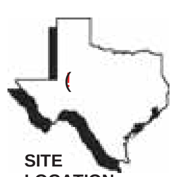
H:\Invenergy, LLC\GIS\PDF

Drafted By:	Reviewed By:	Project No.:	Date:
J. Knowles	B. Osborne	13003.001	02.28.2013

AREA MAP



Datum:
GCS NAD 1983
Map Sources: ESRI
Streets & Bing Hybrid Basemap,
Invenergy LLC



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AREA MAP

ECTOR COUNTY ENERGY CENTER

Invenergy LLC

Ector County, Texas

H:\Invenergy, LLC\GIS\PDF

Drafted By:	Reviewed By:	Project No.:	Date:
J. Knowles	B. Osborne	13003.001	03.25.2013

3.0 GHG EMISSION CALCULATIONS

3.1 GHG EMISSIONS FROM THE SIMPLE-CYCLE COMBUSTION TURBINES

GHG emissions for the combustion turbines are calculated in accordance with the procedures in the Mandatory Greenhouse Reporting Rules, Subpart D – Electric Generation.[3] Annual CO_2 emissions are calculated using the methodology in equation G-4 of the Acid Rain Rules.[4]

$$W_{CO_2} = \left(\frac{F_C \times H \times U_f \times MW_{CO_2}}{2000} \right) \qquad (Eq.\ G\text{-}4)$$

Where:

W_{CO2} = CO_2 emitted from combustion, tons/yr

MW_{CO2} = Molecular weight of carbon dioxide, 44.0 lb/lb-mole

F_c = Carbon based F-factor, 1,040 scf/MMBtu for natural gas

H = Annual heat input in MMBtu

U_f = 1/385 scf CO_2/lb-mole at 14.7 psia and 68 °F.

Emissions of CH_4 and nitrous oxide (N_2O) are calculated using the emission factors (kg/MMBtu) for natural gas combustion from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[5] The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.

Calculations of GHG emissions from the simple-cycle combustion turbines are presented on Table 3-2 for the two variants.

Startup Emissions from the simple-cycle combustion turbines are presented on Table 3-3.

3.2 NATURAL GAS-FIRED DEW-POINT HEATER

CO_2 emissions from the natural gas-fired dew-heater are calculated using the emission factors (kg/MMBtu) for natural gas from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[6] CH_4 and N_2O emissions from the dew-point heater are calculated using the emission factors

[3] 40 C.F.R. 98, Subpart D – *Electricity Generation*
[4] 40 C.F.R. 75, Appendix G – *Determination of CO_2 Emissions*
[5] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-2
[6] *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-1

(kg/MMBtu) for natural gas from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[7] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[8]

Calculations of GHG emissions from the dew-point heater are presented on Table 3-4.

3.3 GHG EMISSIONS FROM NATURAL GAS PIPING FUGITIVES AND NATURAL GAS MAINTENANCE AND STARTUP/SHUTDOWN RELATED RELEASES

GHG emission calculations for natural gas/fuel gas piping component fugitive emissions are based on emission factors from Table W-1A of the "2012 Technical Corrections, Clarifying and Other Amendments to the Greenhouse Gas Reporting Rule, and Confidentiality Determinations for Certain Data Elements of the Fluorinated Gas Source Category" which was signed on August 3, 2012[9]. The concentrations of CH_4 and CO_2 in the natural gas are based on a typical natural gas analysis. Since the CH_4 and CO_2 content of natural gas is variable, the concentrations of CH_4 and CO_2 from the typical natural gas analysis are used as a worst case estimate. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[10]

GHG emission calculations for releases of natural gas related to piping maintenance and turbine startup/shutdowns are calculated using the same CH_4 and CO_2 concentrations as natural gas/fuel gas piping fugitives.

Calculations of GHG emissions from natural gas piping fugitives are presented on Table 3-5. Calculations of GHG emissions from releases of natural gas related to piping maintenance and turbine startup/shutdown activities is presented on Table 3-6.

3.4 GHG EMISSIONS FROM DIESEL FIRED EMERGENCY FIRE-WATER PUMP

CO_2 emission calculations from the diesel-fired emergency fire-water pump engine are calculated using the emission factors (kg/MMBtu) for Distillate Fuel Oil No. 2 from Table C-1 of the Mandatory Greenhouse Gas Reporting Rules.[11] CH_4 and N_2O emissions from the diesel-fired engine are calculated using the emission factors (kg/MMBtu) for Petroleum from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[12] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[13]

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[7] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-2
[8] *Global Warming Potentials*, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.
[9] www.epa.gov/ghgreporting/reporters/notices/corrections.html#aug2012 (last visited December 11, 2012).
[10] *Global Warming Potentials*, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.
[11] *Default CO_2 Emission Factors and High Heat Values for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-1
[12] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 C.F.R. 98, Subpt. C, Tbl. C-2
[13] *Global Warming Potentials*, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.

Calculations of GHG emissions from the emergency fire-water pump engine are presented on Table 3-7.

3.5 GHG EMISSIONS FROM ELECTRICAL EQUIPMENT INSULATED WITH SF_6

SF_6 emissions from the new generator circuit breaker(s) and yard breaker associated with the proposed units are calculated using a predicted SF_6 annual leak rate of 0.5% by weight. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of the Mandatory Greenhouse Gas Reporting Rules.[14]

Calculations of GHG emissions from electrical equipment insulated with SF_6 are presented on Table 3-8.

[14] *Global Warming Potentials*, 40 C.F.R. Pt. 98, Subpt. A, Tbl. A-1.

TABLE 3-1 ANNUAL GHG EMISSION SUMMARY

Table 3-1
Plantwide GHG Emission Summary
Ector County Energy Center

Name	EPN	GHG Mass Emissions ton/yr	CO_2e ton/yr
Combustion Turbine 1	CT-1	283,408	283,681
Combustion Turbine 2	CT-2	283,408	283,681
Dewpoint Heater	DPT HTR	2,630	2,633
Natural Gas Fugitives	NGFUG	10	212
MSS Fugitives	MSS FUG	0.13	3
Fire Water Pump	FWP	5	5
SF_6 Insulated Equipment	SF6-FUG	0.0006	14
Sitewide Emissions:[1]		**286,054**	**286,548**

1. The sitewide emissions total uses the higher GHG emissions from the two gas turbine options.

TABLE 3-2 ANNUAL GHG EMISSION CALCULATIONS – GE 7FA SIMPLE-CYCLE COMBUSTION TURBINES

Table 3-2

GHG Annual Emission Calculations - Simple Cycle Combustion Turbine

Ector County Energy Center

EPN	Average Heat Input[1] (MMBtu/hr)	Annual Heat Input[2] (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[3]	GHG Mass Emissions[4] (tpy)	Global Warming Potential[5]	CO_2e (tpy)
CT-1, CT-2 7FA.03 Variants	1,786	4,464,432	CO_2	118.86	265,315	1	265,315
			CH_4	2.2E-03	4.9	21	103.3
			N_2O	2.2E-04	0.5	310	152.6
CT-1, CT-2 7FA.05 Variants	1,908	4,768,881	CO_2	118.86	283,408	1	283,408
			CH_4	2.2E-03	5.3	21	110.4
			N_2O	2.2E-04	0.5	310	163.0

Note

1. *The average heat input is based on the HHV iso heat input at 100% load firing, at 65 ^oF ambient temperature.*
2. *Annual heat input based on 2,500 hours per year operation.*
3. *CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
4. *CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2000$

W_{CO2} = CO_2 *emitted from combustion, tons/yr*

F_c = *Carbon based F-factor,1040 scf/MMBtu*

H = Heat Input (MMBtu/yr)

U_f = *1/385 scf CO_2/lbmole at 14.7 psia and 68 ^oF*

MW_{CO2} = *Molecule weight of CO_2, 44.0 lb/lb-mole*

5. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

TABLE 3-3 STARTUP GHG EMISSION CALCULATIONS - GE 7FA TURBINES

Table 3-3
Startup GHG Emission Calculations - Simple Cycle Combustion Turbine
Ector County Energy Center

Max Hourly GHG Emissions From Turbine

EPN	Max Hourly Heat Input (MMBtu/hr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions[3] (ton/hr)	Global Warming Potential[4]	CO_2e (ton/hr)
CT-1, CT-2 7FA.03 Variants	1,880.7	CO_2	118.86	112	1	112
		CH_4	2.2E-03	0.0021	21	0.0435
		N_2O	2.2E-04	0.0002	310	0.0643
CT-1, CT-2 7FA.05 Variants	1,944.7	CO_2	118.86	116	1	116
		CH_4	2.2E-03	0.0021	21	0.0450
		N_2O	2.2E-04	0.0002	310	0.0665

Startup/Shutdown Hourly GHG Emissions From Turbine

EPN	Heat Input During Startup[1] (MMBtu/hr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions[3] (ton/hr)	Global Warming Potential[4]	CO_2e (ton/hr)
CT-1, CT-2 7FA.03 Variants	1,320.1	CO_2	118.86	78	1	78
		CH_4	2.2E-03	0.0015	21	0.0306
		N_2O	2.2E-04	0.0001	310	0.0451
CT-1, CT-2 7FA.05 Variants	1,241.8	CO_2	118.86	74	1	74
		CH_4	2.2E-03	0.0014	21	0.0287
		N_2O	2.2E-04	0.0001	310	0.0424

Note

1. *The hourly heat input data is the maximum heat rate from GE Performance Data for low load (50%) conditions*
2. CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.
3. CO_2 *emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2000$

W_{CO2} = CO_2 *emitted from combustion, tons/hr*

F_c = *Carbon based F-factor,1040 scf/MMBtu*

H = Heat Input (MMBtu/hr)

U_f = *1/385 scf* CO_2*/lbmole at 14.7 psia and 68* ^oF

MW_{CO2} = *Molecule weight of* CO_2*, 44.0 lb/lb-mole*

4. *Global Warming Potential factors from Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

TABLE 3-4 GHG EMISSION CALCULATIONS – NATURAL GAS-FIRED DEW-POINT HEATER

Table 3-4
GHG Emission Calculations - Dewpoint Heater
Ector County Energy Center

GHG Potential To Emit Emissions From Natural Gas-Fired Dewpoint Heater

EPN	Maximum Heat Input[1] (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions (tpy)	Global Warming Potential[3]	CO_2e (tpy)
DPT HTR	45,000	CO_2	116.89	2,630	1	2,630
		CH_4	2.2E-03	0.05	21	1.0
		N_2O	2.2E-04	0.005	310	1.5
			Total:	**2,630**		**2,633**

Note

1. *Annual fuel use and heating value of natural gas from Table A-10 State/PSD air permit application*
2. *Factors based on Table C-1 and C-2 of 40 CFR Part 98, Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

TABLE 3-5 GHG EMISSION CALCULATIONS - NATURAL GAS PIPING FUGITIVES

Table 3-5
GHG Emission Calculations - Natural Gas Piping Fugitives
Ector County Energy Center

GHG Emissions Contribution From Fugitive Natural Gas Piping Components

EPN	Source Type	Fluid State	Count	Emission Factor[1] (scf/hr/comp)	CO_2[2] (tpy)	Methane[3] (tpy)	**Total (tpy)**
NGFUG	Valves	Gas/Vapor	300	0.121	0.084	6.313	-
	Flanges	Gas/Vapor	1,200	0.017	0.047	3.548	-
	Relief Valves	Gas/Vapor	5	0.193	0.002	0.168	-
	Open-Ended Lines	Gas/Vapor	10	0.031	0.0007	0.0539	-
	Compressors	Gas/Vapor	3	0.003	0.000021	0.00157	-
GHG Mass-Based Emissions					0.134	10.08	**10.22**
Global Warming Potential[4]					1	21	-
CO_2e Emissions					0.134	211.78	**211.91**

Note

1. *Emission factors from Table W-1A of 40 CFR 98 Mandatory Greenhouse Gas Reporting published in the May 21, 2012 Technical Corrections*
2. *CO_2 emissions based on vol% of CO_2 in natural gas* *0.46%*
3. *CH_4 emissions based on vol% of CH_4 in natural gas* *95.3%*
4. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Example calculation:

300 valves	0.123 scf gas	0.0046 scf CO2	lbmole	44 lb CO_2	8760 hr	ton =	0.08 ton/yr
	hr * valve	scf gas	385 scf	lbmole	yr	2000 lb	

TABLE 3-6 GASEOUS FUEL VENTING DURING TURBINE SHUTDOWN/MAINTENANCE AND SMALL EQUIPMENT AND FUGITIVE COMPONENT REPAIR/REPLACEMENT

TABLE 3-6

Gaseous Fuel Venting During Turbine Shutdown/Maintenance and

Small Equipment and Fugitive Component Repair/Replacement

Ector County Energy Center

Location	Initial Conditions			Final Conditions			Annual Emissions		
	Volume[1] (ft^3)	Press. (psig)	Temp. (°F)	Press. (psig)	Temp. (°F)	Volume[2] (scf)	CO_2[3] (tpy)	CH_4[4] (tpy)	**Total (tpy)**
Turbine Fuel Line Shutdown/Maintenance	138	600	50	0	68	6,710	0.0018	0.13	
Small Equipment/Fugitive Component Repair/Replacement	7	50	50	0	68	3	0.00000	0.00006	
GHG Mass-Based Emissions							0.0018	0.1330	**0.13**
Global Warming Potential[5]							1	21	
CO_2e Emissions							0.0018	2.8	**2.8**

1. Initial volume is calculated by multpilying the crossectional area by the length of pipe using the following formula: V_i = pi * [(diameter in inches/12)/2]^2 * length in feet = ft^3

2. Final volume calculated using ideal gas law $[(PV/ZT)_i = (PV/ZT)_f]$. $V_f = V_i\ (P_i/P_f)\ (T_f/T_i)\ (Z_f/Z_i)$, where Z is estimated using the following equation: $Z = 0.9994 - 0.0002P + 3E\text{-}08P^2$.

3. *CO_2* emissions based on vol% of CO_2 in natural gas — 0.46% from natural gas analysis

4. *CH_4 emissions based on vol% of CH_4 in natural gas* — 95.3% from natural gas analysis

5. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Example calculation:

$$\frac{6710\text{ scf Nat Gas}}{\text{yr}} \left| \frac{0.005\text{ scf CO2}}{\text{scf Nat Gas}} \right| \frac{\text{lbmole}}{385\text{ scf}} \left| \frac{44\text{ lb }CO_2}{\text{lbmole}} \right| \frac{\text{ton =}}{2000\text{ lb}} \right| = 0.0018\ \text{ton/yr } CO_2$$

TABLE 3-7 GHG EMISSION CALCULATIONS - EMERGENCY DIESEL FIRE-WATER PUMP ENGINE

Table 3-7
GHG Emission Calculations - Fire Water Pump Engine
Ector County Energy Center

GHG Emissions Contribution From Diesel Combustion In Fire Water Pump Engine

Assumptions:

Annual Operating Schedule:	100	hours/year
Power Rating:	250	hp
Max Hourly Fuel Use:	4.8	gal/hr
Heating Value of No. 2 Fuel Oil[1]:	0.138	MMBtu/gal
Max Hourly Heat Input:	0.7	MMBtu/hr
Annual Heat Input:	66.7	MMBtu/yr

EPN	Heat Input (MMBtu/yr)	Pollutant	Emission Factor (lb/MMBtu)[2]	GHG Mass Emissions (tpy)	Global Warming Potential[3]	CO_2e (tpy)
FWP	66.7	CO_2	163.05	5.44	1	5.44
		CH_4	6.6E-03	0.0002	21	0.005
		N_2O	1.3E-03	0.0000	310	0.014
			Total:	**5.44**		**5.46**

Calculation Procedure

Annual Emission Rate = annual heat Input X Emission Factor X 2.2 lbs/kg X Global Warming Potential / 2,000 lbs/ton

Note

1. *Default high heat value based on Table C-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
2. *GHG factors based on Tables C-1 and C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

TABLE 3-8 GHG EMISSION CALCULATIONS - ELECTRICAL EQUIPMENT INSULATED WITH SF6

Table 3-8

GHG Emission Calculations - Electrical Equipment Insulated With SF_6

Ector County Energy Center

Assumptions

Insulated circuit breaker SF_6 capacity:	240	lb
Estimated annual SF_6 leak rate:	0.5%	by weight
Estimated annual SF_6 mass emission rate:	0.0006	ton/yr
Global Warming Potential[1]:	23,900	
Estimated annual CO_2e emission rate:	14.3	ton/yr

Note

Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

4.0 PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY

Because the project emissions increase of GHG is greater than 100,000 ton/yr of CO2e, PSD is triggered for GHG emissions. The emissions netting analysis is documented on the attached TCEQ PSD netting tables: Table 1F and Table 2F. Note that this is a new greenfield site and, as such, there are no contemporaneous emission changes associated with the project. Also included in Appendix A is the "The GHG PSD APPLICABILITY FLOWCHART – NEW SOURCES" from the PSD and Title V Permitting Guidance for Greenhouse Gases.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

EPA's PSD rules define BACT as follows:

> *Best available control technology* means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the] 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.[15]

In the EPA guidance document titled *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA recommends the use of the Agency's five-step "top-down" BACT process to determine BACT for GHGs.[16] In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.

EPA has broken down this analytical process into the following five steps:

- Step 1: Identify all available control technologies
- Step 2: Eliminate technically infeasible options
- Step 3: Rank remaining control technologies

[15] 40 C.F.R. § 52.21(b)(12.)
[16] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, p. 18 (Nov. 2010).

- Step 4: Evaluate most effective controls and document results
- Step 5: Select the BACT.

5.1 BACT FOR THE SIMPLE-CYCLE COMBUSTION TURBINES

5.1.1 Step 1: Identify All Available Control Technologies

5.1.1.1 Inherently Lower-Emitting Processes/Practices/Designs

A summary of available, lower greenhouse gas emitting processes, practices, and designs for combustion turbine power generators is presented below. Although Invenergy is currently evaluating two different models of the GE 7FA turbine, the proposed energy efficiency processes, practices and designs discussed in Step 1 will be the same for both models of the turbines being considered. The BACT limits proposed in Step 5 are specific to each turbine model.

<u>5.1.1.1.1 Combustion Turbine Energy Efficiency Processes, Practices, and Designs</u>

Combustion Turbine Design

CO_2 is a product of combustion of fuel containing carbon, which is inherent in any power generation technology using fossil fuel. It is not possible to reduce the amount of CO_2 generated from combustion, as CO_2 is the essential product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by imperfect combustion. As such, there is no technology available that can effectively reduce CO_2 generation by adjusting the conditions in which combustion takes place.

The only effective means to reduce the amount of CO_2 generated by a fuel-burning power plant is to generate as much electric power as possible from the combustion, thereby reducing the amount of fuel needed to meet the plant's required power output. This result is obtained by using the most efficient generating technologies available, so that as much of the energy content of the fuel as possible goes into generating power.

Currently, the most efficient way to generate electricity from a natural gas fuel source is the use of a combined-cycle design. For fossil fuel technologies, efficiency ranges from approximately 30-50% (higher heating value [HHV]). A typical coal-fired Rankine cycle power plant has a base load efficiency of approximately 30% (HHV), while a modern F-Class natural gas fired combined cycle unit operating under optimal conditions has a base load efficiency of approximately 50% (HHV). The efficiency of the simple-cycle version of the GE F-Class turbines slated to be utilized at ECEC is approximately 36-38% under optimal conditions.

In the case of the ECEC, the use of a combined-cycle design is not practical due to the length of time it would require to start up these units since the load requirements that would be met by this facility are typically immediate and require quick response. Once started up, the demand for this power is typically only short-term and so the source would normally be shut-down when the demand is no longer present. These quick-start and short-term power needs will also eliminate Integrated Gasification Combined Cycle (IGCC) technology from consideration.

In addition to the high-efficiency primary components of a combustion turbine, there are a number of other design features employed within the turbine that can improve the overall efficiency of the machine. These additional features include those summarized below.

Periodic Burner Tuning
Modern F-Class combustion turbines have regularly scheduled maintenance programs. These maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. As the combustion turbine is operated, the unit experiences degradation and loss in performance. The combustion turbine maintenance program helps restore the recoverable lost performance. The maintenance program schedule is determined by the number of hours of operation and/or turbine starts. There are three basic maintenance levels, commonly referred to as combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to restore highly efficient low-emission operation.

Reduction in Heat Loss
Modern F-Class combustion turbines have high operating temperatures. The high operating temperatures are a result of the heat of compression in the compressor along with the fuel combustion in the burners. To minimize heat loss from the combustion turbine and protect the personnel and equipment around the machine, insulation blankets are applied to the combustion turbine casing. These blankets minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine.

Instrumentation and Controls
Modern F-Class combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital-type and is supplied with the combustion turbine. The distributed control system (DCS) controls all aspects of the turbine's operation, including the fuel feed and burner operations, to achieve efficient low-NO_X combustion. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency low-emission performance for full-load and part-load conditions.

5.1.1.2 Add-On Controls

In addition to power generation process technology options discussed above, it is appropriate to consider add-on technologies as possible ways to capture GHG emissions that are emitted from natural gas combustion in the proposed project's CTG units and to prevent them from entering the atmosphere. These emerging carbon capture and storage (CCS) technologies generally consist of processes that separate CO_2 from combustion process flue gas, and then inject it into geologic formations such as oil and gas reservoirs, unmineable coal seams, and underground saline formations. Of the emerging CO_2 capture technologies that have been identified, only amine absorption is currently commercially used for state-of-the-art CO_2 separation processes. Amine absorption has been applied to processes in the petroleum refining and natural gas processing industries and for exhausts from gas-fired industrial boilers. Other potential absorption and membrane technologies are currently considered developmental.

The U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) provides the following brief description of state-of-the-art post-combustion CO_2 capture technology and related implementation challenges:

> "…In the future, emerging R&D will provide numerous cost-effective technologies for capturing CO_2 from power plants. At present, however, state-of-the-art technologies for existing power plants are essentially limited to amine absorbents. Such amines are used extensively in the petroleum refining and natural gas processing industries… Amine solvents are effective at absorbing CO_2 from power plant exhaust streams—about 90 percent removal—but the highly energy-intensive process of regenerating the solvents decreases plant electricity output…"[17]

The DOE-NETL adds:

> "…Separating CO_2 from flue gas streams is challenging for several reasons:
>
> - CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems and 3-4 volume percent in gas-fired turbines) and at low pressure (15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated.
> - Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.
> - Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system…"[18]

For the combustion turbines being considered for this project, the CO_2 stack concentration at base load and ISO conditions is approximately 3.9 vol%.

If CO_2 capture can be achieved at a power plant, it would need to be routed to a geologic formation capable of long-term storage. The long-term storage potential for a formation is a function of the volumetric capacity of a geologic formation and CO_2 trapping mechanisms within

[17] DOE-NETL, *Carbon Sequestration: FAQ Information Portal*, http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cJ:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default_frontend&site=default_collection&proxystylesheet=default_frontend&oe=ISO-8859-1 (last visited Feb. 27, 2012).
[18] *Id.*

the formation, including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock. The DOE-NETL describes the geologic formations that could potentially serve as CO_2 storage sites as follows:

> "Geologic carbon dioxide (CO_2) storage involves the injection of supercritical CO_2 into deep geologic formations (injection zones) overlain by competent sealing formations and geologic traps that will prevent the CO_2 from escaping. Current research and field studies are focused on developing better understanding of 11 major types of geologic storage reservoir classes, each having their own unique opportunities and challenges. Understanding these different storage classes provides insight into how the systems influence fluids flow within these systems today, and how CO_2 in geologic storage would be anticipated to flow in the future. The different storage formation classes include: deltaic, coal/shale, fluvial, alluvial, strandplain, turbidite, eolian, lacustrine, clastic shelf, carbonate shallow shelf, and reef. Basaltic interflow zones are also being considered as potential reservoirs. These storage reservoirs contain fluids that may include natural gas, oil, or saline water; any of which may impact CO_2 storage differently…"[19]

5.1.2 Step 2: Eliminate Technically Infeasible Options

Amine absorption technology for CO_2 capture has been applied to processes in the petroleum refining and natural gas processing industries, so it may be technically feasible to apply that technology to exhausts for power plants. However, that technology has not been commercially available to power plant gas turbine exhausts, which have considerably larger flow volumes and considerably lower CO_2 concentrations. In addition, there is an added factor for the peaking units under consideration in that the temperature of the exhaust from the units under consideration is much hotter than any previous demonstration project and would require significant cooling in order to be treated using the amine process for CO2 removal. The high energy demand, high water demand, technical difficulties and economic costs associated with CCS are addressed in Step 4 of this section.

5.1.3 Step 3: Rank Remaining Control Technologies

As all of the energy efficiency related processes, practices, and designs discussed in Section 5.1.1.1 of this application are being proposed for this project, a ranking of the control technologies is not necessary for this application. As documented in Step 4 below, implementation of CCS technology is not economically reasonable, leaving energy efficiency measures as the only feasible emission control options.

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[19] DOE-NETL, *Carbon Sequestration: Geologic Storage Focus Area,* http://www.netl.doe.gov/technologies/carbon_seq/corerd/storage.html (last visited Feb. 27, 2012)

5.1.4 Step 4: Evaluate Most Effective Controls and Document Results

As all of the energy efficiency related processes, practices, and designs discussed in Section 5.1.1.1 of this application are being proposed for this project, an examination of the energy, environmental, and economic impacts of the efficiency designs is not necessary for this application.

In this section, ECEC addresses the potential energy, environmental, and economic feasibility of implementing CCS technology as BACT for GHG emissions from the proposed project's gas turbine units. Each component of CCS technology (i.e., capture and compression, transport, and storage) is discussed separately.

5.1.4.1 CO_2 Capture and Compression

Though amine absorption technology for CO_2 capture has been applied to processes in the petroleum refining and natural gas processing industries and to exhausts from gas-fired industrial boilers, it is more difficult to apply to power plant gas turbine exhausts, which have considerably larger flow volumes and considerably lower CO_2 concentrations. In addition, the temperature of the exhaust gases from the peaking units under consideration is much hotter than the exhaust that would typically be coming from a boiler or a HRSG (900°F vs. 220°F) which would require a massive heat exchanger in order to cool this exhaust to a level acceptable to the amine process. The addition of the massive heat exchangers and amine process elements needed in order to cool the exhaust, then remove, compress and transport the CO2 to the sequestration site would obviously produce a firm barrier to CCS being a viable alternative for peaking units.

The Obama Administration's Interagency Task Force on Carbon Capture and Storage confirms this in its recently completed report on the current status of development of CCS systems:

> "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 application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment."[20]

In its current CCS research program plans, the DOE-NETL confirms that commercial CO_2 capture technology for large-scale power plants is not yet available and suggests that it may not be available until at least 2020:

[20] *Report of the Interagency Task Force on Carbon Capture and Storage* at 50 (Aug. 2010).

> "The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020. To accomplish widespread deployment, four program goals have been established:
>
> (1) Develop technologies that can separate, capture, transport, and store CO_2 using either direct or indirect systems that result in a less than 10 percent increase in the cost of energy by 2015;
> (2) Develop technologies that will support industries' ability to predict CO_2 storage capacity in geologic formations to within ±30 percent by 2015;
> (3) Develop technologies to demonstrate that 99 percent of injected CO_2 remains in the injection zones by 2015;
> (4) Complete Best Practices Manuals (BPMs) for site selection, characterization, site operations, and closure practices by 2020. Only by accomplishing these goals will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades."[21A]

Typically, in discussions of potential commercially viable CO_2 sequestration, the projects mentioned are at facilities where there is a high concentration of CO_2 being emitted and have a near continuous stream of CO_2 available. The ECEC facility has neither of these criteria; thusly a peaking facility such as ECEC would be a very poor candidate for receiving any form of CCS technology.

Another challenge of CO_2 capture is conservation of water resources. A modern natural gas fired simple-cycle facility requires only minor amounts of water for turbine cleaning and for evaporative cooling. Adding CO_2 separation facilities and compression equipment significantly increases the cooling water requirements of a generating station.

5.1.4.2 CO_2 Transport

Even if it is assumed that CO_2 capture and compression could feasibly and economically be achieved for the proposed project, the CO_2 stream generated would need to be transported to a facility capable of storing it. Potential geologic storage sites in Texas, Louisiana, and Mississippi, to which CO_2 could be transported if a pipeline was constructed, are delineated on the map found at the end of Section 5.[22] The potential length of such a CO_2 transport pipeline is uncertain due to the uncertainty of identifying a site(s) that is suitable for large-scale, long-term CO_2 storage as well as the uncertainty of the exact pathway to such a site. The hypothetical minimum length required for any such pipeline(s) is the distance to the closest site with recognized potential for some geological storage of CO_2, which is the Scurry Area Canyon Reef Operators Committee (SACROC) oilfield site, located in Scurry County, Texas, approximately

[21] DOE-NETL, *Carbon Sequestration Program: Technical Program Plan,* at 10 (Feb. 2011).
[22] Susan Hovorka, University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, *New Developments: Solved and Unsolved Questions Regarding Geologic Sequestration of CO_2 as a Greenhouse Gas Reduction Method* (GCCC Digital Publication #08-13) at slide 4 (Apr. 2008), available at: http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=100(last visited Feb. 27, 2012).

150 miles (240 km) east-northeast of the project site (see the map at the end of Section 5 for the test site location). Therefore, to access this potentially large-scale storage capacity site, assuming that it is eventually demonstrated to indefinitely store a substantial portion of the large volume of CO_2 generated by the proposed project, a very long and sizable pipeline would need to be constructed to transport the large volume of high-pressure CO_2 from ECEC to the storage facility, thereby rendering implementation of a CO_2 transport system infeasible.

5.1.4.3 CO_2 Storage

Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed project and that the CO_2 could be transported economically, the feasibility of CCS technology would still depend on the availability of a suitable sequestration site. The suitability of potential storage sites is a function of volumetric capacity of their geologic formations, CO_2 trapping mechanisms within formations (including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock), and potential environmental impacts resulting from injection of CO_2 into the formations. Potential environmental impacts resulting from CO_2 injection still require assessment before CCS technology can be considered feasible include:

- Uncertainty concerning the significance of dissolution of CO_2 into brine,
- Risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water,
- Risks to fresh water as a result of leakage of CO_2, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water,[23] and
- Potential effects on wildlife.

Potentially suitable storage sites, including EOR sites and saline formations, exist in Texas, Louisiana, and Mississippi. The closest site that is being field-tested to demonstrate its capacity for geological storage of the volume of CO_2 that would be generated by the ECEC is the aforementioned SACROC oilfield site, located near Snyder, Texas, approximately 150 miles (240 km) east-northeast of the project site. It should be noted that, based on the suitability factors described above, currently the suitability of the SACROC oilfield site or any other test site to store a substantial portion of the large volume of CO_2 generated by the proposed project has yet to be fully demonstrated.

Based on the reasons provided above, ECEC believes that CCS technology should be eliminated from further consideration as a potential feasible control technology for purposes of this BACT analysis. However, to answer possible questions that the public or the EPA may have concerning the relative costs of implementing hypothetical CCS systems, ECEC has estimated such costs. Construction of a carbon capture system at ECEC would require installation of the following major pieces of equipment:

[23] *Id.*

- Two Amine Scrubber Vessels
- Two CO_2 Strippers
- Four Amine Transfer Pumps
- Four Flue Gas Fans
- Four CO_2 Gas Compressors
- One Amine Storage Tank
- Two air-cooled heat exchangers and associated auxiliary equipment

The estimated costs associated with implementation of a carbon capture system at ECEC are shown in the table below. A control cost for implementing CCS in terms of $/ton of CO_2 avoided was calculated using the "cost of electricity" methodology outlined in the U.S. Department of Energy document "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity", Revision2, November 2010, DOE/NETL-2010/1397.

It should be noted that the DOE-NETL report contained estimated costs that were based on the application of the CCS technology to a combined-cycle gas turbine. In the case of the ECEC simple-cycle gas turbines, there are no detailed cost estimations available so the DOE-NETL combined-cycle values were adjusted in order to determine the approximate values below.

	Two Simple-Cycle Combustion Turbines Without CCS	**Two Simple-Cycle Combustion Turbines With CCS**
Estimated Plant Construction Cost	$138.5 million	$425.1 million
Net Power Output (MW)	320	290
Net Plant HHV efficiency	35%	28%
Cost-of-Electricity (COE) ($/MWh) @ 28.5% capacity factor	$65.57	$172.89
CO_2 Emissions (tons/yr)	513,080	51,308
Cost of CO_2 Avoided ($/ton)	--	$529.49
Total Project Cost Increase (adding CCS)	--	306%

In addition to the high construction and operating costs associated with CCS, the carbon capture equipment requires a substantial amount of energy to operate, thereby reducing the net electrical output of the plant. Operation of carbon capture equipment at a typical natural gas fired simple-cycle plant is estimated to reduce the net energy efficiency of the plant from approximately 35% (HHV) to approximately 28% (HHV).[24]

In reality, if CCS equipment were to be installed and operated at ECEC, the cost of this equipment would drive the facility's capital and operating costs to a point where these units would not be selected for operation under the ERCOT Nodal Dispatch Model since this model

[24] US Department of Energy, National Energy Technology Laboratory, "Costs and Performance Baseline For Fossil Energy Plants, Volume 1 - Bituminous Coal and Natural Gas to Energy", Revision 2, November 2010

selects low-cost power providers for operation. The end effect of this phenomenon is that the actual capacity factor would be at or near zero, which would drive the operating costs up exponentially on a $/MWh basis. The installation of CCS equipment at ECEC would, in effect, render the project non-viable. As a result, ECEC considers the installation of CCS equipment on the simple-cycle peaking units to be not economically viable and it warrants no further consideration for BACT.

5.1.5 Step 5: Select BACT

ECEC proposes as BACT for this project, the following energy efficiency processes, practices, and designs for the proposed simple-cycle combustion turbines:

- Combustion Turbine Energy Efficiency Processes, Practices, and Designs
  - Efficient turbine design
  - Turbine inlet air cooling
  - Periodic turbine burner tuning
  - Reduction in heat loss
  - Instrumentation and controls

To determine the appropriate heat-input efficiency limit, ECEC started with the turbine's design base-load gross heat rate for simple-cycle operation and then calculated a compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions. The design base load gross heat rate for the combustion turbines being considered for this project are as follows: the General Electric 7FA.03 design base load gross heat rate is 10,470 Btu/kWh (HHV) and the 7FA.05 design base load gross heat rate is 9,849 Btu/kWh (HHV).

To determine an appropriate heat rate limit for the permit, the following compliance margins are added to the base heat rate limit:

- A 3.3% design margin reflecting the possibility that the constructed facility will not be able to achieve the design heat rate.
- A 5.0% performance margin reflecting efficiency losses due primary dispatch occurring during high-temperature months.
- A 6.0% degradation margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls.

Design and construction of a simple-cycle power plant involves many assumptions about anticipated performance of the combustion turbines, which are often imprecise or not reflective of conditions once installed at the site. As a consequence, the facility also calculates an "Installed Base Heat Rate", which represents a design margin of 3.3% to address such items as equipment underperformance.

Similarly, the demands for power vary greatly from day to day. The anticipated dispatch for these units is planned for summer months which make selecting heat rates that correspond to high-temperature ambient air conditions more likely. To address this operational limitation, ECEC applies a 5.0% performance margin to the base heat rate.

To establish an enforceable BACT condition that can be achieved over the life of the facility, the permit limit must also account for anticipated degradation of the equipment over time between regular maintenance cycles. The manufacturer's degradation curves project anticipated degradation rate of 5% within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, the projected 5% degradation rate represents the average, and not the maximum or guaranteed, rate of degradation for the gas turbines. Therefore, ECEC proposes that, for purposes of deriving an enforceable BACT limitation on the proposed facility's heat rate, gas turbine degradation may reasonably be estimated at 6% of the facility's heat rate.

As a result of these adjustments, the emission rates are as follows. ECEC proposes these limits as BACT for the project:

Turbine Model	Adjusted Heat Rate (Btu/kWh) (HHV, gross)	Output Based Emission Limit (lb CO_2/MWh, gross)
General Electric 7FA.03	12,038	1,430.76
General Electric 7FA.05	11,324	1,345.97

Note: Information provided in the heat rate column is for informational purposes only and is not intended to be enforceable.

The calculation of the gross heat rate and the gross lb/CO_2/MWhr is provided on Table 5-1 of this application. Since the plant heat rate varies according to turbine operating load, ECEC proposes to demonstrate compliance with the proposed heat rate utilizing a 12-month rolling average compliance period. This compliance period is necessary to accommodate conditions where there may be extended periods of operation at low loads. Since the turbines have a significantly lower efficiency during startup and shutdown periods, the 12-month rolling average would be applicable to normal operations only and would exclude turbine startups and shutdowns.

Startup periods would be defined as the time period beginning when the turbine receives a "turbine start" command and a flame-on signal is received by the turbine control system and would end when the combustion turbine reaches the Mode 6Q or "lean pre-mix" mode of operation. Shutdown periods are defined as the time period beginning when a "turbine stop" command has been given and the unit drops below the level where Mode 6Q or "lean pre-mix" mode of operation can be sustained and ends when the "flame-on" signal is no longer present.

On March 27, 2012, the EPA proposed New Source Performance Standard (NSPS), Subpart TTTT, which would control GHG emissions from new power plants.[25] The proposed rule would apply to fossil-fuel fired electric generating units that generate electricity for sale and are larger than 25 MW. The EPA proposed that new power plants meet an annual average output based standard of 1,000 lb CO_2/MWh gross. Although the proposed NSPS Subpart TTTT would not apply to natural gas-fired simple-cycle combustion turbines, the proposed CO_2 emission rates from the ECEC simple-cycle turbines (1,346-1,431 lb CO_2/MWh) are slightly higher than the emission limits stated in the proposed NSPS Subpart TTTT. In addition, the ECEC proposed 12-month rolling average compliance period is consistent with the proposed NSPS.

The method for calculating these emission limits will be similar to the methodology stated in the draft NSPS TTTT in that the emissions of CO_2 and the gross generator output will be summed at the end of each month for these time periods and the monthly emission rates will be calculated at that point. The twelve-month rolling average emission rate will be determined from averaging the twelve individual monthly averages for each unit.

ECEC performed a search of the EPA's RACT/BACT/LAER Clearinghouse for simple-cycle natural gas-fired combustion turbine generators and found no entries which address BACT for GHG emissions. Although not listed in the RACT/BACT/LAER Clearinghouse, several GHG BACT analyses were performed by the following natural gas fired power generation facilities: Montana Dakota Utilities R.M. Heskett Station, Pio Pico Energy Center, Black Hills Power Cheyenne Prairie Generating Station, Golden Spread Electric Coop. Antelope Station, Golden Spread Coop. Floydada Station, Guadalupe Power Partners Guadalupe Generating Station and El Paso Electric Montana Power Station.

[25] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed Reg 22392, April 13, 2012

Summary of Permitted and Proposed GHG Standards / Limits for Natural Gas-Fired Simple Cycle CTs Used for Power Generation

Company-Facility	Description	Location (State-County)	Permit No.	Permit Issue Date	GHG BACT Limits		Averaging Period(s)	Notes
					Output-Based	CO_2e Mass		
Montana-Dakota Utilities – R.M. Heskett Station	One GE 7EA unit	North Dakota-Morton	PTC13016	2/22/13	None	413,198 tpy	Mass limit: 12-mo rolling	Listed in EPA's RBLC
Pio Pico Energy Center	Three GE LMS100 units	California-San Diego	SD 11-01	11/19/12	1,328 lb CO_2/MWh (gross) 9,916 Btu/KWh (HHV)(gross)	None	720-hr rolling operating hours	- Listed in EPA's RBLC - Emission limit applies at all times outside of combustion shakedown periods - CO_2e emission limit for SF6 circuit breakers of 40.2 tpy (calendar) - Install, operate, and maintain enclosed-pressure SF6 circuit breakers with max annual leakage rate of 0.5% by wt
Black Hills Power – Cheyenne Prairie Generating Station	Three GE LM6000 PF SPRINT units	Wyoming-Laramie	PSD-WY-000001-2011.01	9/27/12	1,600 lb CO_2e/MWh (gross)	187,318 tpy (per unit)	Output-based: 365-day rolling Mass limit: 365-day rolling	- Emission limit applies at all times, including SSM periods - CO_2e and SF6 emission limits for circuit breakers of 64.5 and 0.0027 tpy (calendar), respectively
Golden Spread Electric Coop. – Antelope Station	One GE 7F 5-Series unit	Texas-Hale	N/A	N/A	1,217 lb CO_2e/MWh (gross) @ max. load 1,514 lb CO_2e/MWh (gross) @any load between 50 and 100%	538,754 tpy 237,767 lb/hr	Output-based: 30-day rolling Mass limit: 12-mo rolling	- Proposed limits as of 1/29/13 - CO_2e emission limit for SF6 circuit breakers of 174 tpy (calendar) - CO_2e emission limit for NG piping fugitive leaks of 85.55 tpy
Golden Spread Electric Coop. – Floydada Station	One GE 7F 5-Series unit	Texas-Floyd	N/A	N/A	1,217 lb CO_2e/MWh (gross) @ max. load 1,514 lb CO_2e/MWh (gross) @any load between 50 and 100%	538,754 tpy 237,767 lb/hr	Output-based: 30-day rolling Mass limit: 12-mo rolling	- Proposed limits as of January 2013 - CO_2e emission limit for SF6 circuit breakers of 174 tpy (calendar) - CO_2e emission limit for NG piping fugitive leaks of 87.4 tpy

Company-Facility	Description	Location (State-County)	Permit No.	Permit Issue Date	GHG BACT Limits		Averaging Period(s)	Notes
					Output-Based	CO_2e Mass		
Guadalupe Power Partners-Guadalupe Generating Station	Two GE 7FA.03, GE 7FA.04, GE 7FA.05, or Siemens-Westinghouse (SW) 5000F(5) units	Texas-Guadalupe	N/A	N/A	*Btu/KWh (HHV)(gross):* GE 7FA.03: 11,121 GE 7FA.04: 10,826 GE 7FA.05: 10,673 SW 5000F(5): 11,456	*tpy:* GE 7FA.03: 511,429 GE 7FA.04: 522,772 GE 7FA.05: 601,520 SW 5000F(5): 681,839	Mass limit: 12-mo rolling	- Proposed limits as of 11/12/12 - Compliance with heat rate limit to be demonstrated using annual thermal efficiency test at base load, corrected to ISO - Mass emission limits include emissions from two CTs, emergency fire water pump, fugitives from NG piping leaks, and fugitives from SF6 circuit breaker leaks
El Paso Electric – Montana Power Station	Four GE LM100 units	Texas-El Paso	N/A	N/A	1,194 lb CO_2/MWh (net)	227,840 tpy (per unit)	Output-based: 365-day rolling Mass limit: 365-day rolling	- Proposed limits as of 9/21/12 - Mass limit includes SSM emissions - Emission limit applies at all times, including SSM periods - Output-based emission limit based on CT power output and heat rate input at 50% load, 105°F

5.2 BACT FOR SF6 INSULATED ELECTRICAL EQUIPMENT

5.2.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. One technology is the use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions. In comparison to older SF_6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

One alternative considered in this analysis is to substitute another, non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NIST) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.*[26]

5.2.2 Step 2: Eliminate Technically Infeasible Options

According to the report NIST Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications.[27] It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6-insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture… it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore there are currently no technically feasible options besides use of SF_6.

5.2.3 Step 3: Rank Remaining Control Technologies

The use of state-of-the-art SF_6 technology with leak detection to limit fugitive emissions is the highest ranked control technology that is technically feasible for this application.

[26] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6,* NIST Technical Note 1425, Nov.1997.
[27] *Id.* at 28 – 29.

5.2.4 Step 4: Evaluate Most Effective Controls and Document Results

Energy, environmental, or economic impacts were not addressed in this analysis because the use of alternative, non-greenhouse-gas substance for SF_6 as the dielectric material in the breakers is not technically feasible.

5.2.5 Step 5: Select BACT

Based on this top-down analysis, ECEC concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection would be the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[28] The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to lack of "quenching and cooling" SF_6 gas.

ECEC will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use.[29] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

5.3 BACT FOR NATURAL GAS-FIRED DEW-POINT HEATER

5.3.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. The following technologies were identified as potential control options for boilers:

- Use of low carbon fuels
- Use of good operating and maintenance practices
- Energy efficient design

The fuel heater will utilize natural gas which is the lowest carbon fuel available at the ECEC site. Therefore, formation of CO_2 from combustion of the fuel will be minimized.

Good operating and maintenance practices for the fuel heater include following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing in the combustion zone; and maintain the proper air/fuel ratio so that sufficient oxygen is provided to provide complete combustion of the fuel while at the same time preventing introduction of more air than is necessary into the boiler.

[28] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.
[29] *See* 40 C.F.R. Pt. 98, Subpt. DD.

The fuel heater is designed for a thermal energy efficiency of approximately 68%. The energy efficient design of the fuel heater includes insulation to retain heat within the fuel heater and a computerized process control system that will optimize the fuel/air mixture and limit excess air in the boiler.

The fuel heater will be used to improve the efficiency of the two combustion turbines.

5.3.2 Step 2: Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable.

Use of natural gas as a low carbon fuel is technically feasible for this emission source.

Use of good operating and maintenance practices is technically feasible for this emission source.

Use of an energy efficient design for the dew-point heater is technically feasible.

5.3.3 Step 3: Rank Remaining Control Technologies

As all of the energy efficiency related processes, practices, and designs discussed in Section 5.3.1 of this application are being proposed for the fuel heater, a ranking of the control technologies is not necessary for this application.

5.3.4 Step 4: Evaluate Most Effective Controls and Document Results

As all of the energy efficiency related processes, practices, and designs discussed in Section 5.3.1 of this application are being proposed for this project, an examination of the energy, environmental, and economic impacts of the efficiency designs is not necessary for this application.

5.3.5 Step 5: Select BACT

Based on this top-down analysis, ECEC concludes that the use of natural gas as a low carbon fuel; good operating and maintenance practices and the energy efficient design are selected as BACT for the fuel heater.

5.4 BACT FOR DIESEL-FIRED EMERGENCY FIRE-WATER PUMP

The ECEC site will be equipped with one nominally rated 250-hp diesel-fired emergency fire-water pump to provide water in the event of a fire.

5.4.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. The following technologies were identified as potential control options for emergency engines:

- Use of low carbon fuel
- Use of good operating and maintenance practices
- Low annual capacity factor.

Engine options include engines powered with electricity, natural gas, or liquid fuel, such as gasoline or fuel oil.

Good operating and maintenance practices for the engines include the following:

- Operating with recommended fuel to air ratio recommended by the manufacturer and
- Appropriate maintenance of equipment, such as periodic readiness testing.

The energy efficiency (energy output divided by energy input) associated with the emergency fire pump engine is 36-38%. These are typical efficiencies for emergency engines.

Each emergency engine will be limited to 100 hours operation per year for purposes of maintenance checks and readiness testing.

5.4.2 Step 2: Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable. The purpose of the engines is to provide a power source during emergencies, which includes outages of the combustion turbines, natural gas supply outages, and natural disasters, such as floods and hurricanes. As such, the engines must be available during emergencies. Invenergy will use an electrically powered fire water pump for emergencies when electrical power is available at the facility. Utilities may not always be available during an emergency and therefore a diesel fired backup emergency engine will also be installed.

The engines must be powered by a liquid fuel that can be stored on-site in a tank and supplied to the engines on demand, such as gasoline or diesel fuels. The default CO_2 emission factors for gasoline and diesel are very similar, 70.22 kg/MMBtu for gasoline and 73.96 kg/MMBtu for diesel. Diesel fuel has a much lower volatility than gasoline and can be stored for longer periods of time. Therefore, diesel is typically the chosen fuel for emergency engines.

Because of the need to store the emergency engine fuel on-site and the ability to store diesel for longer periods of time than gasoline, it is technically infeasible to utilize a lower carbon fuel than diesel.

The use of good operating and maintenance practices is technically feasible for the emergency engines. Also, a low annual capacity factor for the engines is technically feasible since the engines will only be operated either for readiness testing or for actual emergencies.

5.4.3 Step 3: Rank Remaining Control Technologies

Since the remaining technically feasible processes, practices, and designs discussed in Section 5.4.1 of this application for the emergency engines are being proposed for the engines, a ranking of the control technologies is not necessary for this application.

5.4.4 Step 4: Evaluate Most Effective Controls and Document Results

Since the remaining technically feasible processes, practices, and designs discussed in Section 5.4.1 of this application for the emergency engines are being proposed for the engines, an evaluation of the most effective controls is not necessary for this application.

5.4.5 Step 5: Select BACT

As a result of this analysis, appropriate operation of the engines through proper fuel to air ratios and maintenance based on recommended readiness testing and low annual hours of operation are selected as BACT for the proposed engines.

5.5 BACT FOR NATURAL GAS FUGITIVES

The proposed project will include natural gas piping components. These components are potential sources of methane and CO_2 emissions due to emissions from rotary shaft seals, connection interfaces, valve stems, and similar points.

5.5.1 Step 1: Identify All Available Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. The following technologies were identified as potential control options for piping fugitives:

- Implementation of leak detection and repair (LDAR) program using a hand held analyzer
- Implementation of alternative monitoring using a remote sensing technology such as infrared cameras
- Implementation of audio/visual/olfactory (AVO) leak detection program.

5.5.2 Step 2: Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable. The use of instrument LDAR and remote sensing technologies are technically feasible. Since pipeline natural gas is odorized with a small amount of mercaptan, an AVO leak detection program for natural gas piping components is technically feasible.

5.5.3 Step 3: Rank Remaining Control Technologies

The use of a LDAR program with a portable gas analyzer meeting the requirements of 40 CFR 60, Appendix A, Method 21, can be effective for identifying leaking methane. Quarterly instrument monitoring with a leak definition of 10,000 part per million by volume (ppmv) (TCEQ 28M LDAR Program) is generally assigned a control efficiency of 75% for valves, relief valves, sampling connections, and compressors and 30% for flanges.[30] Quarterly instrument monitoring with a leak definition of 500 ppmv (TCEQ 28VHP LDAR Program) is generally assigned a control efficiency of 97% for valves, relief valves, and sampling connections, 85% for compressors, and 30% for flanges.[31] The U.S. EPA has allowed the use of an optical gas imaging instrument as an alternative work practice for a Method 21 portable analyzer for monitoring equipment for leaks in 40 CFR 60.18(g). For components containing inorganic or odorous compounds, periodic AVO walk-through inspections provide predicted control efficiencies of 97% control for valves, flanges, relief valves, and sampling connections, and 95% for compressors.[32]

5.5.4 Step 4: Evaluate Most Effective Controls and Document Results

The frequency of inspection and the low odor threshold of mercaptans in natural gas make AVO inspections an effective means of detecting leaking components in natural gas service. As discussed in Section 5.5.3, the predicted emission control efficiency is comparable to the LDAR programs using Method 21 portable analyzers.

5.5.5 Step 5: Select BACT

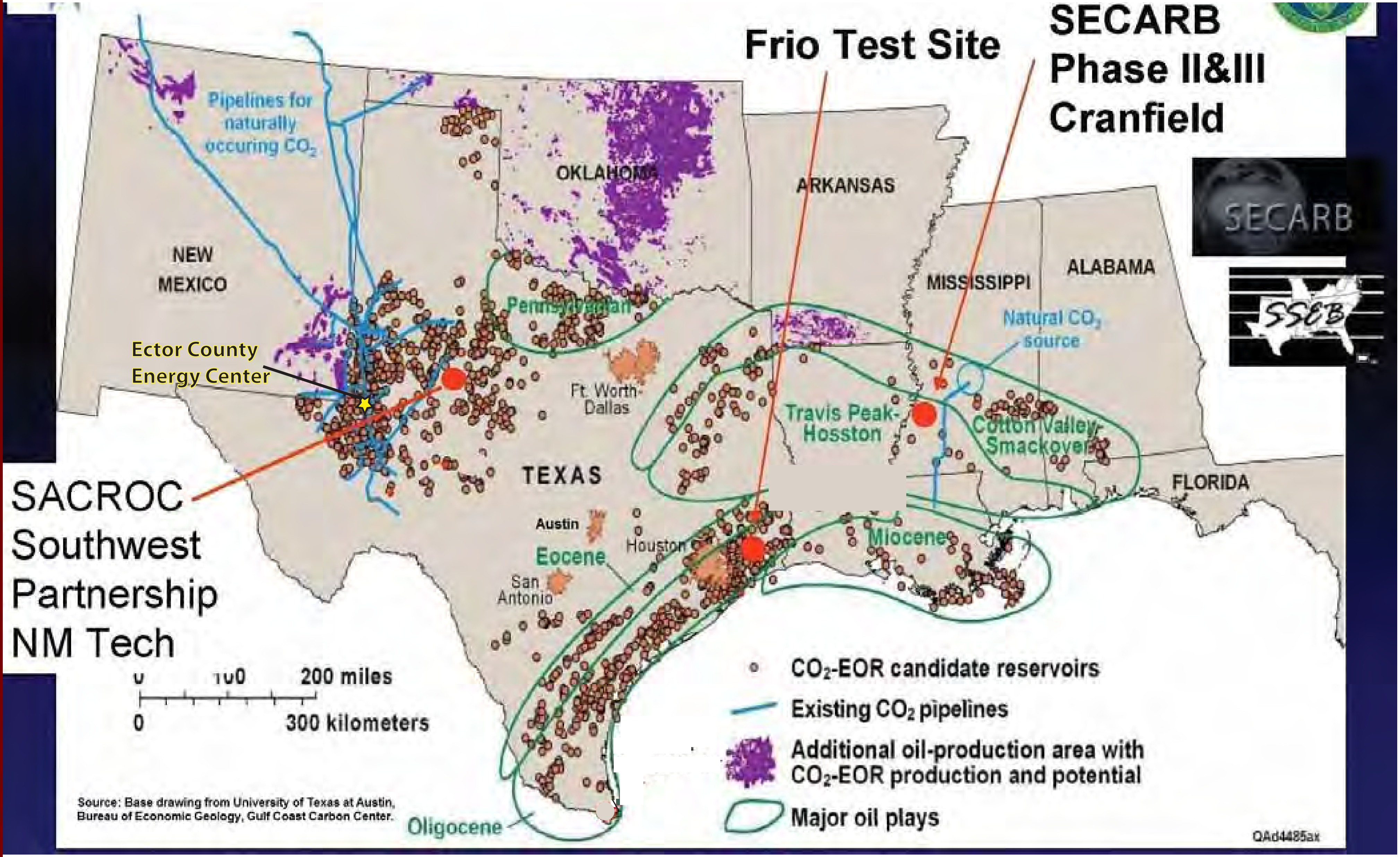
Due to the very low volatile organic compound (VOC) content of natural gas, the ECEC will not be subject to any VOC leak detection programs by way of its State/PSD air permit, TCEQ Chapter 115 – Control of Air Pollution from Volatile Organic Compounds, New Source Performance Standards (40 CFR Part 60), National Emission Standard for Hazardous Air Pollutants (40 CFR Part 61); or National Emission Standard for Hazardous Air Pollutants for Source Categories (40 CFR Part 63). Therefore, any leak detection program implemented will be solely due to potential greenhouse emissions. Since the uncontrolled CO_2e emissions from

[30] Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, TCEQ, Oct. 2000
[31] Id. at page 52.
[32] Id. at page 52.

the natural gas piping represent approximately 0.01% of the total site wide CO_2e emissions, any emission control techniques applied to the piping fugitives will provide minimal CO_2e emission reductions.

Based on this top-down analysis, ECEC concludes that a daily AVO inspection program is BACT for piping components in natural gas service. Since it is not anticipated that this facility will be manned on a routine basis, these daily AVO inspections would be performed only on days when there are operations personnel on-site on days that the combustion turbines are scheduled for operations.

MAP OF EXISTING CO_2 PIPELINES AND POTENTIAL GEOLOGIC STORAGE SITES IN TEXAS



Frio Test Site
SECARB
Phase II&III
Cranfield
SECARB
SSEB
Pipelines for naturally occuring CO_2
OKLAHOMA
ARKANSAS
NEW MEXICO
MISSISSIPPI
ALABAMA
Natural CO_2 source
Pennsylvanian
Ector County Energy Center
Ft. Worth-Dallas
Travis Peak-Hosston
Cotton Valley-Smackover
TEXAS
FLORIDA
SACROC
Southwest
Partnership
NM Tech
Austin
Houston
Miocene
Eocene
San Antonio
0 100 200 miles
0 300 kilometers
CO_2-EOR candidate reservoirs
Existing CO_2 pipelines
Additional oil-production area with CO_2-EOR production and potential
Major oil plays
Source: Base drawing from University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center.
Oligocene
QAd4485ax

TABLE 5-1 CALCULATION OF DESIGN HEAT RATES FOR GE 7FA.03 AND 7FA.05

Table 5-1
GHG Emission Calculations - Calculation of Design Heat Rate and Output Limits for Simple Cycle Combustion Turbines
Ector County Energy Center

	7FA.03 Gross Basis	7FA.05 Gross Basis	
Base Heat Rate:	**10,470**	**9,849**	Btu/kWh (HHV)
Design Margin:	3.3%	3.3%	
Performance Margin:	5.0%	5.0%	
Degradation Margin:	6.0%	6.0%	
Adjusted Base Heat Rate with Compliance Margins:	**12,038**	**11,324**	Btu/kWh (HHV)

EPN	Adjusted Heat Rate (Btu/kWhr)	Electrical Output Basis	Heat Input Required to Produce 1 MW (MMBtu/MWhr)	Pollutant	Emission Factor (lb/MMBtu)[1]	lb GHG/MWhr[2] (gross basis)	Global Warming Potential[3]	lb CO_{2e}/MWhr[4] (gross basis)
CT-1 7FA.03 Variant	12,038	Gross	12.04	CO_2	118.86	1,430.76	1	1,430.76
				CH_4	2.2E-03	2.65E-02	21	5.57E-01
				N_2O	2.2E-04	2.65E-03	310	8.23E-01
					Total:	**1,430.8**		**1,432.1**
CT-1 7FA.05 Variant	11,324	Gross	11.32	CO_2	118.86	1,345.97	1	1,345.97
				CH_4	2.2E-03	2.50E-02	21	5.24E-01
				N_2O	2.2E-04	2.50E-03	310	7.74E-01
					Total:	**1,346.0**		**1,347.3**

Note

1. CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.
2. *CO_2 emissions based on 40 CFR Part 75, Appendix G, Equation G-4*

$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2000$

W_{CO2} = CO_2 emitted from combustion, tons/yr

F_c = Carbon based F-factor,1040 scf/MMBtu

H = Heat Input (MMBtu/yr)

U_f = 1/385 scf CO_2/lbmole at 14.7 psia and 68 ^oF

MW_{CO2} = Molecule weight of CO_2, 44.0 lb/lbmole

3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
4. *Example calculation: GHG emissions (lbs) x Global Warming Potential / 1 MW = lb CO_2e/MWhr*

6.0 OTHER PSD REQUIREMENTS

6.1 IMPACTS ANALYSIS

An impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause contribute to a violation of the NAAQS are not applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO_2 or GHGs.*[33]

An impacts analysis for non-GHG emissions is being submitted with the State/PSD/NSR application submitted to the TCEQ.

6.2 GHG PRECONSTRUCTION MONITORING

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations:

> *EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.*[34]

A pre-construction monitoring analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment application submitted to the TCEQ.

6.3 ADDITIONAL IMPACTS ANALYSIS

A PSD additional impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions*

[33] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* at 47-49.
[34] *Id.* at 48.

> *contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.*[35]

A PSD additional impacts analysis for non-GHG emissions is being submitted with the State/PSD/NSR application submitted to the TCEQ.

[35] *Id.* at 48.

7.0 PROPOSED GHG MONITORING PROVISIONS

ECEC proposes to monitor CO_2 emissions by monitoring the quantity of fuel combusted in the turbines and performing periodic fuel sampling as specified in 40 CFR 75.10(3)(ii) (refer to procedure below). Results of the fuel sampling and analyses will be used to calculate a site-specific Fc factor and that factor will be used in the equation below to calculate CO_2 mass emissions.

The ECEC natural gas-fired turbines will comply with the fuel flow metering and Gross Calorific Value (GCV) sampling requirements of 40 CFR Part 75, Appendix D. The site-specific Fc factor will be determined using the ultimate analysis and Gross Calorific Value in equation F-7b of 40 CFR 75, Appendix F. The site-specific Fc factor will be determined in accordance with 40 CFR 75, Appendix F, §3.3.6.

The procedure for estimating CO_2 Emissions specified in 40 CFR 75.10(3)(ii) is as follows:

Affected gas-fired and oil-fired units may use the following equation:

$$W_{CO2} = (F_c \times H \times U_f \times MW_{CO2})/2{,}000$$

Where:

W_{CO2} = CO_2 *emitted from combustion, tons/hr*

MW_{CO2} = *molecular weight of* CO_2*, 44.0 lb/lbmole*

F_c = *Carbon based F-factor, (1,040 scf/MMBtu for natural gas <u>or a site-specific F_c factor</u>)*

H = Hourly heat input in MMBtu, as calculated using the procedure in 40 CFR 75, Appendix F, §5)

U_f = *1/385 scf* CO_2*/lb-mole at 14.7 psia and 68 °F*

The requirements for fuel flow monitoring and quality assurance in 40 CFR 75 Appendix D are as follows:

Fuel flow meter: meet an accuracy of 2.0 %, required to be tested once each calendar quarter (40 CFR 75, Appendix D, §2.1.5 and §2.1.6(a))
Gross Calorific Value (GCV): determine the GCV of pipeline natural gas at least once per calendar month (40 CFR 75, Appendix D, §2.3.4.1)

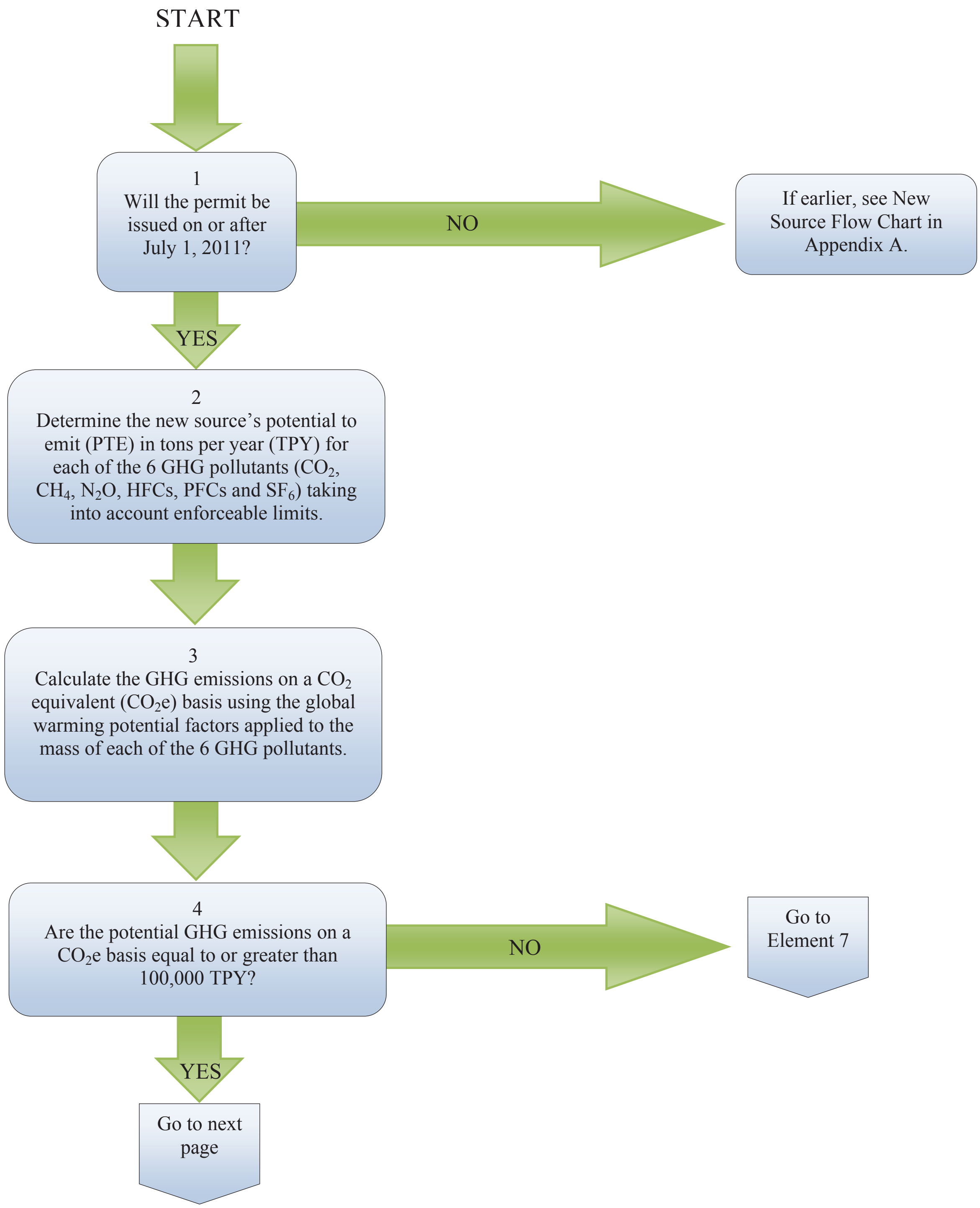
This monitoring approach is consistent with the CO_2 reporting requirements of the GHG Mandatory Reporting Rule for Electricity Generation (40 CFR 98, Subpart D). Subpart D requires electric generating sources that report CO_2 emissions under 40 CFR 75 to report CO_2 under 40 CFR 98 by converting CO_2 tons reported under Part 75 to metric tons.

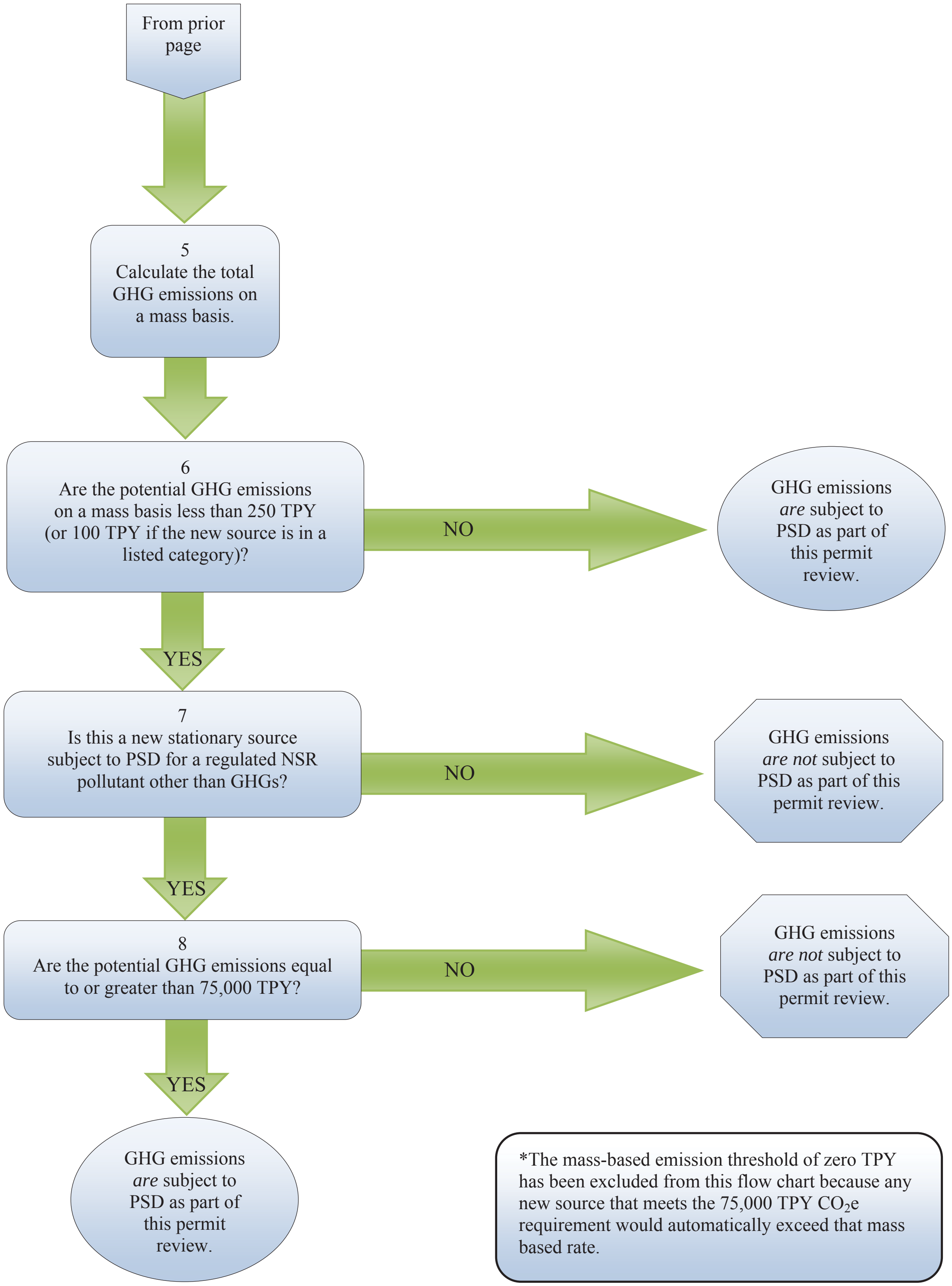
In addition, the recently proposed NSPS Subpart TTTT –Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units (40 CFR §60.5535(c)) would allow electric generating units firing gaseous fuel and liquid fuel oil to determine CO_2 mass emissions by monitoring fuel combusted in the affected Electric Generating Unit and using a site specific Fc factor determined in accordance with 40 CFR 75, Appendix F. Therefore, ECEC's proposed CO_2 monitoring method would be consistent with the proposed NSPS Subpart TTTT.

APPENDIX A

GHG PSD APPLICABILITY FLOWCHART – MODIFIED SOURCES

Appendix B. GHG Applicability Flow Chart – New Sources (On or after July 1, 2011)




From prior page
5
Calculate the total GHG emissions on a mass basis.
6
Are the potential GHG emissions on a mass basis less than 250 TPY (or 100 TPY if the new source is in a listed category)?
NO
GHG emissions *are* subject to PSD as part of this permit review.
YES
7
Is this a new stationary source subject to PSD for a regulated NSR pollutant other than GHGs?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
8
Are the potential GHG emissions equal to or greater than 75,000 TPY?
NO
GHG emissions *are not* subject to PSD as part of this permit review.
YES
GHG emissions *are* subject to PSD as part of this permit review.
*The mass-based emission threshold of zero TPY has been excluded from this flow chart because any new source that meets the 75,000 TPY CO_2e requirement would automatically exceed that mass based rate.