TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

EXAMPLE A

NOTICE OF APPLICATION AND PRELIMINARY DECISION FOR AN AIR QUALITY PERMIT

PROPOSED AIR QUALITY PERMIT NUMBERS: 110423 AND PSDTX1366

APPLICATION AND PRELIMINARY DECISION. Invenergy Thermal Development LLC, 1 South Wacker Drive, Suite 1900 , Chicago, IL 60606-4644, has applied to the Texas Commission on Environmental Quality (TCEQ) for issuance of Proposed Air Quality Permit 110423 and Prevention of Significant Deterioration (PSD) Air Quality Permit PSDTX1366, which would authorize construction of the Ector County Energy Center. The facility location is as follows: from Goldsmith, drive east on Highway 158 and turn north on Holt Road. Turn west on SW 3601, drive 3 miles and the facility is on the right, Goldsmith, Ector County, Texas 79741. This application was submitted to the TCEQ on May 13, 2013. The proposed facility will emit the following air contaminants in a significant amount: nitrogen oxides, carbon monoxide, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, sulfur dioxide, and sulfuric acid. In addition, the facility will emit the following air contaminants: organic compounds and hazardous air pollutants.

The degree of PSD increment predicted to be consumed by the proposed facility and other increment-consuming sources in the area is as follows:

PM_{10}

Maximum Averaging Time	Maximum Increment Consumed (µg/m³)	Allowable Increment (µg/m³)
24-hour	5.8	30
Annual	1.1	17

Nitrogen Dioxide

Maximum Averaging Time	Maximum Increment Consumed (µg/m³)	Allowable Increment (µg/m³)
Annual	3.5	25

$PM_{2.5}$

Maximum Averaging Time	Maximum Increment Consumed (µg/m³)	Allowable Increment (µg/m³)
24-hour	5.6	9
Annual	1.5	4

The executive director has determined that the emissions of air contaminants from the proposed facility which are subject to PSD review will not violate any state or federal air quality regulations and will not have any significant adverse impact on soils, vegetation, or visibility. All air contaminants have been evaluated, and "best available control technology" will be used for the control of these contaminants.

The executive director has completed the technical review of the application and prepared a draft permit which, if approved, would establish the conditions under which the facility must operate. The permit application, executive director's preliminary decision, draft permit, and the executive director's preliminary determination summary and executive director's air quality analysis, will be available for viewing and copying at the TCEQ central office, the TCEQ Midland regional office, and the Ector County Library, 321 West 5th Street, Odessa, Ector County, Texas, beginning the first day of publication of this notice. The facility's compliance file, if any exists, is available for public review at the TCEQ Midland Regional Office, 9900 West Interstate 20 Suite 100, Midland, Texas.

INFORMATION AVAILABLE ONLINE. These documents are accessible through the Commission's Web site at www.tceq.texas.gov/goto/cid: the executive director's preliminary decision which includes the draft permit, the executive director's preliminary determination summary, the air quality analysis, and, once available, the executive director's response to comments and the final decision on this application. Access the Commissioners' Integrated Database (CID) using the above link and enter the permit number for this application. The public location mentioned above, the Ector County Library, provides public access to the internet. This link to an electronic map of the site or facility's general location is provided as a public courtesy and not part of the application or notice. For exact location, refer to application. http://www.tceq.texas.gov/assets/public/hb610/index.html?lat=32.069444&lng=-102.585555&zoom=13&type=r.

PUBLIC COMMENT/PUBLIC MEETING. You may submit public comments or request a public meeting about this application. The purpose of a public meeting is to provide the opportunity to submit comment or to ask questions about the application. The TCEQ will hold a public meeting if the executive director determines that there is a significant degree of public interest in the application, if requested by an interested person, or if requested by a local legislator. A public meeting is not a contested case hearing. **You may submit additional written public comments within 30 days of the date of newspaper publication of this notice in the manner set forth in the AGENCY CONTACTS AND INFORMATION paragraph below.**

After the deadline for public comment, the executive director will consider the comments and prepare a response to all public comment. **The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application.**

OPPORTUNITY FOR A CONTESTED CASE HEARING. A contested case hearing is a legal proceeding similar to a civil trial in a state district court. **A person who may be affected by emissions of air contaminants from the facility is entitled to request a hearing. A contested case hearing request must include the following: (1) your name (or for a group or association, an official representative), mailing address, daytime phone number, and fax number, if any; (2) applicant's name and permit number; (3) the statement "I/we request a contested case hearing;" (4) a specific description of how you would be adversely affected by the application and air emissions from the facility in a way not common to the general public; (5) the location and distance of your property relative to the facility; and (6) a description of how you use the property which may be impacted by the facility. If the request is made by a group or association, then one or more members who have standing to request a hearing and the interests the group or association seeks to protect must also be identified. You may also submit your proposed adjustments to the application/permit which would satisfy your concerns. Requests for a contested case hearing must be submitted in writing within 30 days following**

this notice to the Office of the Chief Clerk, at the address provided in the information section below.

A contested case hearing will only be granted based on disputed issues of fact that are relevant and material to the Commission's decisions on the application. Further, the Commission will only grant a hearing on issues raised by you or others during the public comment period that have not been withdrawn. Issues that are not raised in public comments may not be considered during a hearing.

EXECUTIVE DIRECTOR ACTION. If a timely contested case hearing request is not received or if all timely contested case hearing requests are withdrawn, the executive director may issue final approval of the application. The response to comments, along with the executive director's decision on the application will be mailed to everyone who submitted public comments or is on a mailing list for this application, and will be posted electronically to the CID. If any timely hearing requests are received and not withdrawn, the executive director will not issue final approval of the permit and will forward the application and requests to the Commissioners for their consideration at a scheduled commission meeting.

MAILING LIST. You may ask to be placed on a mailing list to obtain additional information on this application by sending a request to the Office of the Chief Clerk at the address below.

AGENCY CONTACTS AND INFORMATION. Public comments and requests must be submitted either electronically at www.tceq.texas.gov/about/comments.html, or in writing to the Texas Commission on Environmental Quality, Office of the Chief Clerk, MC-105, P.O. Box 13087, Austin, Texas 78711-3087. If you communicate with the TCEQ electronically, please be aware that your email address, like your physical mailing address, will become part of the agency's public record. For more information about this permit application or the permitting process, please call the Public Education Program toll free at 1-800-687-4040. Si desea información en Español, puede llamar al 1-800-687-4040.

Further information may also be obtained from Invenergy Thermal Development LLC at the address stated above or by calling Mr. Matthew Thornton, Business Development Manager at (312) 582-1527.

Notice Issuance Date: May 30, 2014

Emission Sources - Maximum Allowable Emission Rates

Permit Numbers 110423 and PSDTX1366

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
CT-1 (Option 1)	Unit 1 (GE 7FA.03) (Option 1) Normal Operation	NO_x	62.34	-
		CO	37.95	-
		VOC	13.28	-
		SO_2	27.40	-
		PM	25.15	-
		PM_{10}	25.15	-
		$PM_{2.5}$	25.15	-
		H_2SO_4	12.59	-
CT-1 (Option 1)	Unit 1 (GE 7FA.03) (Option 1) MSS Operation	NO_x	66.50	-
		CO	477.60	-
		VOC	36.00	-
		SO_2	27.40	-
		PM	25.15	-
		PM_{10}	25.15	-
		$PM_{2.5}$	25.15	-
		H_2SO_4	12.59	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
CT-1 (Option 1)	Unit 1 (GE 7FA.03) (Option 1) All Operation (Normal+MSS)	NO_x	-	52.68
		CO	-	132.27
		VOC	-	16.24
		SO_2	-	20.57
		PM	-	22.98
		PM_{10}	-	22.98
		$PM_{2.5}$	-	22.98
		H_2SO_4	-	9.45
CT-2 (Option 1)	Unit 2 (GE 7FA.03) (Option 1) Normal Operation	NO_x	62.34	-
		CO	37.95	-
		VOC	13.28	-
		SO_2	27.40	-
		PM	25.15	-
		PM_{10}	25.15	-
		$PM_{2.5}$	25.15	-
		H_2SO_4	12.59	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
CT-2 (Option 1)	Unit 2 (GE 7FA.03) (Option 1) MSS Operation	NO_x	66.50	-
		CO	477.60	-
		VOC	36.00	-
		SO_2	27.40	-
		PM	25.15	-
		PM_{10}	25.15	-
		$PM_{2.5}$	25.15	-
		H_2SO_4	12.59	-
CT-2 (Option 1)	Unit 2 (GE 7FA.03) (Option 1) All Operation (Normal+MSS)	NO_x	-	52.68
		CO	-	132.27
		VOC	-	16.24
		SO_2	-	20.57
		PM	-	22.98
		PM_{10}	-	22.98
		$PM_{2.5}$	-	22.98
		H_2SO_4	-	9.45

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
CT-1 (Option 2)	Unit 1 (GE 7FA.05) (Option 2) Normal Operation	NO_x	63.62	-
		CO	38.73	-
		VOC	3.00	-
		SO_2	28.33	-
		PM	26.83	-
		PM_{10}	26.83	-
		$PM_{2.5}$	26.83	-
		H_2SO_4	13.02	-
CT-1 (Option 2)	Unit 1 (GE 7FA.05) (Option 2) MSS Operation	NO_x	66.50	-
		CO	477.60	-
		VOC	36.00	-
		SO_2	28.33	-
		PM	26.83	-
		PM_{10}	26.83	-
		$PM_{2.5}$	26.83	-
		H_2SO_4	13.02	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
CT-1 (Option 2)	Unit 1 (GE 7FA.05) (Option 2) All Operation (Normal+MSS)	NO_x	-	78.82
		CO	-	148.18
		VOC	-	11.25
		SO_2	-	35.42
		PM	-	33.54
		PM_{10}	-	33.54
		$PM_{2.5}$	-	33.54
		H_2SO_4	-	16.27
CT-2 (Option 2)	Unit 2 (GE 7FA.05) (Option 2) Normal Operation	NO_x	63.62	-
		CO	38.73	-
		VOC	3.00	-
		SO_2	28.33	-
		PM	26.83	-
		PM_{10}	26.83	-
		$PM_{2.5}$	26.83	-
		H_2SO_4	13.02	-

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
CT-2 (Option 2)	Unit 2 (GE 7FA.05) (Option 2) MSS Operation	NO_x	66.50	-
		CO	477.60	-
		VOC	36.00	-
		SO_2	28.33	-
		PM	26.83	-
		PM_{10}	26.83	-
		$PM_{2.5}$	26.83	-
		H_2SO_4	13.02	-
CT-2 (Option 2)	Unit 2 (GE 7FA.05) (Option 2) All Operation (Normal+MSS)	NO_x	-	78.82
		CO	-	148.18
		VOC	-	11.25
		SO_2	-	35.42
		PM	-	33.54
		PM_{10}	-	33.54
		$PM_{2.5}$	-	33.54
		H_2SO_4	-	16.27
CTLV1	Combustion Turbine 1 Lube Oil Vent	VOC	0.09	0.40
		PM	0.09	0.40
		PM_{10}	0.09	0.40
		$PM_{2.5}$	0.09	0.40

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
CTLV2	Combustion Turbine 2 Lube Oil Vent	VOC	0.09	0.40
		PM	0.09	0.40
		PM_{10}	0.09	0.40
		$PM_{2.5}$	0.09	0.40
NGFUG	Natural Gas Fugitives	VOC	0.01	0.02
FWP (5)	250 Hp Diesel-fired, Fire Water Pump	NO_x	1.36	0.07
		CO	0.66	0.03
		VOC	0.03	<0.01
		SO_2	0.03	<0.01
		PM	0.06	<0.01
		PM_{10}	0.06	<0.01
		$PM_{2.5}$	0.06	<0.01
MSS FUG	MSS Fugitives	NO_x	<0.01	<0.01
		CO	<0.01	<0.01
		VOC	0.07	<0.01
		PM	0.09	0.02
		PM_{10}	0.09	0.02
		$PM_{2.5}$	0.09	0.02

Emission Sources - Maximum Allowable Emission Rates

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
CO - carbon monoxide
H_2SO_4 sulfuric acid
(4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.
(5) The allowable emission rates include planned maintenance, startup, and shutdown activities.

Date: ______________________

Special Conditions

Permit Numbers 110423 and PSDTX1366

Emission Rates and Permit Representations

1. This permit covers only those sources of emissions listed in the attached table entitled “Emission Sources - Maximum Allowable Emission Rates,” and those sources are limited to the emission limits and other conditions specified in that attached table. This permit authorizes planned maintenance, startup, and shutdown (MSS) activities which comply with the emission limits in the maximum allowable emission rates table (MAERT).

2. Emission limits are based upon representations in the permit application dated May 13, 2013, as subsequently updated.

3. The following sources are authorized under Title 30 Texas Administrative Code Chapter 106 (30 TAC Chapter 106):

Permit By Rule (PBR)	PBR No.
Boilers, Heaters, and Other Combustion Devices	§106.183
Organic and Inorganic Liquid Loading and Unloading.	§106.472

Federal Applicability

4. The sources identified in this condition are subject to and shall comply with applicable requirements of Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):

Source	Emission Point Number (EPN)	Subpart	Standards of Performance for:
Combustion Turbines (CTs)	CT-1 CT-2	KKKK	Stationary Gas Turbines
Fire Water Pump Engine	FWP	IIII	Stationary Compression-Ignition Internal Combustion Engines
All of the above sources		A	General Conditions

5. The sources identified in this condition are subject to and shall comply with applicable requirements of 40 CFR Part 63 follows:

Source	EPN	Subpart	Standards of Performance for:
Fire Water Pump Engine	FWP	ZZZZ	Stationary Reciprocating Internal Combustion Engines
All of the above sources		A	General Conditions

Operating Limitations, Performance Standards, and Fuel Specifications

6. This permit authorizes two natural gas-fired CTs (identified as Unit 1 and Unit 2) to operate in simple cycle, and one emergency fire water pump engine (EPN FWP). Each CT shaft drives an electric generator. The CTs may employ evaporative cooling for power enhancement.

   A. This permit authorizes construction and operation of one of the following two CT models: General Electric (GE) 7FA.03 or GE 7FA.05.

      Within sixty days after selection of the CT model, the permit holder must notify the Texas Commission on Environmental Quality (TCEQ) of the selected CT model, submitted with an alteration request to revise this permit to delete language applicable to the non-selected CT model.

   B. The CTs are authorized to operate in normal operation, defined as operation that is not MSS operation.

   C. The 250-horsepower (hp) emergency fire water pump engine is limited to 100 hours of non-emergency operation per year, on a rolling 12-month basis.

   D. Each CT (EPNs CT-1 and CT-2) is limited to no more than 2,500 hours of operation per rolling 12-month period.

7. Fuel Specifications

   A. Fuel for the CTs shall be limited to firing pipeline-quality, sweet natural gas containing no more than 1.0 grain total sulfur per 100 dry standard cubic feet (dscf).

   B. The permit holder shall install, calibrate, maintain, and operate a continuous monitoring system to monitor and record the average hourly natural gas consum ption of each CT. The permit holder shall comply with the applicable initial certification and ongoing quality assurance requirements of 40 CFR Part 75, Appendix D for each CT.

   C. The emergency fire water pump engine must use diesel fuel containing no more than 0.0015 percent (%) sulfur by weight.

   D. Upon request by the Executive Director of the TCEQ or any air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel fired in the CTs and the fire water pump engine, or shall allow air pollution control agency representatives to obtain a sample for analysis.

8. While operating in normal operation, emissions from Unit 1 and Unit 2 shall not exceed the following concentrations in parts per million by volume, dry basis (ppmvd) at 15% oxygen (O_2). Compliance with the nitrogen oxides (NO_x) and carbon monoxide (CO) concentration limits shall be demonstrated on a three-hour rolling average using the continuous emissions monitoring systems (CEMS) required by Special Condition No. 16.

Pollutant	Concentration (ppmvd)
NO_x	9.0
CO	9.0

9. Except during MSS activities, the opacity of emissions from the CT 1 and CT-2 shall not exceed five % averaged over a six-minute period from each stack or vent. During MSS activities, the opacity shall not exceed 15%. Each determination shall be made by first observing for visible emissions while each facility is in operation. Observations shall be made at least 15 feet and no more than 0.25 miles from the emission point. If visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using 40 CFR Part 60, Appendix A, Test Method 9. Contributions from uncombined water shall not be included in determining compliance with this condition.

Observations shall be performed and recorded quarterly. If the opacity exceeds five percent during normal operations or 15% during MSS activities, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation.

Maintenance, Startup and Shutdown

10. Attachment A identifies the inherently low emitting (ILE) planned maintenance activities that this permit authorizes to be performed. Attachment B identifies the planned maintenance activities that are non-ILE planned maintenance activities that this permit authorizes to be performed.

11. The holder of this permit shall minimize emissions during planned MSS activities by operating the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility.

12. Emissions during planned MSS activities will be minimized by limiting the duration of operation in planned MSS modes as follows:

    A. A planned startup event is defined as the period beginning when the gas turbine receives a "turbine start" signal and an initial flame detection signal is recorded in the plant's control system and ending when the combustion turbine output reaches the lean pre-mix operating mode. A planned startup for each CT is limited to 60 minutes.

    B. A shutdown event is defined as the period beginning when the gas turbine receives a "turbine stop" command and the generator output drops below the minimum stable load and ending when a flame detection signal is no longer recorded in the plant's control system. A planned shutdown for each CT is limited to 60 minutes.

    C. Emissions from CT optimization activities, as defined in Attachment B, shall be subject to the hourly emission limits for MSS activities from CTs listed on the MAERT. The emissions from such activities shall not exceed the hourly emission limits for normal operation for more than eight hours per calendar day.

13. Compliance with the emissions limits for planned MSS activities identified in the MAERT attached to this permit shall be demonstrated as follows.

    A. For ILE planned maintenance activities identified in Attachment A of this permit:

(1) The total emissions from all ILE planned maintenance activities shall be considered to be no more than the estimated potential to emit for those activities that are represented in the permit application.

(2) The permit holder shall annually confirm the continued validity of the estimated potential to emit represented in the permit application for all ILE planned maintenance activities.

B. For CT planned non-ILE maintenance activities identified in Attachment B of this permit, the permit holder shall do the following.

(1) For each pollutant whose emissions are measured with a CEMS that has been certified to measure the pollutant's emissions over the entire range of a planned MSS activity, the permit holder shall measure the emissions of the pollutant during the planned MSS activity using the CEMS.

(2) For each pollutant whose emissions are not measured with a CEMS in accordance with B(1) of this condition, determine for each calendar month the emissions of each pollutant listed on the MAERT of this permit from all occurrences of planned MSS activity by calculation. The calculations of the pollutant's hourly and monthly emissions must use data related to the planned MSS activity, identified in turbine operating records, work orders, or equivalent records. The emission rate of the pollutant during the planned MSS activity must be determined either:

(a) as represented in the permit application; or

(b) as determined with an appropriate method, including but not limited to any of the following methods, provided that the permit holder maintains appropriate records supporting such determination:

i. use of emission factor(s), facility-specific parameter(s), and/or engineering knowledge of the facility's operations;

ii. use of emissions data measured (by a CEMS or during emissions testing) during the same type of planned MSS activity occurring at or on a similar facility, and correlation of that data with the activity's or facility's relevant operating parameters;

iii. use of emissions testing data collected during a planned MSS activity occurring at or on the facility, and correlation of that data with the facility's or activity's relevant operating parameters, such as electric load, temperature, fuel input, or fuel sulfur content; or

iv. use of parametric monitoring system data applicable to the facility.

Initial Determination of Compliance

14. Sampling ports and platforms shall be incorporated into the design of the exhaust stacks identified as EPNs CT-1 and CT-2, according to the specifications set forth in the attachment entitled "Chapter 2, Stack Sampling Facilities." Alternate sampling facility designs may be submitted for approval by the TCEQ Regional Director.

15. The holder of this permit shall perform stack sampling and other testing to establish the actual quantities of air contaminants being emitted into the atmosphere from EPNs CT-1 and CT-2. Unless otherwise specified in this special condition, the sampling and testing shall be conducted in accordance with the methods and procedures specified in Special Condition No. 15F. The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

    A. Air contaminants and diluents from the CTs to be sampled and analyzed include (but are not limited to) NO_x, CO, volatile organic compounds (VOC), sulfur dioxide (SO_2), opacity, O_2, and particulate matter (PM) (filterable plus condensable fractions).

    B. The CTs shall be tested at the maximum load for the atmospheric conditions which exist during testing. CT generator load shall be identified in the sampling report.

    C. Fuel sampling using the methods and procedures of 40 CFR § 60.4415 may be conducted in lieu of stack sampling for SO_2. If fuel sampling is used, then compliance with the 40 CFR Part 60, Subpart KKKK, SO_2 limits shall be based on 100% conversion of the sulfur in the fuel to SO_2.

    D. Requests to waive testing for any air contaminant specified in this condition shall be submitted to the TCEQ Air Permits Division. Test waivers and alternate or equivalent procedure proposals for testing which must have EPA approval shall be submitted to the TCEQ Air Permits Division.

E. Sampling as required by this condition shall occur within 60 days after achieving the maximum production but no later than 180 days after initial startup of each unit. Additional sampling shall occur as may be required by the TCEQ or EPA.

F. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ "Sampling Procedures Manual" and EPA Test Methods in 40 CFR Part 60, Appendix A.

G. The TCEQ Midland Regional Office shall be given notice as soon as testing is scheduled but not less than 30 days prior to sampling to schedule a pretest meeting.

(1) The notice shall include:

(a) Date for pretest meeting.

(b) Date sampling will occur.

(c) Name of firm conducting sampling.

(d) Type of sampling equipment to be used.

(e) Methods and procedures to be used in sampling, including methods to demonstrate compliance with emission standards found in 40 CFR Part 60, Subpart KKKK.

(f) Procedure used to determine turbine loads during the sampling period.

(2) The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports.

(3) Prior to the pretest meeting, a written proposed description of any deviation from sampling procedures specified in permit conditions or TCEQ or EPA sampling procedures shall be made available to the TCEQ. The TCEQ Regional Director shall approve or disapprove of any deviation from specified sampling procedures.

H. Copies of the final sampling report shall be distributed to the TCEQ and EPA within 60 days after sampling is completed. Sampling report format shall comply with Chapter 14 of the TCEQ "Sampling Procedures Manual." The reports shall be distributed as follows:

One copy to the EPA Region 6 Office, Dallas.
One copy to the TCEQ Midland Regional Office.
One copy to the TCEQ Air Permits Division in Austin.

Continuous Determination of Compliance

16. The permit holder shall install, calibrate, and maintain a CEMS to measure and record the in-stack concentration of NO_x, CO, and O_2 from each CT stack, EPNs CT-1 and CT-2.

A. The NO_x and O_2 CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 2 and 3, 40 CFR Part 60, Appendix B. The permit holder shall assure that the CEMS meets the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, 5.2.3 and any CEMS downtime shall be reported to the TCEQ Midland Regional Director, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the TCEQ Midland Regional Director. Compliance with the CEMS requirements of 40 CFR Part 60 can be demonstrated by meeting the applicable requirements of 40 CFR Part 75 provided that the holder of this permit demonstrates compliance with all applicable 40 CFR Part 60 emission standards.

B. The CO CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable performance specifications in 40 CFR Part 60, Performance Specification No. 4. The CEMS shall meet the applicable quality assurance requirements specified in 40 CFR Part 60, Appendix F, except that cylinder gas audits (CGA) conducted in all four quarters may be used in lieu of the annual relative accuracy test audit (RATA). Quarterly CGAs shall be conducted at least 60 days apart. A CGA is not required in any quarter in which the CT operates less than 168 hours.

C. Relative accuracy exceedances (as specified in 40 CFR Part 60, Appendix F), CGA exceedances of ±15% accuracy, and any CEMS downtime shall be reported to the TCEQ Midland Regional Director, and necessary corrective action shall be taken. Supplemental stack sampling may be required at the discretion of the TCEQ Midland Regional Director.

D. If any emission monitor fails to meet specified performance, it shall be repaired or replaced immediately. If repair or replacement is not immediately feasible, the monitor shall be repaired or replaced no later than seven days after the failure is first detected by an employee at the site, unless written permission is obtained from the TCEQ which allows for longer repair/replacement time. The holder of this permit shall develop an operation and maintenance program (including stocking necessary spare parts) to ensure that the continuous monitors are available as required. A monitor with downtime due to breakdown or repair of more than 10% of the facility operating time for any calendar year will be considered as a defective monitor and the monitor must be replaced within two weeks after exceeding the 10% threshold.

E. The monitoring data shall be reduced to hourly average concentrations at least once every day, using a minimum of four equally-spaced data points from each one-hour period. The individual average concentrations shall be reduced to units of lbs/hr at least once every day.

F. The monitoring data and quality-assurance data shall be maintained by the source. The data from the CEMS will be used to determine compliance with the conditions of this permit. During periods where the CEMS data is unavailable or not quality assured, compliance may alternatively be determined by using manufacturer emission factors or valid and representative data previously measured and recorded by the unit's CEMS under similar operating conditions.

G. The TCEQ Regional Office in Midland shall be notified at least 30 days prior to any RATA in order to provide them the opportunity to observe the testing.

17. The permit holder shall monitor fuel consumption from Unit 1 and Unit 2 individually and continuously, using monitoring devices that are accurate to ±2.0% of the unit's maximum flow and maintain, calibrate, and operate the devices in accordance with the manufacturer's specifications. The devices shall be calibrated in accordance with the manufacturer's recommendations or at least annually.

18. After the initial demonstration of compliance, ongoing compliance with the VOC and PM (including PM_{10} and $PM_{2.5}$) tons per year emission rates in the MAERT shall be demonstrated by calculating rolling 12-month annual emissions

from emission factors (pounds per million British thermal units (lb/MMBtu), higher heating value (HHV)) obtained from the results of the sampling required by Special Condition No. 15 and the monthly total heat input (MMBtu, HHV) from natural gas fuel.

19. If any emission monitor fails to meet specified performance, it shall be repaired or replaced as soon as reasonably possible, but no later than seven days after it was first detected by any employee at the facility unless written permission is obtained from the TCEQ Midland Regional Office which allows for a longer repair or replacement time. The holder of this permit shall develop an operation and maintenance program (including stocking necessary spare parts) to ensure that the continuous monitors are available as required.

Recordkeeping Requirements

20. The following records shall be kept at the plant for the life of the permit. All records required in this permit shall be made available at the request of personnel from the TCEQ, EPA, or any air pollution control agency with jurisdiction.

    A. A copy of this permit.

    B. Permit application dated May 13, 2013 and subsequent representations submitted to the TCEQ.

    C. A complete copy of the testing reports and records of the initial performance testing completed pursuant to Special Condition No. 15 to demonstrate initial compliance.

    D. Stack sampling results or other air emissions testing (other than CEMS data) that may be conducted on units authorized under this permit after the date of issuance of this permit.

21. The following records, written or electronic, shall be maintained at the plant site on a five-year rolling basis and be made readily available at the request of personnel from the TCEQ or any air pollution control agency with jurisdiction:

    A. Records to show compliance with the applicable requirements specified in Special Condition No. 4.

    B. Records to show compliance with the applicable requirements specified in Special Condition No. 5

C. Records of natural gas fuel usage and the sulfur content according to the fuel suppliers for the CTs to show compliance with Special Condition Nos. 7 and 17.

D. Records of visible emission observations and, if required, opacity readings as specified in Special Condition No. 9.

E. Records of NO_x, CO, and O_2 CEMS emissions data to demonstrate compliance with the emission rates listed in the MAERT.

F. Records of the hours of operation and sulfur content of diesel fuel fired in the firewater pump engine, pursuant to Special Condition Nos. 6C and 7C.

G. Records of each turbine's operating hours on a monthly and rolling 12-month basis to show compliance with Special Condition No. 6D.

H. Records of dates and times of CT MSS to demonstrate compliance with Special Condition No. 12.

I. Records of monitored or calculated MSS emissions to demonstrate compliance with Special Condition No. 13.

J. Files of all CEMS quality assurance measures, calibration checks, adjustments and maintenance performed on these systems to demonstrate compliance with Special Condition Nos. 16 and 19.

Reporting

22. The holder of this permit shall submit to the TCEQ Midland Regional Office and the Air Enforcement Branch of the EPA in Dallas semiannual reports as described in 40 CFR § 60.7. Such reports are required for each emission unit which is required to be continuously monitored pursuant to this permit.

Date: ___

Attachment A

Permit Nos. 110423 and PSDTX1366

Inherently Low Emitting (ILE) Planned Maintenance Activities

	Emissions				
Planned Maintenance Activity	VOC	NO_x	CO	PM	SO_2
Water-based washing	x				
Miscellaneous particulate filter maintenance[1]				x	
Degassing for maintenance of storage vessels storing material with vapor pressure <0.5 psia	x				
Degassing for maintenance of storage vessels storing gasoline or other material with vapor pressure >0.5 psia that does not require clearing of the vessels to allow for entry of personnel	x				
Management of sludge from pits, ponds, sumps, and water conveyances[2]	x				
Organic chemical usage	x				
Inspection, repair, replacement, adjusting, testing, and calibration of analytical equipment, process instruments including sight glasses, meters, gauges, CEMS.	x	x	x		x
Turbine washing – unit offline[3]				x	

Notes:
[1]Includes, but is not limited to process-related building air filters, and combustion turbine air intake filters.
[2]Includes, but is not limited to, management by vacuum truck/dewatering of materials in open pits and ponds, and sumps, tanks and other closed or open vessels. Materials managed include water and sludge mixtures containing miscellaneous VOCs such as diesel, lube oil, and other waste oils.
[3]Involves use of water only

Date: ___

Attachment B

Permit Nos. 110423 and PSDTX1366

Non-ILE Planned Maintenance Activities

Planned Maintenance Activity	EPN	Emissions					
		VOC	NO_x	CO	PM	SO_2	H_2SO_4
Combustion optimization[1]	CT-1 CT-2	x	x	x	x	x	x

Notes:
[1]Includes, but is not limited to, (i) leak and operability checks (e.g., turbine over-speed tests, troubleshooting), (ii) balancing, and (iii) tuning activities that occur during seasonal tuning or after the completion of initial construction, a combustor change-out, a major repair, maintenance to a combustor, or other similar circumstances.

Date: ___

Preliminary Determination Summary

Invenergy Thermal Development LLC
Permit Numbers 110423 and PSDTX1366

I. Applicant

Invenergy Thermal Development LLC
1 S Wacker Drive, Suite 1900
Chicago, IL 60606-4644

II. Project Location

Ector County Energy Center
From Goldsmith, go east on Highway 158 turn north on Holt Road. Turn west on Southwest 3601, and after three miles the facility is on the right
Ector County
Goldsmith, Texas 79741

III. Project Description

The proposed project is to construct and operate two natural gas-fired simple-cycle combustion turbine generators (CTGs) at the Ector County Energy Center (ECEC), located approximately 20 miles northwest of Odessa, Texas, in Ector County. In addition to the CTGs to be installed at the ECEC, a dew-point heater (authorized under permit-by-rule (PBR) § 106.183) for the gas supply for the combustion turbines and an emergency diesel fire water pump will be installed. The CTGs that are being considered for the proposed project are General Electric (GE) 7FA.03 and 7FA.05 models. These models have a nominal base-load electrical power output of 165-193 MW. The new CTGs will operate as peaking units and will be limited to 2500 hours per year of operation each. Dry low-NO_x (DLN) burner combustion technology will be used to reduce the nitrogen oxide (NO_x) emissions from the turbines.

IV. Emissions

The proposed ECEC's maximum annual emissions of federally regulated new source review (FNSR) pollutants subject to review by the Texas Commission on Environmental Quality (TCEQ), in tons per year (tpy), are shown in Table IV-1. These emissions include NO_x, carbon monoxide (CO), volatile organic compounds (VOC), particulate matter (PM), PM less than 10 microns in average diameter (PM_{10}), PM less than 2.5 microns in average diameter ($PM_{2.5}$), sulfur dioxide (SO_2), and sulfuric acid (H_2SO_4). The pollutants NO_x, CO, PM_{10}, $PM_{2.5}$, and SO_2 are criteria pollutants, for which a national ambient air quality standard (NAAQS) has been promulgated. In addition, NO_x and VOC are regulated as criteria pollutants for the NAAQS pollutant ozone, which forms in the atmosphere as a reaction of NO_x and VOC emissions.

Table IV-1: Regulated NSR pollutants, tpy

NO_x	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2	H_2SO_4
157.72	296.36	33.32	67.90	67.90	67.90	70.85	32.54

The PM_{10} and $PM_{2.5}$ emissions are subsets of PM, and are broken out separately because these size fractions are regulated separately with respect to allowable concentrations in the air around the plant. The predicted concentrations of these pollutants are discussed in Section VII. The listed PM_{10}, and $PM_{2.5}$ emissions include solid (filterable) and liquid (condensable) material. As a submicron liquid material, the H_2SO_4 emissions are a subset of each of the PM size categories.

The emissions from routine maintenance, startup, and shutdown (MSS) activities are part of the permit application and have been reviewed. The maximum allowable emission rate table (MAERT) has separate hourly emission limits for normal and MSS operations for each CTG. The annual emission limits combine normal and MSS operation emissions into a single limit for each CTG.

V. Federal Applicability

The United States Environmental Protection Agency (EPA) classifies Ector County as "unclassifiable/attainment" or "better than national standards" for the criteria pollutants identified in Table IV-1. Because the ambient air in the county where the facility will be located is considered to attain the NAAQS, federal nonattainment permit review does not apply.

The EPA's Prevention of Significant Deterioration (PSD) rules require Invenergy to obtain a federal PSD permit. PSD applies to major new or modified sources located in attainment areas. The purpose of PSD is to prevent areas with clean air from degrading to the limit of the NAAQS. A PSD major new source includes a new source in any of 27 named source categories that has the potential to emit 100 tpy of a FNSR pollutant. The ECEC belongs to the named source category of "fossil fuel-fired steam electric plant of more than 250 million British thermal units per hour heat input." As shown in Table IV-1, the ECEC has proposed emissions of 100 tpy or more of a FNSR pollutant. PSD review is required for each of the pollutants in Table IV-1 except for VOC since it is below its significant emission rate.

VI. Control Technology Review

As part of the best available control technology (BACT) review, the TCEQ evaluates information from the EPA's RACT/BACT/LAER Clearinghouse (RBLC), on-going permitting in Texas and other states, and the TCEQ's continuing review of emissions control developments.

NOx Emissions

Emissions of NO_x from combustion turbines are generated through the oxidation of nitrogen in the high-temperature combustion zones and will be controlled with DLN combustors in each model of turbine. This method of NO_x control is considered a combustion control as it is designed to minimize combustion temperatures by providing a lean pre-mixed air-fuel mixture, where air and fuel are combined before entering the combustor. This design minimizes fuel-rich pockets and allows the excess air to act as a heat sink, thus lowering the combustion zone temperatures to minimize thermal NO_x formation. Invenergy proposes to reduce NO_x emissions from the proposed simple-cycle peaking units through the use of this combustion technology.

A search of the RBLC returned 21 projects for which natural gas-fired simple-cycle units were permitted since January 1, 2007, with all 21 listing a NO_x emission limit. The RBLC showed NO_x emission limits ranging from 2.5 to 25 ppmvd @15% O_2.

Further review of the RBLC showed that six simple-cycle projects were permitted with a NO_x emission limit of 2.5 ppmvd, based on the use of selective catalytic reduction (SCR) control technology, but all of these projects are located in ozone nonattainment areas (three in New Jersey and three in Southern California) and their NO_x emission limits are Lowest Achievable Emission Rate (LAER) - based limits and not BACT. Excluding these LAER limits, the next lowest permitted NO_x limit listed in the RBLC is 5 ppmvd, for the Black Hills Power, Cheyenne Prairie Generating Station (BHP-Cheyenne) in Laramie County, Wyoming. Although the BHP-Cheyenne simple-cycle unit (a GE LM6000) was initially intended to be operated solely as a peaking unit, the issued permit authorizes BHP to also operate the turbine as a base-load unit (i.e., no restrictions on annual hours of operation), which is the ultimate plan for this BHP-Cheyenne unit. Excluding the BHP-Cheyenne simple-cycle unit, the next lowest permitted NO_x limits in the RBLC are 9 ppmvd. Review of these BACT determinations shows that the 9 ppmvd limit is achieved through use of either DLN burner combustion technology or the combination of low-NO_x burners and water injection.

According to the TCEQ's current combustion source BACT requirements, Tier I BACT for NO_x emissions from gas-fired simple-cycle combustion turbines ranges from 5.0 to 9.0 ppmvd @15% O_2. However, the guidance acknowledges that a higher BACT limit could be appropriate for simple cycle units used in peaking operations. This guidance is reflected in the TCEQ's recent BACT determinations for issued permits, for simple-cycle gas turbines.

A review of the information on the TCEQ's turbine list, in conjunction with review of permit information available through the Agency's air permit websites, showed that NO_x limits for all but two simple cycle units for which state or PSD permits were recently issued was 9 ppmvd @15% O_2 on a 24-hour rolling average basis. This corresponds to the NO_x emissions performance that GE represents for the DLN combustor-equipped GE 7FA.03/05 models that Invenergy is considering.

One of the two accepted simple cycle units referred to above is a GE 7EA turbine unit to be operated by NRG at its W.A. Parish Electric Generating Station. With DLN technology, the GE 7EA unit can achieve a 5 ppmvd NO_x emission rate - a lower rate than the GE 7FA unit can achieve with DLN. This is primarily due to the fact that GE offers a type of DLN for the 7EA turbines that is capable of achieving NO_x emission levels below 5 ppm without the use of SCR. A similar type of DLN is not available for the 7FA turbines.

The GE 7EA model is not suitable for the Invenergy project as it does not meet the project design power requirements due to its maximum load limitation. The GE 7EA is a nominal 80-MW unit as opposed to the nominal 165/193-MW output of the GE 7FA.03/05 models being considered for the Invenergy project.

The other accepted unit, natural gas-fired expansion turbines manufactured by Dresser Rand, authorized by the TCEQ under a Standard Permit for the Apex Bethel Energy Center (Apex), cannot meet a 9-ppmv NO_x limit with DLN burner combustion technology alone; this level of NO_x emissions can only be achieved with the use of SCR which reduces NO_x emissions below 9 ppmvd. Although no ppmv limit has been set for NO_x in the standard permit for Apex, the NO_x emission rate reported in lb/MWh in the TCEQ's technical review of the application is approximately 10 times lower than the NO_X emission rate for the turbine design considered for Invenergy.

Based on the information summarized above, Invenergy proposes to satisfy BACT for NO_x emissions from the proposed simple-cycle units through the use of DLN burner combustion technology. With this type of emissions control, NO_x emissions will not exceed 9 ppmvd @15% O_2, on a 3-hour rolling average basis, excluding periods of startup and shutdown. Invenergy's proposed NO_x emissions performance is equal to the lowest BACT emission rate in recent permits issued for similar simple-cycle peaking units and technologies located in ozone attainment counties both inside and outside Texas. (Units in ozone non-attainment areas were excluded because LAER-based limits do not represent BACT.) Therefore, the proposed emission rate satisfies TCEQ's BACT requirements at the Tier 1 level.

Invenergy will demonstrate that BACT for NO_x is achieved through the initial stack testing of each combustion turbine and by the use of continuous emissions monitoring systems (CEMS) as specified under 40 CFR Part 75.

CO Emissions

Combustion is a thermal oxidation process in which carbon and hydrogen in the fuel combine with oxygen to primarily form carbon dioxide (CO_2) and water vapor. Emissions of CO are the result of incomplete combustion of the carbon in a fuel. The primary factors influencing the generation of CO emissions are temperature and fuel residence time within the combustion zone. Invenergy proposes to minimize CO emissions from the proposed simple-cycle peaking units through the use of operating procedures directed at the most efficient levels of operation consistent with minimizing emissions of NO_X; i.e., good combustion practices - controlled fuel/air mixing and sufficient temperature and gas residence time.

A search of the RBLC showed 17 permits listed as issued since January 1, 2007 with CO emission limits for natural gas-fired simple-cycle units; 15 permits showed ppm-based emission limits. The RBLC showed CO emission limits ranging from 4.0 to 63.0 ppmvd @15% O_2. The lowest permitted CO limits - 4.0 ppmvd @15% O_2 for Great River Energy Elk River Station (GRE-Elk) in Minnesota and 4.1 ppmvd @15% O_2 for the Progress Energy Florida Bartow Power Plant (PEF) - are achieved with "good combustion practices." For the GRE-Elk units, the 4.0 ppmvd emission limit applies only to turbine loads of 70 percent or greater; for turbine loads between 60 and 70 percent, a 10-ppmvd emission limit applies. For the PEF-Bartow unit (a simple cycle Siemens SGT6-5000F turbine), PEF proposed in their permit application a similar dual emission limit approach for natural gas-firing: 4 ppmvd @15% O_2 for a turbine load range of 70-100% and 10 ppmvd @15% O_2 for a turbine load range of 60-70%. However, unlike the Minnesota Pollution Control Agency, the Florida Department of Environmental Protection ultimately permitted the project with only one emission limit: 4.1 ppmvd @15% O_2.

Three New Jersey projects listed in the RBLC are each permitted at 5 ppmvd @15% O_2 and the BHP-Cheyenne simple-cycle unit is permitted at 6 ppmvd @15% O_2, with all of these projects using oxidation catalyst controls to achieve these limits. As mentioned previously, unlike a true peaking unit, the BHP-Cheyenne simple-cycle unit is permitted to operate as a base-loaded unit (i.e., 8,760 hours per year), and is expected to do so in the future. Also mentioned previously, the three New Jersey projects are located in an ozone nonattainment area. Therefore, the concern for minimizing VOC emissions provides the impetus for oxidation catalyst controls, which reduces both VOC and CO emissions. Notwithstanding the RBLC listing for the Shady Hills Power project, the next lowest permitted CO emission limits in the RBLC are 9 ppmvd @15% O_2, based on good combustion practices.

According to the TCEQ's current combustion source BACT requirements, Tier I BACT for CO emissions from gas-fired simple-cycle combustion turbines is 9 to

25 ppmvd @15% O_2. Also, TCEQ's recent BACT determinations, as shown in the agency's most recent "gas turbine permit list" for simple-cycle gas turbines, demonstrate that CO emission limits for simple-cycle units range from 8 to 29 ppmvd @15% O_2 (without the use of an add-on control technology; e.g., oxidation catalyst).

Based on the body of findings summarized above, Invenergy proposes to satisfy BACT for CO emissions from the proposed simple-cycle units through the use of good combustion practices - controlled fuel/air mixing and sufficient temperature and gas residence time. Given the potential variation in load and associated CO emission levels during normal operations for the combustion turbines, Invenergy is proposing to meet a CO emissions level of 9 ppmvd @15% O_2. This limit is expressed as 3-hour average and excludes periods of startup and shutdown. Given that Invenergy's proposed CO emission rate is at the low end of the range of TCEQ BACT-based required emission levels, BACT is satisfied at the Tier 1 level.

Invenergy will demonstrate that BACT for CO is achieved through the initial stack testing and proper operation of the units.

VOC Emissions

Similar to CO emissions generation, VOC emissions will result from the incomplete combustion of the natural gas. The primary factors influencing the generation of VOC emissions are temperature and fuel residence time within the combustion zone. Invenergy proposes to minimize VOC emissions from the proposed simple-cycle peaking units through the use of operating procedures directed at the most efficient levels of operation; i.e., good combustion practices - controlled fuel/air mixing and sufficient temperature and gas residence time.

A search of the RBLC showed 13 permits issued since January 1, 2007 with VOC emission limits for natural gas-fired simple-cycle units; 10 of these permits impose ppm-based emission limits (see Appendix B-3 of the permit application). The RBLC showed VOC emission limits ranging from 1.2 to 5 ppmvd @15% O_2. The lowest permitted VOC limit - 1.2 ppmvd @15% O_2 for PEF - is achieved with "good combustion practices." For the PEF unit (a Siemens SGT6-5000F turbine), PEF proposed in their permit application a dual emission limit approach for natural gas-firing: 1 ppmvd @15% O_2 for a turbine load range of 70-100% and 4 ppmvd @15% O_2 for a turbine load range of 60-70%. The Florida Department of Environmental Protection ultimately permitted the project with only one emission limit: 1.2 ppmvd @15% O_2. The next lowest permitted VOC emission limit in the RBLC is 2.0 ppmvd @15% O_2, based on the use of an oxidation catalyst, for the aforementioned three Southern California projects.

According to the TCEQ's current combustion source BACT requirements, Tier I BACT for VOC emissions from gas-fired simple-cycle combustion turbines is 2 ppmvd @15% O_2.

Based on the findings summarized above, Invenergy proposes to satisfy BACT for VOC emissions from the proposed simple-cycle units through the use of good combustion practices - controlled fuel/air mixing and sufficient temperature and gas residence time. Given the potential variation in load and associated VOC emission levels during normal operations for the combustion turbines, Invenergy is proposing to meet a VOC emissions level of 2 ppmvd @15% O_2. Given that the proposed VOC emission rate is equal to the TCEQ BACT-based required emission level, BACT is satisfied at the Tier 1 level.

Invenergy will demonstrate that BACT for VOCs is achieved through the initial stack testing and proper operation of the combustion turbines.

PM/PM10/PM2.5 Emissions

In general, particulate matter (PM) is emitted from combustion processes as a result of inorganic constituents contained in the fuel, PM in the inlet air, and incomplete combustion of the organic constituents in the fuel. Because the combustion turbines will fire only natural gas, $PM/PM_{10}/PM_{2.5}$ emissions are anticipated to be relatively low. Consistent with recent permits for simple cycle turbines, for which the TCEQ has determined that firing pipeline quality natural gas is BACT for PM, Invenergy will fire pipeline-quality natural gas and apply good combustion practices to minimize emissions of $PM/PM_{10}/PM_{2.5}$ from the proposed units.

Invenergy will demonstrate that BACT for $PM/PM_{10}/PM_{2.5}$ is achieved through the initial stack testing and proper operation of the combustion turbines.

Sulfur Compound Emissions

Emissions of SO_2 will occur as a result of oxidation of sulfur in the natural gas fired in the combustion turbine, with the majority of the sulfur converted to SO_2 and a small portion to H_2SO_4. Consistent with recent permits for simple cycle turbines, Invenergy will minimize SO_2 and H_2SO_4 emissions in the proposed units by firing pipeline-quality natural gas with a sulfur content not exceeding 1 grain sulfur per 100 standard cubic feet (scf) on a short-term and annual basis. This is BACT for SO_2 and H_2SO_4 emissions.

Invenergy will demonstrate that BACT for SO_2 and H_2SO_4 is achieved through the maintenance of records of contractual limits on sulfur content, valid purchase contracts, tariff sheets, or transportation contracts for the fuel which show sulfur content.

Maintenance, Startup, and Shutdown Emissions

Operation of the combustion turbines will result in emissions from startup and shutdown of the units. Each combustion turbine unit will be started up and shut down in a manner that minimizes the emissions during these events. BACT will be achieved by minimizing the duration of the startup and shutdown events to 60 minutes per event. CTG optimization activities will result in emissions that will be subject to the hourly emission limits for MSS activities from CTGs listed on the MAERT. Emissions from these activities shall not exceed more than eight hours per calendar day.

BACT for Lube Oil Mist Vent Emissions

The heating of recirculating lubrication oil in the gas turbine and steam turbine housing generates oil vapor and oil condensate droplets in the oil reservoir compartments. The venting of turbine lubrication oil is a minor source of VOC and PM emissions. These emissions will be controlled with oil mist eliminators, which are BACT for emissions from these vents.

BACT for Fugitive Natural Gas and Lube Oil Component Leaks

Fugitive VOC emissions were estimated for metering, compression, and piping components in natural gas and lube oil service. Invenergy proposes that the proper design of the fuel and lube oil delivery and handling systems and the use of best operating practices satisfy the requirements of BACT for fugitive emissions from components in natural gas and lube oil service.

BACT for Diesel-Fired Equipment

BACT for the diesel-fired fire-water pump engine will be achieved through the installation of an engine that meets the vendor certification requirements of 40 CFR 60, Subpart IIII, through the proper operation and maintenance of the engine, and through the burning of diesel fuel meeting the sulfur requirements of 40 CFR § 80.510.

BACT for Diesel Storage Tank

The diesel storage tank is a 500 gallon fixed roof tank with a submerged fill pipe. The exterior surface of the tank will be either white or aluminum, which is BACT for this size and type of storage tank.

VII. Air Quality Analysis

The air quality analysis (AQA) is acceptable for all review types and pollutants. The results are summarized below.

A. De Minimis Analysis

A De Minimis analysis was initially conducted to determine if a full impacts analysis would be required. The De Minimis analysis modeling results indicate that 1-hr and annual NO_2, 24-hr and annual PM_{10}, and 24-hr and annual $PM_{2.5}$ exceed the respective de minimis concentrations and require a full impacts analysis. The De Minimis analysis modeling results for 1-hr and 8-hr CO, and 1-hr, 3-hr, 24-hr, and annual SO_2 indicate that the project is below the respective de minimis concentrations and no further analysis is required.

The justification for selecting the EPA's interim 1-hr NO_2 and 1-hr SO_2 De Minimis levels was based on the assumptions underlying EPA's development of the 1-hr NO_2 and 1-hr SO_2 De Minimis levels. As explained in EPA guidance memoranda[1,2], the EPA believes it is reasonable as an interim approach to use a De Minimis level that represents 4% of the 1-hr NO_2 and 1-hr SO_2 NAAQS.

The applicant provided an evaluation of ambient $PM_{2.5}$ monitoring data, consistent with draft EPA guidance for $PM_{2.5}$[3], for using the $PM_{2.5}$ De Minimis levels. See the discussion below in the air quality monitoring section for additional information on the evaluation of ambient $PM_{2.5}$ monitoring data.

While the De Minimis levels for both the NAAQS and increment are identical for $PM_{2.5}$ in the table below, the procedures to determine significance (that is, predicted concentrations to compare to the De Minimis levels) are different. This difference occurs because the NAAQS for $PM_{2.5}$ are statistically-based, but the corresponding increments are exceedance-based.

Table 1. Modeling Results for PSD De Minimis Analysis in Micrograms Per Cubic Meter (µg/m³)

Pollutant	Averaging Time	GLCmax (µg/m³)	De Minimis (µg/m³)

[1] www.epa.gov/region07/air/nsr/nsrmemos/appwso2.pdf
[2] www.epa.gov/nsr/documents/20100629no2guidance.pdf
[3] www.epa.gov/ttn/scram/guidance/guide/Draft_Guidance_for_PM25_Permit_Modeling.pdf

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	De Minimis ($\mu g/m^3$)
SO_2	1-hr	5.6	7.8
SO_2	3-hr	7.1	25
SO_2	24-hr	3.2	5
SO_2	Annual	0.3	1
PM_{10}	24-hr	6.2	5
PM_{10}	Annual	1.2	1
$PM_{2.5}$ (NAAQS)	24-hr	5	1.2
$PM_{2.5}$ (NAAQS)	Annual	1.4	0.3
$PM_{2.5}$ (Increment)	24-hr	6.2	1.2
$PM_{2.5}$ (Increment)	Annual	1.2	0.3
NO_2	1-hr	43	7.5
NO_2	Annual	2.2	1
CO	1-hr	190	2000
CO	8-hr	57	500

For the 1-hr NO_2 and 1-hr SO_2 analyses, the GLCmax are the highest five-year averages of the maximum predicted 1-hr concentrations determined for each receptor across five years of meteorological data.

The GLCmax for 3-hr SO_2, 24-hr SO_2, annual SO_2, CO, PM_{10}, $PM_{2.5}$ (Increment), and annual NO_2 are the maximum predicted concentrations across five years of modeling.

The 24-hr $PM_{2.5}$ (NAAQS) GLCmax is the highest five-year average of the maximum predicted 24-hr concentrations determined for each receptor across five years of meteorological data. The annual $PM_{2.5}$ (NAAQS) GLCmax is the highest five-year average of the maximum predicted annual concentrations determined for each receptor across five years of meteorological data.

B. Air Quality Monitoring

The De Minimis analysis modeling results indicate that 24-hr SO_2, 24-hr PM_{10}, annual NO_2, and 8-hr CO are below their respective monitoring significance levels.

Table 2. Modeling Results for PSD Monitoring Significance Levels

Pollutant	Averaging Time	GLCmax (µg/m^3)	Significance (µg/m^3)
SO_2	24-hr	3.2	13
PM_{10}	24-hr	6.2	10
NO_2	Annual	2.2	14
CO	8-hr	57	575

The GLCmax are the maximum predicted concentrations associated with five years of meteorological data.

The applicant evaluated ambient $PM_{2.5}$ monitoring data to satisfy the requirements for the pre-application air quality analysis. Background concentrations for $PM_{2.5}$ were obtained from the EPA AIRS monitor 481350003 located at Barrett & Monahans Streets, Odessa, Ector County. The applicant calculated a three-year average (2011-2013) of the 98th percentile of the annual distribution of the 24-hr concentrations for the 24-hr value (21.5 µg/m^3). The three-year average (2011-2013) of the annual mean concentrations was used for the annual value (9.1 µg/m^3). This monitor is reasonable based on the applicant's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

C. National Ambient Air Quality Standards (NAAQS) Analysis

The De Minimis analysis modeling results indicate that 24-hr and annual PM_{10}, 24-hr and annual $PM_{2.5}$, and 1-hr and annual NO_2 exceed the respective de minimis concentrations and require a full impacts analysis. The full NAAQS modeling results indicate the total predicted concentrations will not result in an exceedance of the NAAQS.

Table 3. Total Concentrations for PSD NAAQS (Concentrations > De Minimis)

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Conc. = [Background + GLCmax] ($\mu g/m^3$)	Standard ($\mu g/m^3$)
PM_{10}	24-hr	4.7	121.1	135.8	150
$PM_{2.5}$	24-hr	5.1	21.5	26.6	35
$PM_{2.5}$	Annual	1.4	8	9.4	12
NO_2	1-hr	121	52	173	188
NO_2	Annual	3.5	4.9	8.4	100

The 24-hr PM_{10} GLCmax is the maximum high, sixth high (H6H) 24-hr predicted concentration across five years of modeling.

The 24-hr $PM_{2.5}$ GLCmax is the highest five-year average of the maximum 24-hr predicted concentrations determined for each receptor. The annual $PM_{2.5}$ GLCmax is the highest five-year average of the maximum predicted annual concentrations determined for each receptor.

The 1-hr NO_2 GLCmax is the highest five-year average of the high, eighth high (H8H) maximum daily 1-hr predicted concentrations determined for each receptor. The annual NO_2 GLCmax is the maximum annual predicted concentration across five years of modeling.

Background concentrations for PM_{10} were obtained from the EPA AIRS monitor 481410038 located at 301 Midway Dr., El Paso, El Paso County. The high, second high (H2H) 24-hr concentration from 2013 was used for the 24-hr value. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative analysis of source emissions near the project site.

$PM_{2.5}$ background concentrations were obtained from the EPA AIRS monitor 481350003 located at Barrett & Monahans Streets, Odessa, Ector County. The three-year average (2011-2013) of the 98th percentile of the annual distribution of the 24-hr concentrations was used for the 24-hr value. The annual mean concentration from 2013 was used for the annual value. Though the applicant did not use the three-year average (2011-2013) of the annual mean concentrations for the annual value (9.1 $\mu g/m^3$), using the three-year average would still have total predictions that are less than the NAAQS. This monitor is reasonable based on the applicant's quantitative review of emissions sources in the surrounding area of the monitor site relative to the project site.

Background concentrations for NO_2 were obtained from the EPA AIRS monitor 483091037 located at 4472 Mazanec Rd., Waco, McLennan County. The three-year average (2011-2013) of the 98th percentile of the annual distribution of the daily maximum 1-hr concentrations was used for the 1-hr value. The annual mean concentration from 2013 was used for the annual value. The use of this monitor is reasonable based on a comparison of county-wide emissions, population, and a quantitative analysis of source emissions near the project site.

The applicant performed an analysis on secondary $PM_{2.5}$ formation as part of the PSD AQA. The applicant evaluated the project emissions of $PM_{2.5}$ precursor emissions (NO_x and SO_2). The project will result in a proposed increase of NO_x and SO_2 emissions greater than 40 tons per year (tpy).

Significant secondary formation of $PM_{2.5}$ due to the proposed NO_x and SO_2 emissions is not expected based on the following information:

- The predicted SO_2 concentrations are less than De Minimis levels at all modeled receptors, and the predicted 1-hr NO_2 concentrations are less than the interim De Minimis level approximately 1 km from the project site fence line.
- Secondary $PM_{2.5}$ formation occurs as a result of chemical transformations that occur in the atmosphere gradually over time and only a portion of the SO_2 and NO_x emissions would be affected. Furthermore, secondary $PM_{2.5}$ formation from SO_2 and NO_x is unlikely to overlap in time or space with nearby maximum primary $PM_{2.5}$ concentrations associated with the project sources.

Table 4. PSD Ambient Air Quality Analysis for Ozone

Pollutant	Monitor	Averaging Time	Background (ppb)	Standard (ppb)
O_3	481410055	8-hr	64	75

Background concentrations for ozone were obtained from the EPA AIRS monitor 481410055 located at 650 R E Thomason Loop, El Paso, El Paso County. A three-year average (2011-2013) of the annual fourth highest daily maximum 8-hr concentrations was used in the analysis. The use of this monitor for a background concentration of ozone is reasonable based on the applicant's comparison of county-wide emissions and population.

EPA Region 6 has previously recommended a conservative analysis based on the NO_2 modeling to estimate the potential impacts on ozone levels. Considering that it takes time for the NO_2 emissions to react to generate ozone, an evaluation of maximum estimated NO_2 concentrations at a distance of 10-to-11 km downwind from the project source could be used to estimate the potential ozone impacts. EPA Region 6 has recommended that emission sources would have an average ozone yield of up to 2-3 ozone molecules per NO_2 molecule. The applicant used AERMOD to calculate a maximum 8-hr NO_x concentration of 0.343 parts per billion (ppb) at a distance of ten km. Assuming 100% conversion of NO_x to NO_2 and an ozone yield of three ozone molecules per molecule of NO_2, the 8-hr maximum predicted increase of ozone would be 1.03 ppb. Adding 1.03 ppb to the 8-hr ozone background of 64 ppb will result in a total 8-hr ozone concentration that is less than the 8-hr ozone NAAQS of 75 ppb.

D. Increment Analysis

The De Minimis analysis modeling results indicate that 24-hr and annual PM_{10}, 24-hr and annual $PM_{2.5}$, and annual NO_2 exceed the respective de minimis concentrations and require a PSD increment analysis.

Table 5. Results for PSD Increment Analysis

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Increment ($\mu g/m^3$)
PM_{10}	24-hr	5.8	30
PM_{10}	Annual	1.1	17
$PM_{2.5}$	24-hr	5.6	9
$PM_{2.5}$	Annual	1.5	4
NO_2	Annual	3.5	25

The 24-hr GLCmax for PM_{10} and $PM_{2.5}$ are the maximum H2H predicted concentrations across five years of modeling. The annual GLCmax for PM_{10}, $PM_{2.5}$, and NO_2 are the maximum predicted concentrations across five years of modeling.

Based on the evaluation of secondary formation of $PM_{2.5}$ discussed above in the NAAQS Analysis section, the contribution of secondary formation of $PM_{2.5}$ is not expected to be significant.

E. Additional Impacts Analysis

The applicant performed an Additional Impacts Analysis as a part of the PSD AQA. The applicant conducted a growth analysis and determined that population will not significantly increase as a result of the proposed project. The applicant conducted a soils and vegetation analysis and determined that all evaluated criteria pollutant concentrations are below their respective primary and secondary NAAQS. The applicant meets the Class II visibility analysis requirement by complying with 30 TAC 111. The Additional Impacts Analyses are reasonable and possible adverse impacts from this project are not expected.

The ADMT evaluated predicted concentrations from the proposed site to determine if emissions could adversely affect a Class I area. The nearest Class I area, Carlsbad Caverns National Park, is located approximately 175 km from the project site to the west.

The H_2SO_4 24-hr maximum predicted concentration of 0.4 µg/m^3 occurred approximately 70 meters from the fence line towards the north. The H_2SO_4 24-hr maximum predicted concentration occurring at the edge of the receptor grid, 30 km from the proposed sources, in the direction of the Carlsbad Caverns National Park Class I area is 0.02 µg/m^3. The Carlsbad Caverns National Park Class I area is an additional 145 km from the edge of the receptor grid. Therefore, emissions of H_2SO_4 from the proposed project are not expected to adversely affect the Carlsbad Caverns National Park Class I area.

The predicted concentrations of PM_{10}, $PM_{2.5}$, SO_2 and NO_2 for all averaging times, are all less than de minimis levels at a distance of 1.3 km from the proposed sources in the direction of the Carlsbad Caverns National Park Class I area. Carlsbad Caverns National Park is an additional 173.7 km from the location where the predicted concentrations of PM_{10}, $PM_{2.5}$, SO_2 and NO_2, for all averaging times are less than de minimis. Therefore, emissions from the proposed project are not expected to adversely affect the Carlsbad Caverns National Park Class I area.

F. Minor Source NSR and Air Toxics Review

Table 6. Site-wide Modeling Results for State Property Line

Pollutant	Averaging Time	GLCmax ($\mu g/m^3$)	Standard ($\mu g/m^3$)
SO_2	1-hr	11	1021
H_2SO_4	1-hr	1.6	50
H_2SO_4	24-hr	0.4	15

VIII. Conclusion

Invenergy Thermal Development LLC proposes controls and emission limits that represent BACT for the proposed electric generating facility. Modeling analysis indicates that the proposed project will not violate the NAAQS or any PSD increment, nor have any adverse impacts on the public health, soils, vegetation, or Class I areas. The applicant has demonstrated the project meets all applicable rules, regulations and requirements of the Texas and Federal Clean Air Acts. The executive director makes a preliminary recommendation to issue Permit Nos. 110423 and PSDTX1366.