Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the Pinecrest Energy Center, LLC

Permit Number: PSD-TX-1298-GHG

June 2014

This document serves as the statement of basis for the above-referenced draft permit, as required by 40 CFR § 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR § 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On February 28, 2013, Pinecrest Energy Center, LLC (Pinecrest) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for greenhouse gas (GHG) emissions for a proposed construction project. In connection with the same proposed new major stationary source, Pinecrest submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on June 22, 2012. Pinecrest proposes to construct a new natural gas-fired combined-cycle electric generating plant, Pinecrest Energy Center, to be located near Lufkin, Angelina County, Texas. Pinecrest will consist of two natural gas-fired combustion turbines, each exhausting to a heat recovery steam generator (HRSG) to produce steam to drive a shared steam turbine. After reviewing the application, EPA Region 6 has prepared the following SOB and draft air permit to authorize construction of air emission sources at the Pinecrest Energy Center.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that Pinecrest's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations.

EPA's conclusions rely upon information provided in the permit application, supplemental information EPA requested and provided by Pinecrest, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

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Plano, Texas 75093

Facility Physical Address:
1002 East Park Avenue
Lufkin, TX 75904

Contact:
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III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). Texas remains the permitting authority for non-GHG pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Jennifer Huser
Air Permitting Section (6PD-R)
1445 Ross Avenue
Dallas, TX 75202
(214) 665-7347

The Non-GHG PSD Permitting Authority for the State of Texas is:

Air Permits Division (MC-163)
TCEQ
P.O. Box 13087
Austin, TX 78711-3087

IV. Facility Location

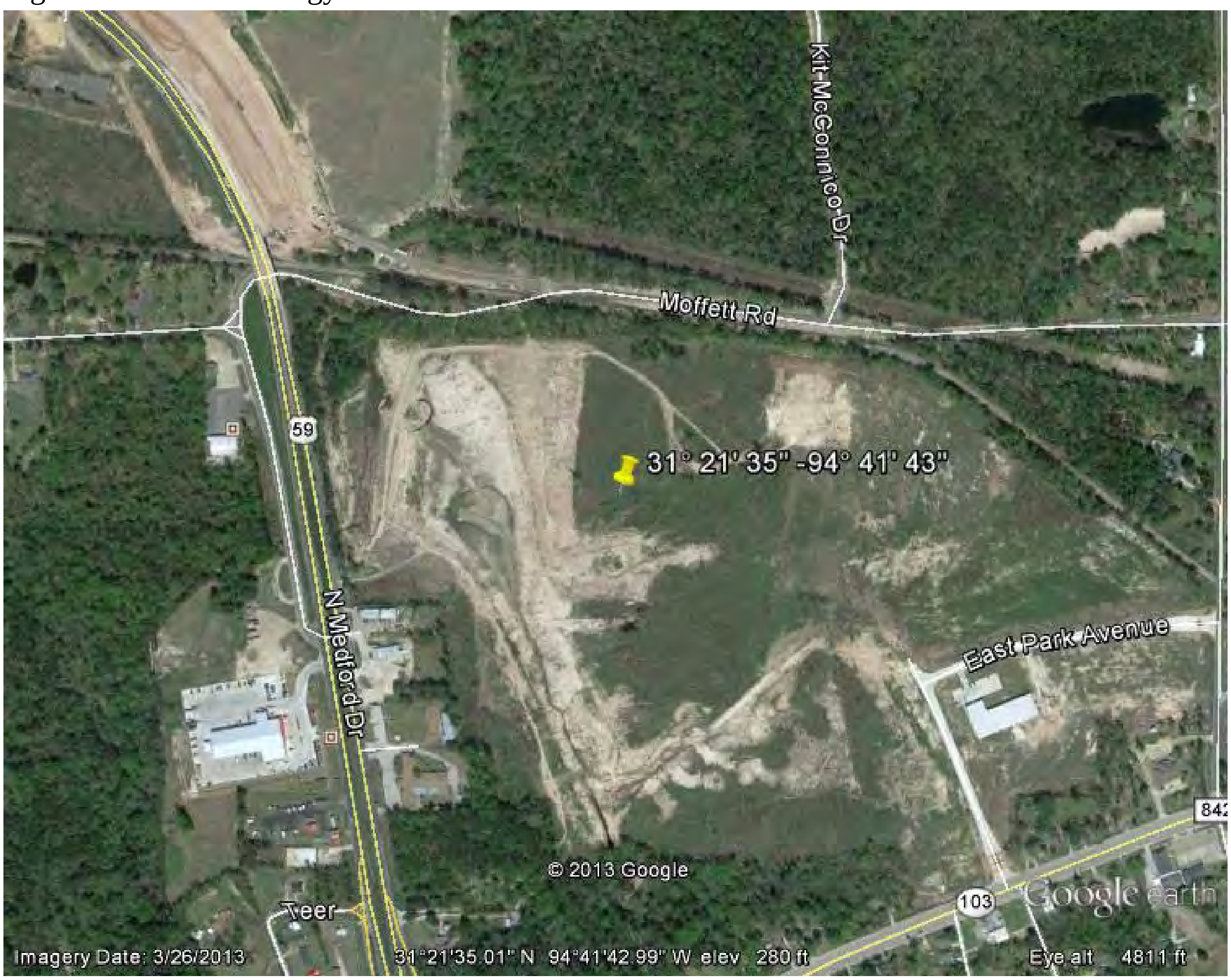
The Pinecrest Energy Center will be located in Angelina County, Texas. Angelina County is currently designated attainment for all criteria pollutants. The nearest Class 1 area is the Caney Creek Wilderness area in Arkansas, which is located well over 100 miles from the site.

The geographic coordinates for this facility are planned to be as follows:

Latitude: 31° 21' 35"
Longitude: 94° 41' 43"

Below, Figure 1 illustrates the proposed facility location for this draft permit.

Figure 1. Pinecrest Energy Center Location



V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes that Pinecrest's application is subject to PSD review for GHGs, because the project will constitute a new stationary source that is otherwise subject to PSD (for another regulated NSR pollutant) and the source has GHG potential to emit (PTE) equal to or greater than 75,000 tons per year (TPY) carbon dioxide equivalent (CO_2e), as described at 40 CFR § 52.21(b)(49)(iv)(*a*). EPA Region 6 implements a GHG PSD FIP for the State of Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

Pinecrest represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will determine that Pinecrest is also subject to PSD review for volatile organic compounds (VOC), nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM, including PM_{10} and $PM_{2.5}$), and sulfuric acid (H_2SO_4). Accordingly, under the circumstances of this project, TCEQ will issue the non-GHG portion of the permit, and EPA will issue the GHG portion.[1]

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have neither required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that 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. We note, however, that TCEQ's PSD permit will address regulated NSR pollutants other than GHGs and therefore should address the additional impacts analysis and Class I area requirements for other pollutants, as appropriate.

VI. Project Description

The proposed GHG PSD permit, if finalized, would authorize Pinecrest to construct a new combined-cycle electric generating plant, Pinecrest Energy Center, in Angelina County, Texas. According to the applicant, Pinecrest will generate 637 - 735 megawatts (MW) of gross electrical power near the City of Lufkin in an efficient manner while increasing the reliability of the electrical supply for the State of Texas. One of the factors in siting the plant is the availability of surface water from the City of Lufkin to be used as cooling water at the plant. The power generating equipment, as well as ancillary equipment that will be sources of GHG emissions at the site, are listed below:

- Two natural gas-fired combustion turbines equipped with lean pre-mix low-NO_x combustors
- Two natural gas-fired duct burner systems equipped with Heat Recovery Steam Generators
- Natural gas piping and metering
- One diesel fuel-fired emergency electrical generator engine
- One diesel fuel-fired fire water pump engine

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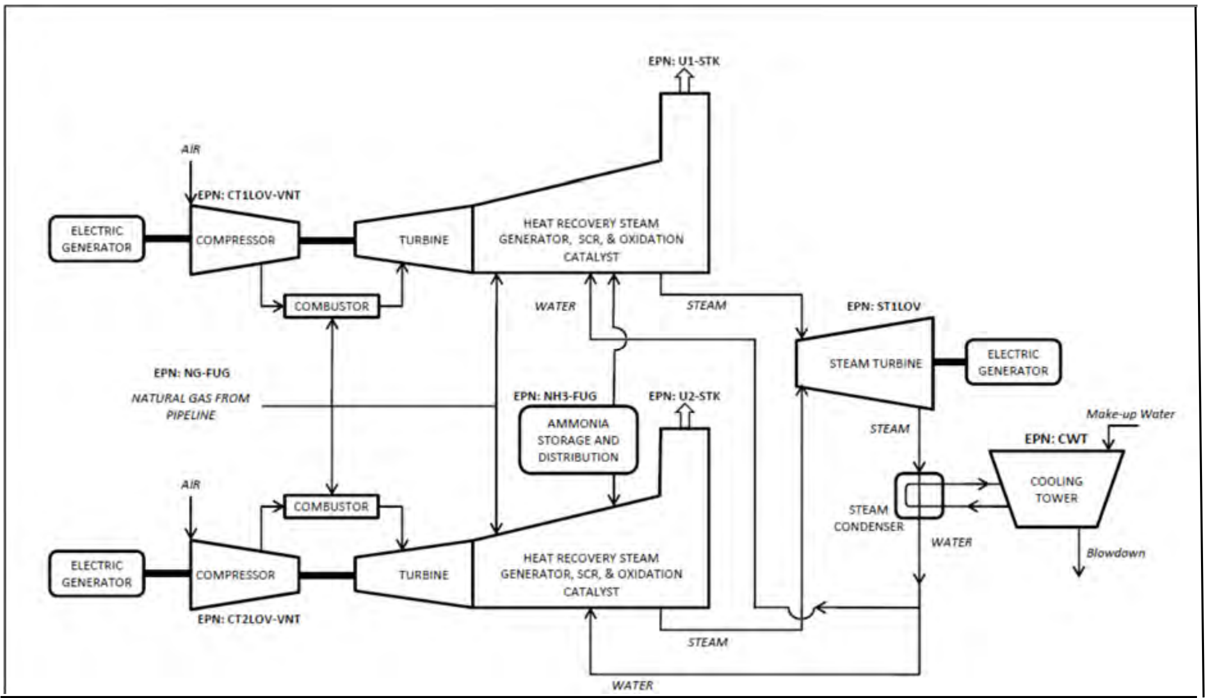
[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

- One natural gas-fired auxiliary boiler
- Electrical equipment insulated with sulfur hexafluoride (SF_6)

Process Description and Process Flow

The following presents a process flow diagram for the two combined-cycle combustion turbines at Pinecrest.



Combustion Turbine Generator

The plant will consist of two identical natural gas-fired combustion turbine generators (CTGs), and the applicant is currently considering three different models: the General Electric 7FA.05, the Siemens SGT6-5000F(4), and the Siemens SGT6-5000F(5). The final selection of the combustion turbine model will likely be made after the permit is issued. Each combustion turbine will exhaust to a heat recovery steam generator (HRSG). Emission point numbers (EPNs) for the combustion turbine/HRSG units are identified as U1-STK and U2-STK. As explained below, the final permit will include BACT limits and related conditions specific to each of the possible turbine models being considered for the project. If a final selection of combustion turbine is made after the public notice begins, and before the issuance of the final permit, EPA will issue a final permit including only the limits for the selected turbine.

The combustion turbine will burn pipeline quality natural gas to rotate an electrical generator to generate electricity. The main components of a combustion turbine generator consist of a compressor, combustor, turbine, and generator. The compressor pressurizes combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the turbine where the gases expand across the turbine blades, driving a shaft to power an electric generator. The exhaust gas will exit the combustion turbine and be routed to the HRSG for steam production.

Heat Recovery Steam Generator

Heat recovered in the HRSG will be utilized to produce steam. Steam generated within the HRSG will drive a steam turbine and associated electrical generator. The HRSG will be equipped with duct burners for supplemental steam production. The duct burners will be fired with pipeline-quality natural gas. The duct burners have a maximum heat input capacity of 750 MMBtu/hr per unit. The exhaust gases from the unit, including emissions from the CT and the duct burners, will exit through a stack to the atmosphere.

The normal duct burner operation will vary from 0 to 100 percent of the maximum capacity. Duct burners will be located in the HRSG prior to the selective catalytic reduction system.

Generation Capacity Overall

Steam produced by each of the two HRSGs will be routed to the steam turbine. The two combustion turbines and one steam turbine will be coupled to electric generators to produce electricity for sale to the Electric Reliability Council of Texas power grid. The maximum base-load electric power output of the GE 7FA.05 is approximately 215 MW, the Siemens SGT6-5000F(4) is approximately 205 MW, and the Siemens SGT6-5000F(5) is approximately 232 MW. The maximum electric power output from the steam turbine is approximately 271 MW for both the GE and Siemens configurations. The units may operate at reduced load to respond to changes in system power requirements and/or stability.

Auxiliary Boiler

One auxiliary boiler (EPN: AUXBLR) will be available to facilitate startup of the combined-cycle units. The auxiliary boiler will have a maximum heat input of 150 MMBtu/hr and will burn pipeline quality natural gas. The auxiliary boiler is proposed to be permitted to operate up to 876 hours per year.

Diesel-Fired Emergency Equipment

The site will be equipped with one nominally rated 1,072-hp diesel-fired emergency generator (EPN: EMGEN1-STK) to provide electricity to the facility in case of power failure. A nominally rated 500-hp diesel-fired firewater pump (EPN: FWP1-STK) will be installed at the site to provide water in the event of a fire. Each emergency engine will be limited to 100 hours of non-emergency operation per year for purposes of maintenance checks and readiness testing.

Natural Gas/Fuel Gas Piping

Natural gas will be delivered to the site via pipeline. Gas will be metered and piped to the new combustion turbines and duct burners. Fugitive emissions (EPN: NG-FUG) from the gas piping components associated with the new CTG/HRSG units will include emissions of methane (CH_4) and carbon dioxide (CO_2). Pinecrest will emit small amounts of GHGs from gaseous fuel venting during turbine shutdown and maintenance from the fuel lines being cleared of fuel. Pinecrest will also emit small amounts of GHGs from the repair and replacement of small equipment and fugitive components.

Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

The generator circuit breakers associated with the proposed units will be insulated with SF_6 (EPN: SF6-FUG). 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 400 lbs of SF_6. The proposed circuit breaker at the generator output will be equipped with 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.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted in accordance with EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed below.

(1) Identify all available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control options;
(4) Evaluate the most effective controls (taking into account the energy, environmental, and economic impacts) and document the results; and
(5) Select BACT.

VIII. Applicable Emission Units for BACT Analysis

The majority of the GHGs associated with the project are from emissions at combustion sources (i.e., combined-cycle combustion turbines, auxiliary boiler, emergency engine, and fire water pump). Stationary combustion sources primarily emit CO_2, and small amounts of N_2O and CH_4. The following equipment is included in this proposed GHG PSD permit:

- Combined-cycle Combustion Turbines (EPNs: U1-STK and U2-STK)
- Auxiliary Boiler (EPN: AUXBLR)
- Emergency Generator (EPN: EMGEN1-STK)
- Fire Water Pump (EPN: FWP1-STK)
- Natural Gas Fugitives (EPN: NG-FUG)
- SF_6 Insulated Equipment (EPN: SF6-FUG)

IX. Combined-Cycle Combustion Turbines (EPNs: U1-STK and U2-STK)

Two new natural gas-fired combined-cycle combustion turbines (EPNs: U1-STK and U2- STK) will be used for power generation. Pinecrest is evaluating three combustion turbine options for this project: General Electric 7FA.05, Siemens SGT6-5000F(4), and Siemens SGT6-5000F(5). The BACT analysis for the turbines considered two types of GHG emission reduction alternatives: (1) energy efficiency processes, practices, and designs for the turbines and other facility components; and (2) carbon capture and storage/sequestration (CCS). The proposed energy efficiency processes, practices, and designs discussed in Step 1 will be the same for the three models being considered. The proposed BACT limits listed in Step 5 section are specific to each turbine model.

As part of the PSD review, Pinecrest provided in the GHG permit application a 5-step top-down BACT analysis for the combustion turbines. EPA reviewed Pinecrest's BACT analysis for the combustion turbines, which is part of the record for this permit (including this Statement of Basis), and EPA has also done its own analysis of BACT for this proposed permit, which is summarized below.

Step 1 – Identify All Available Control Options

<u>(1) **Energy Efficiency Processes, Practices, and Design**</u>

<u>Combustion Turbine:</u>

- *Combustion Turbine Design* – The most efficient way to generate electricity from a natural gas fuel source is the use of a combined-cycle combustion turbine. Furthermore, the three turbine models under consideration for the Pinecrest facility are highly efficient turbines in terms of their heat rate (expressed as number of BTUs of heat energy required to produce a kilowatt-hour of electricity), which is a measure that reflects how efficiently a generator uses heat energy.
- *Periodic Burner Tuning* – Periodic combustion inspections involving tuning of the combustors to restore highly efficient low-emission operation.

- *Reduction in Heat Loss* – 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*– The control system is a digital type supplied with the combustion turbine. 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.

<u>Heat Recovery Steam Generator:</u>

- *Heat Exchanger Design Considerations* – The HRSGs are designed with multiple pressure levels. Each pressure level incorporates an economizer section(s), evaporator section, and superheater section(s). These heat transfer sections are made up of many thin-walled tubes to provide surface area to maximize the transfer of heat to the working fluid.
- *Insulation* – Insulation minimizes heat loss to the surrounding air thereby improving the overall efficiency of the HRSG. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high-temperature steam and water lines, and typically to the bottom portion of the stack.
- *Minimizing Fouling of Heat Exchange Surfaces* – Filtration of the inlet air to the combustion turbine is performed to minimize fouling. Additionally, cleaning of the tubes is performed during periodic outages. By reducing the fouling, the efficiency of the unit is maintained.
- *Minimizing Vented Steam and Repair of Steam Leaks* – Steam is vented from the system from deaerator vents, blowdown tank vents, and vacuum pumps/steam jet air ejectors. These vents are necessary to improve the overall heat transfer within the HRSG and condenser by removing solids and air that potentially blanket the heat transfer surfaces and lower the equipment's performance. Steam leaks are repaired as soon as possible to maintain facility performance.

<u>Steam Turbine:</u>

- *Use of Reheat Cycles* – Reheat cycles are employed to minimize the moisture content of the exhaust steam. This cycle reheats partially expanded steam from the steam turbine.
- *Use of Exhaust Steam Condenser* – The exhaust steam is saturated under vacuum condition by the use of a condenser. The condensing steam creates a vacuum in the condenser, which increases steam turbine efficiency.
- *Efficient Blading Design and Turbine Seals* – Blade design has evolved for high-efficiency transfer of the energy in the steam to power generation. Blade materials are

also important components in blade design, and allow for high-temperature and large exhaust areas to improve performance. The steam turbines have a multiple steam seal design to obtain the highest efficiency from the steam turbine.

- *Efficient Steam Turbine Generator Design* – The generators for modern steam turbines are cooled, allowing for the highest efficiency of the generator and resulting in an overall high-efficiency steam turbine. The cooling method for the Pinecrest steam turbine will be either totally enclosed water to air cooling or hydrogen cooling.

Other Plant-wide Energy Efficiency Features

Pinecrest has proposed a number of other measures that help improve overall energy efficiency of the facility (and thereby reducing GHG emissions from the emission units), including:

- *Fuel Gas Preheating* – The overall efficiency of the combustion turbine is increased with increased fuel inlet temperatures.
- *Drain Operation* – Drains are required to allow for draining the equipment for maintenance, and also allow condensate to be removed from steam piping and drains. Closing the drains as soon as the appropriate steam conditions are achieved will minimize the loss of energy from the cycle.
- *Multiple Combustion Turbine/HRSG Trains* – Multiple trains allow the unit to achieve higher overall plant part-load efficiency by shutting down a train operating at less efficient part-load conditions and ramping up the remaining train to high-efficiency full-load operation.
- *Boiler Feed Pump Variable Speed Drives* – To minimize the power consumption at part-loads, variable speed drives will be used, improving the facility's overall efficiency.

(2) **Carbon Capture and Sequestration (CCS)**

CCS is classified as an add-on pollution control technology, which involves the separation and capture of CO_2 from flue gas, pressurizing of the captured CO_2 into a pipeline for transport, and injection/storage within a geologic formation. CCS is generally installed at "facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[2]

CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of

[2] U.S. EPA, Office of Air Quality Planning and Standards, PSD and Title V Permitting Guidance for Greenhouse Gases. March 2011. Available at: http://www.epa.gov/nsr/ghgdocs/ghgpermttingguidance.pdf.

steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for this proposed gas turbine facility. The third approach, post-combustion capture, is the only technology that is available and applicable to gas turbines. As such, post-combustion capture is the sole carbon capture technology considered in this BACT analysis.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating power plant flue gas due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005). Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology (Kvamsdal et al., 2011), and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes (IPCC, 2005). Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on gas turbines (Reddy, Scherffius, Freguia, & Roberts, 2003).

In a typical MEA absorption process, the flue gas is cooled before it is contacted counter-currently with the lean solvent in a reactor vessel. The scrubbed flue gas is cleaned of solvent and vented to the atmosphere while the rich solvent is sent to a separate stripper where it is regenerated at elevated temperatures and then returned to the absorber for re-use. Fluor's Econamine FG Plus process operates in this manner, and it uses an MEA-based solvent that has been specially designed to recover CO_2 from oxygen-containing streams with low CO_2 concentrations typical of gas turbine exhaust (Fluor, 2009). This process has been used successfully to capture 365 tons per day of CO_2 from the exhaust of a natural gas combined-cycle plant previously owned by Florida Power and Light (Bellingham Energy Center), currently owned by NEXTera Energy Resources of which Florida Power and Light is a subsidiary. The CO_2 capture plant was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003). The CO_2 capture operation was discontinued in 2005 due to a change in operations from a baseload unit to a peak load shaving unit, which created technical impediments to continuing to operate the system.

Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[3]

3 We note that EPA's recent proposed rule addressing *Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units* rejected CCS as the best system of emission reduction for nation-wide

Step 2 – Elimination of Technically Infeasible Alternatives

EPA's recent proposed rule addressing Standards of Performance for Greenhouse Gas Emissions from New Stationary Sources: Electric Utility Generating Units concluded that CCS was not the best system of emission reduction for a nation-wide standard for natural gas combined-cycle (NGCC) turbines based on questions about whether full or partial capture CCS is technically feasible for the NGCC source category. 79 Fed. Reg. 1430, 1485 (Jan. 8, 2014). Considering this, EPA is evaluating whether there is sufficient information to conclude that CCS is technically feasible at this specific NGCC source and will consider public comments on this issue. However, because the applicant has provided a basis to eliminate CCS on other grounds, we have assumed, for purposes of this specific permitting action, that potential technical or logistical barriers do not make CCS technically infeasible for this project and have addressed the economic feasibility issues in Step 4 of the BACT analysis in order to assess whether CCS is BACT for this project.

The other control options identified in Step 1 are also considered technically feasible for this project.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Energy efficiency processes, practices, and designs are all considered effective and have a range of efficiency improvements that cannot be directly quantified, and therefore, ranking them is not possible. In assessing CO_2 emission reduction from CCS, it has been reported that CCS could enable large reductions (85-90 percent) of CO_2 emissions from fossil fuel combustion.

Step 4 – Evaluation of Control Options in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

An evaluation of each technically feasible combustion turbine control option follows in order of descending GHG-reduction effectiveness.

Carbon Capture and Storage

Pinecrest developed an initial cost analysis for CCS that estimates the total annual cost of CCS would be $242,608,288 per year, assuming a 90% CO_2 capture. The estimated plant construction cost with CCS is approximately $974,000,000. EPA Region 6 reviewed Pinecrest's CCS cost estimate and believes it adequately approximates the cost of a CCS control. For this project, CCS would cost

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standard for natural gas combined-cycle (NGCC) turbines based on both "insufficient information to determine technical feasibility" and "adverse impact on electricity prices and the structure of the electric power sector." 79 Fed. Reg. at 1485 (Jan. 8, 2014). However, that proposal did not state that CCS was technically infeasible for individual NGCC sources and thus does not conflict with the type of case-by-case PSD BACT analysis (which separates the technical and cost issues) as presented here.

approximately $530 million, which is greater than 100% of the overall cost of the proposed project without CCS ($443,800,000).

Furthermore, the recovery and purification of CO_2 from the stack gases would necessitate significant additional processing, including energy and environmental/air quality penalties, to achieve the necessary CO_2 concentration for effective sequestration. The additional process equipment required to separate, cool, and compress the CO_2 would require a significant additional water and power expenditure. This equipment would include amine scrubber vessels, CO_2 strippers, amine transfer pumps, flue gas fans, an amine storage tank, and CO_2 gas compressors. The additional GHG emissions resulting from additional fuel combustion would either further increase the cost of the CCS system, if the emissions were also captured for sequestration, or reduce the net amount GHG emission reduction, making CCS even less cost effective than expected.

The Southern California Edison Company investigated the application of CCS technologies for natural gas combined-cycle (NGCC) power plants. The report *Technical and Regulatory Analysis of Adding CCS to NGCC Power Plants in California* (November 2010)[4] included a technical analysis of CCS technologies that are commercially available to NGCC units. For NGCC plants to implement a CO_2 capture process, additional equipment would be required due to the low concentration of CO_2 in the flue gas, which in turn translates to significant impacts on the power unit output, efficiency, and possibly the cost of electricity. In its application, Pinecrest explains that operating the proposed NGCC plant with CCS would result in a 7 percent decrease in plant efficiency (49.9 percent to 42.9 percent) and a projected increase in cost-of-electricity (at 85% capacity factor) of 52.5 dollars per megawatt hour (from 73.3 dollars/MWhr to 125.8 dollars/MWhr). The major challenge for post-combustion CO_2 systems is the use of amine driven technologies that require significant heat and power for amine stripping and for compression and drying of the water saturated CO_2 that leaves the stripping unit.

Since the estimated cost of CCS would more than double the cost of the current project, and considering the adverse energy and environmental impacts of CCS, EPA has eliminated CCS as BACT for this project.

<u>Energy Efficiency Measures</u>

None of the Energy Efficiency Measures are eliminated from the BACT review based on adverse economic, environmental, or energy impacts. As noted above, the three turbine models under consideration are some of the most efficient combined-cycle turbines, based on their lower heat rate in comparison to other combustion turbine models. Furthermore, the other energy efficiency measures proposed by Pinecrest make the suite of Energy Efficiency options the preferred option for BACT.

4 Technical and Regulatory Analysis of Adding CCS to NGCC Power Plants in California; Prepared for Southern California Edison Company, November 2010, by CH2MHill

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the turbines:

- Use of Combined-Cycle Power Generation Technology
- Combustion Turbine Energy Efficiency Processes, Practices, and Design
  - Highly Efficient Turbine Design
  - Turbine Inlet Air Cooling
  - Periodic Turbine Burner Tuning
  - Reduction in Heat Loss
  - Instrumentation and Controls
- HRSG Energy Efficiency Processes, Practices, and Design
  - Efficient Heat Exchanger Design
  - Insulation of HRSG
  - Minimizing Fouling of Heat Exchange Surfaces
  - Minimizing Vented Steam and Repair of Steam Leaks
- Steam Turbine Energy Efficiency Processes, Practices, and Design
  - Use of Reheat Cycles
  - Use of Exhaust Steam Condenser
  - Efficient Blading Design
  - Efficient Generator Design
- Plant-wide Energy Efficiency Processes, Practices, and Design
  - Fuel Gas Preheating
  - Drain Operation
  - Multiple Combustion Turbine/HRSG Trains
  - Boiler Feed Pump Fluid Drive Design

BACT Limits and Compliance:

To determine the appropriate heat-input efficiency limit, Pinecrest started with the turbine's design base load net heat rate for combined-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 net heat rates for the combustion turbines being considered for this project are as follows:

- General Electric 7FA.05
  - 7528.8 Btu/kWhr (HHV) without duct burner firing
    8176 Btu/kWhr (HHV) with duct burner firing
- Siemens SGT6-5000F(4)
  - 7649 Btu/kWhr (HHV) without duct burner firing
  - 7945.7 Btu/kWhr (HHV) with duct burner firing

- Siemens SGT6-5000F(5)
  - 7771.7 Btu/kWhr (HHV) without duct burner firing
  - 8124.7 Btu/kWhr (HHV) with duct burner firing

These rates reflect the facility's "net" power production, meaning the amount of power provided to the grid; it does not reflect the total amount of energy produced by the plant, which also includes auxiliary load consumed by operation of the plant. To be consistent with other recent GHG BACT determinations, the net heat rate without duct burner firing is used to calculate the heat-input efficiency limit.

To date, other similar facilities with a GHG BACT limit are summarized in the table below:

Company / Location	**Process Description**	**Control Device**	**BACT Emission Limit / Requirements**	**Year Issued**	**Reference**
Lower Colorado River Authority (LCRA), Thomas C. Ferguson Plant Horseshoe Bay, TX	590 MW combined-cycle combustion turbine and heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine annual net heat rate limited to 7,720 Btu/kWh (HHV) GHG BACT limit of 0.459 tons CO_2/MWh (net) without duct burning. 365-day average, rolling daily for the combustion turbine unit	2011	PSD-TX-1244-GHG
Palmdale Hybrid Power Plant Project Palmdale, CA	570 MW combined-cycle combustion turbine and heat recovery steam generator and 50 MW Solar- Thermal Plant	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine annual net heat rate limited to 7,319 Btu/kWh (HHV) GHG BACT limit of 0.387 tons CO_2/MWh (net)* 365-day average, rolling daily for the combustion turbine unit	2011	SE 09-01
Calpine Russell City Energy Hayward, CA	600 MW combined-cycle power plant	Energy Efficiency/ Good Design & Combustion Practices	Combustion Turbine Operational limit of 2,038.6 MMBtu/kWh	2011	15487

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
PacifiCorp Energy - Lake Side Power Plant Vineyard, UT	629 MW (without duct burning) combined-cycle turbine	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine BACT limit of 950 lb CO_2e/MWh (gross) on a 12-month rolling average basis	2011	DAQE-AN0130310010-11
Kennecott Utah Copper-Repowering South Jordan, UT	275 MW combined combustion	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine BACT limit of 1,162,552 tpy CO_2e rolling 12-month period	2011	DAQE-IN105720026-11
Pioneer Valley Energy Center Westfield, MA	431 MW combined-cycle turbine generator	Energy Efficiency/ Good Design & Combustion Practices	825 lbs CO_2e/MWh_{grid} (initial performance test) 895 lb CO_2e/MWh_{grid} on a 365-day rolling average	2012	052-042-MA15
Calpine Deer Park Energy Center Deer Park, TX	168 MW/180 MW combustion turbine generator with heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	0.460 tons CO_2/MWh on a 30-day rolling average without duct burning.	2012	PSD-TX-979-GHG
Calpine Channel Energy Center Pasadena, TX	168 MW/180 MW combustion turbine generator with heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	0.460 tons CO_2/MWh on a 30-day rolling average without duct burning.	2012	PSD-TX-955-GHG
La Paloma Energy Center Harlingen, TX	637 MW Combined-cycle	Energy Efficiency Good Design & Combustion Practices	Annual Heat Input – 7,861 Btu/kWh 934 lb CO2/MWh	2013	PSD-TX-1288-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
La Paloma Energy Center Harlingen, TX	681 MW Combined-cycle	Energy Efficiency Good Design & Combustion Practices	Annual Heat Input - 7,649 Btu/kWh 909 lb CO2/MWh	2013	PSD-TX-1288-GHG
La Paloma Energy Center Harlingen, TX	735 MW Combined-cycle	Energy Efficiency Good Design & Combustion Practices	Annual Heat Input - 7,679 Btu/kWh 913 lb CO2/MWh	2013	PSD-TX-1288-GHG
FGE Power, LLC Westbrook, TX	1620 MW Combined-cycle turbine generator with duct burner and heat recovery steam generator	Energy Efficiency/ Good Design & Combustion Practices	Annual Heat Input – 7,625 Btu/kWhr (HHV) without duct burner firing 889 lb CO_2/MWh	2014	PSD-TX-1364-GHG

*The Palmdale facility BACT limit is reduced due to the offset of emissions from the use of a 50 MW Solar-Thermal Plant that was part of the permitted project.

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 6% performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls.
- A 3% degradation margin reflecting the variability in operation of auxiliary plant equipment due to use over time.

Design and construction of a combined-cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, 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 and short-term degradation.

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 rates 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, Pinecrest 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. EPA agrees that this degradation rate is comparable to the rates estimated by other natural gas-fired power plants that have received a GHG PSD permit.

Finally, in addition to the heat rate degradation from normal wear and tear on the combustion turbines, Pinecrest is also providing a reasonable compliance margin based on potential degradation in other elements of the combined-cycle plant that would cause the overall plant heat rate to rise (i.e., cause efficiency to fall). Degradation in the performance of the heat recovery steam generator, steam turbine, heat transfer, cooling tower, and ancillary equipment such as pumps and motors is also expected to occur over the course of a major maintenance cycle.

The following BACT limits are proposed:

Turbine Model	Gross Heat Rate, with duct burner firing (Btu/kWh) (HHV)	Output Based Emission Limit (lb CO_2/MWh) gross with duct burning
General Electric 7FA.05	7,925.0	942
Siemens SGT6-5000F(4)	7,649.0	909.2
Siemens SGT6-5000F(5)	7,679.0	912.7

The calculation of the gross heat rate and the equivalent lb CO_2/MWh is provided in Tables 5-1, 5-2, and 5-3 of the application. There is a 3.5% variation from the lowest proposed BACT limit to the highest proposed BACT limit. The BACT limit will not apply during startup conditions, shutdown, or during periods of maintenance (MSS will account for no more than 500 hours of operation a year). The turbines will comply with the BACT limit during all operational conditions, with and without duct burner firing. While energy efficiency will be a consideration for final selection of a turbine, other considerations will include the capacity of the turbine, cost, reliability, and predicted longevity of the turbines. Since the plant heat rate varies according to turbine operating load and amount of duct burner firing, Pinecrest proposes to demonstrate compliance with the proposed heat rate with an annual compliance test, at 100% load, corrected to ISO conditions.

Pinecrest requested the BACT limit to be expressed in lbs CO_2/MWh. When converting the BACT limits to tons CO_2/MWh gives a range of 0.455 tons CO_2/MWh to 0.471 tons CO_2/MWh with duct burning. When compared to other BACT limits established for other combined-cycle/heat recovery steam generating units, the proposed limits for Pinecrest are comparable to the limits established for LCRA, Calpine Deer Park, Calpine Channel Energy Center, Pioneer Valley Energy Center, and PacifiCorp Energy Lake Side Power Plant. The differences in BACT between Pinecrest and LCRA and Cricket Valley Energy Center (CVEC) are related to the net heat rate for the turbines. The net heat rate of the turbines proposed by Pinecrest are higher than those at LCRA and CVEC. The BACT limit proposed for Pinecrest is higher than the limit proposed for Pioneer Valley Energy Center (PVEC). PVEC is more likely to operate at base load conditions, whereas Pinecrest will operate as a load cycling unit. The BACT limit for Pinecrest (without duct burner firing is 0.442 to 0.455 tons CO_2e/MWh) is less than that established for both Calpine facilities (0.46 tons CO_2e/MWh).

On January 8, 2014, EPA proposed New Source Performance Standard (NSPS) 40 CFR Part 60, Subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units, 79 FR 1429) that would control CO_2 emissions from new electric generating units (EGUs).[5] The proposed rule would apply to fossil fuel-fired EGUs that generate electricity for sale and are larger than 25 MW. EPA proposed that new EGUs meet an annual average output-based standard of 1,000 lb CO2/MWh, on a gross basis. The proposed emission rate for the Pinecrest turbines on a gross electrical output basis ranges from 910.1 to 942.9 lb/MWh with maximum duct burner firing. The proposed CO_2 emission rates from the Pinecrest combined-cycle turbines are well within the emission limit proposed in the NSPS.

Pinecrest shall meet the BACT limit, for the chosen combustion turbine, on a 12-month rolling average.

For all combustion turbines considered, the combined-cycle combustion turbine unit will be designed with a number of features to improve the overall efficiency. The additional combustion turbine design features include:

- Inlet evaporative cooling to utilize water to cool the inlet air and thereby increase the turbine's efficiency;
- Periodic burner tuning as part of a regularly scheduled maintenance program to help ensure a more reliable operation of the unit and maintain optimal efficiency;
- A Distributed Control System (DCS) will control all aspects of the turbine's operation, including fuel feed and burner operations, to achieve optimal high- efficiency low-emission performance for full-load and partial-load conditions;
- Insulation blankets are utilized to minimize the heat loss through the combustion turbine shell and help improve the overall efficiency of the machine; and
- Totally enclosed water to air cooling or hydrogen cooling will be used to cool the generators, resulting in a lower electrical loss and higher unit efficiency.

The Heat Recovery Steam Generator (HRSG) energy efficiency processes, practices and designs considered include:

- Energy efficient heat exchanger design. In this design, each pressure level incorporates an economizer section(s), evaporator section, and superheater section(s);

[5] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 79 Fed Reg 1429, January 8, 2014. Available at http://www.gpo.gov/fdsys/pkg/FR-2014-01-08/pdf/2013-28668.pdf

- Addition of insulation to the HRSG panels, high-temperature steam and water lines and to the bottom portion of the stack;
- Filtration of the inlet air to the combustion turbine and periodic cleaning of the tubes (at least every 18 months) is performed to minimize fouling; and
- Minimization of steam vents and repairs of steam leaks.

Within the combined-cycle power plant, several plant-wide, overall energy efficiency processes, practices and designs are included as BACT requirements because the additional operating conditions/practices help maintain the efficiency of the turbine. The requirements include:

- Fuel gas preheating. For the F-class combustion turbine based combined-cycle, the fuel gas is pre-heated to temperature of approximately 300^{o}F with high temperature water from the HRSG;
- Drain operation. Operation drains are controlled to minimize the loss of energy from the cycle but closing the drains as soon as the appropriate steam conditions are achieved;
- Multiple combustion turbine/HRSG trains. Multiple combustion turbine/HRSG trains help with part-load operation. A higher overall plant part-load efficiency is achieved by shutting down trains operating at less efficient part-load conditions and ramping up the remaining train(s) to high-efficiency full-load operation; and
- Boiler feed pump fluid drives. To minimize the power consumption at part-loads, the use of fluid drives or variable-frequency drives are used to minimize the power consumption at part-load conditions

Pinecrest will demonstrate compliance with the CO_2 limit established as BACT by using in-line flow meters and automatically record the data with a data acquisition and handling system to monitor the quantity of fuel combusted in the electric generating unit and performing periodic scheduled fuel sampling pursuant to 40 CFR § 75.10(a)(3)(ii) and the procedures listed in 40 CFR Part 75, Appendix G. Results of the fuel sampling 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 proposed permit also includes an alternative compliance demonstration method in which Pinecrest may install, calibrate, and operate a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions. Because two combustion turbine/heat recovery steam generators will power a single electric generator, the hourly gross electric output from the steam turbine generator shall be apportioned based on either the measured steam load or measured heat input. A plan to demonstrate the apportionment of the gross electric output shall be submitted within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days of the date of initial startup of the combustion turbine generator.

The CO_2 mass emission values shall be calculated over each operational hour of the compliance period and summed. The summed hourly CO_2 mass emission values shall be divided by the combined sum of the total gross electrical output from the steam turbine (as determined by the corresponding apportionment calculations represented in the plan) and the total gross electrical load from the combustion turbine generator. The resulting quotient is added to the sum of quotients of the previous 11 operating months and divided by 12 to determine compliance with the 12-month rolling average.

Pinecrest proposes to determine a site-specific Fc factor using the ultimate analysis and GCV in equation F-7b of 40 CFR Part 75, Appendix F. The site-specific Fc factor will be re-determined annually in accordance with 40 CFR Part 75, Appendix F, § 3.3.6.

The equation for estimating CO_2 emissions as specified in 40 CFR Part 75, Appendix G § 2.2.3 is as follows:

$$W_{CO_2} = (Fc \times H \times Uf \times MW_{CO_2})/2000$$

Where:

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

MW_{CO2} = molecular weight of CO_2, 44.0 lbs/mole

Fc = Carbon-based Fc-Factor, 1040 scf/MMBtu for natural gas or site-specific Fc factor H = hourly heat input in MMBtu, as calculated using the procedure in 40 CFR Part 75, Appendix F § 5

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

Pinecrest is subject to all applicable requirements for fuel flow monitoring and quality assurance pursuant to 40 CFR Part 75, Appendix D, which include:

- Fuel flow meter - Meets an accuracy of 2.0% and is required to be tested once each calendar quarter pursuant to 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 pursuant to 40 CFR 75, Appendix D § 2.3.4.1

This approach is consistent with the CO_2 reporting requirements of 40 CFR Part 98, Subpart D (Mandatory GHG Reporting for Electricity Generation). Furthermore, Pinecrest's proposed CO_2 monitoring method is consistent with the recently proposed New Source Performance Standards, 40 CFR Part 60, Subpart TTTT (Standards of Performance for Greenhouse Gas Emissions From New Stationary Sources: Electric Utility Generating Units), which allow for electric generating units firing gaseous fuel 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 Part 75, Appendix F. If Pinecrest chooses to install and operate the CO_2 CEMS equipped with a volumetric stack gas monitoring system, the applicant shall rely on the data from the CO_2 CEMS for compliance purposes.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the combined-cycle combustion turbines; therefore, additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations will be required to be kept to demonstrate compliance with the emission limits on a 12-month rolling average.

An initial stack test demonstration will be required for CO_2 emissions from U1-STK and U2- STK. Pinecrest will demonstrate compliance with the proposed heat rate with an annual compliance test at 90% load, corrected to ISO conditions. Pinecrest will calculate the average heat rate on an hourly basis consistent with equation F-20 and procedure provided in 40 CFR Part 75, Appendix F § 5.5.2 and the measured gross hourly energy output for the month. Pinecrest will add the quotient to the sum of the quotients of the previous 11 operating months and divide by 12 to determine the 12-month rolling average. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emission are approximately 0.01% of the total CO_2e emissions from the combustion turbines.

X. Auxiliary Boiler (EPN: AUXBLR)

One nominally rated 150 MMBtu/hr auxiliary boiler (EPN: AUXBLR) will be utilized to facilitate startup of the combined-cycle units. The auxiliary boiler will be limited to 876 hours of operation per year.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Use of Low Carbon Fuels* – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions. Natural gas is the lowest carbon fuel available at Pinecrest.
- *Use of Good Operating and Maintenance Practices* – Following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing in the combustion zone; and maintaining the proper air/fuel ratio so that sufficient oxygen is provided for complete combustion of fuel while at the same time preventing introduction of more air than is necessary into the boiler.
- *Energy Efficient Design* – The auxiliary boiler is designed for a thermal efficiency of approximately 80%. The energy efficient design includes insulation to retain heat within the boiler and a computerized process control system that will optimize the fuel/air mixture and limit excess air in the boiler.

- *Low Annual Capacity* – The auxiliary boiler will be used to facilitate the startup of the two combustion turbines and the annual hours of operation will be limited to 876 hours per year.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

All of the energy efficiency related processes, practices, and designs discussed in Step 1 are being proposed. Therefore, a ranking of the control technologies is not necessary.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

As all of the energy efficiency related processes, practices, and designs discussed in Step 1 are being proposed for this project, an examination of the energy, environmental, and economic impacts of the efficiency designs is not necessary.

Step 5 – Selection of BACT

Pinecrest proposes to use natural gas as a low carbon fuel, good operation and maintenance practices, energy efficient design, and low annual capacity as BACT for the auxiliary boiler. The following specific BACT practices are proposed for the heaters:

- Use of low carbon fuel (natural gas). Natural gas will be the only fuel fired in the proposed auxiliary boiler. It is the lowest carbon fuel available for use at Pinecrest.
- Good operation and maintenance practices will include following the manufacturer's recommended operating and maintenance procedures, maintaining good fuel mixing, and limiting the amount of excess air in the combustion chamber to maximize thermal efficiency.
- Energy efficient design will incorporate insulation to retain heat within the boiler.
- The auxiliary boiler will be limited to 876 hours of operation a year.

Use of these practices corresponds with a permit limit of 7,687 tpy CO_2e for the auxiliary boiler. Compliance will be determined by the number of hours of operation and the calculated emissions using Equation C-1 from 40 CFR Part 98, Subpart C, which is based on metered fuel usage and the emission factor for natural gas.

XI. Emergency Engines (EPNs: EMGEN1-STK and FWP1-STK)

Pinecrest will be equipped with one nominally rated 1,072-hp diesel-fired emergency generator to provide electricity to the facility in the case of power failure and one nominally rated 500-hp diesel-fired pump to provide water in the event of a fire.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Fuels* – Engine options includes engines powered by electricity, natural gas, or liquid fuel, such as diesel, gasoline or fuel oil.
- *Good Combustion Practices and Maintenance* – Good combustion practices include appropriate maintenance of equipment, such as periodic readiness testing, and operating within the recommended air to fuel ratio recommended by the manufacturer.
- *Low Annual Capacity Factor* – Limiting the hours of operation reduces the emissions produced. Each emergency engine will be limited to 100 hours of operation per year for purposes of maintenance checks and readiness testing.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Low Carbon Fuels* – 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. Electricity and natural gas may not be available during an emergency and therefore cannot be used as an energy source for the emergency engines and are eliminated as technically infeasible for this facility. 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. Gasoline fuel has a much higher volatility than diesel, and is thus less safe for use in an emergency situation, and it cannot be stored for long periods of time, which may be necessary for emergency use. Therefore, gasoline is eliminated as infeasible for these emergency engines.
- *Good Combustion Practices and Maintenance* – Is considered technically feasible
- *Low Annual Capacity Factor* – Is considered technically feasible since the engines will only be operated either for readiness testing or for actual emergencies.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Since the remaining technically feasible processes, practices, and designs in Step 1 are being proposed for the engines, a ranking of the control technologies is not necessary.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Since the remaining technically feasible processes, practices, and designs in Step 1 are being proposed for the engines, an evaluation of the most effective controls is not necessary.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the diesel-fired emergency generators:

- *Good Combustion Practices and Maintenance* – Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air to fuel ratio, as specified by its design.
- *Low Annual Capacity Factor* – The emergency engines will not be operated more than 100 hours per year each. They will only be operated for maintenance and readiness testing, and in actual emergency operation.

Using the BACT practices identified above results in a BACT limit of 64 tpy CO_2e for the Emergency Generator (EPN: EMGEN1-STK) and 28 tpy CO_2e for the Fire Water Pump (EPN: FWP1-STK). Pinecrest will demonstrate compliance with the CO_2 emission limit using the default emission factor and default high heating value for diesel fuel from 40 CFR Part 98, Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR § 98.33(a)(3)(iii) is as follows:

$$CO_2 = 1 \times 10^{-3} * Fuel * HHV * EF * 1.$$

Where:
CO_2 = Annual CO_2 mass emissions from combustion of diesel fuel (short tons)
Fuel = Mass or volume of fuel combusted per year, from company records.
HHV = Default high heat value of the fuel, from Table C-1 of 40 CFR Part 98, Subpart C.
EF = Fuel specific default CO_2 emission factor, from Table C-1 of 40 CFR Part 98, Subpart C.
1×10^{-3} = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV).

XII. Natural Gas Fugitive Emissions (EPN: NG-FUG)

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. The additional methane and CO_2 emissions from process fugitives have been estimated to be 510 tpy as CO_2e. Pinecrest will have small amounts of GHGs emitted from gaseous fuel venting during turbine shutdown and maintenance from the fuel lines being cleared of fuel. They will also have small amounts of GHGs emitted from the repair and replacement of small equipment and fugitive components.

Fugitive emissions account for less than 0.02% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Implementing a leak detection and repair (LDAR) program using a handheld analyzer;*
- *Implement alternative monitoring using a remote sensing technology such as infrared camera monitoring; and*
- *Implementing an auditory/visual/olfactory (AVO) monitoring program.*

Step 2 – Elimination of Technically Infeasible Alternatives

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

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Instrument LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[6] The most stringent LDAR program potentially applicable to this facility is TCEQ's 28LAER, which provides for 97% control credit for valves, flanges, and connectors.

As-observed audio, visual, and olfactory (AVO) observation methods are generally somewhat less effective than instrument LDAR and remote sensing, since they are not conducted at specific intervals. However, since pipeline natural gas is odorized with very small quantities of mercaptan, as-observed olfactory observation is a very effective method for identifying and correcting leaks in natural gas systems. Due to the pressure and other physical properties of plant fuel gas, as-observed audio and visual observations of potential fugitive leaks are likewise moderately effective.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Although instrument LDAR and/or remote sensing of piping fugitive emissions in natural gas service may be somewhat more effective than as-observed AVO methods, the incremental GHG emissions controlled by implementation of the TCEQ 28LAER LDAR program or a comparable remote sensing program is less than 0.02% of the total project's proposed CO_2e emissions. Accordingly, given the costs of implementing 28LAER or a comparable remote sensing program when not otherwise required, these methods are not economically practicable for GHG control from components in natural gas service.

[6] 73 FR 78199-78219, December 22, 2008.

Step 5 – Selection of BACT

Based on the economic impracticability of instrument monitoring and remote sensing for natural gas piping components, Pinecrest proposes to incorporate as-observed AVO as BACT for the piping components in the new combined-cycle power plant in natural gas service. The proposed permit contains a condition to implement AVO inspections on a daily basis.

XIII. SF_6 Insulated Electrical Equipment (EPN: SF6-FUG)

The generator circuit breakers associated with the proposed units will be insulated with SF_6. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 400 lbs of SF_6.

Step 1 – Identification of Potential Control Technologies for GHGs

Circuit Breaker Design Efficiency - In comparison to older SF_6 circuit breakers, modern circuit 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 one pound of the SF_6 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.

Alternative Dielectric Material – Because SF_6 has a high GWP, 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*.[7] The alternatives considered include mixtures of SF_6 and nitrogen, gases and mixtures and potential gases for which little experimental data are available.

Step 2 – Elimination of Technically Infeasible Alternatives

Circuit Breaker Design Efficiency – Considered technically feasible and is carried forward for Step 3 analysis.

Alternative Dielectric Material - According to the report NIST Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and

[7] 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. Available at http://www.epa.gov/electricpower-sf6/documents/new_report_final.pdf

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 the use of SF_6.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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 feasible for this application.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Because the only remaining control option is circuit breaker design efficiency, and because that option is selected as BACT, a Step 4 evaluation is not necessary.

Step 5 – Selection of BACT

Circuit breaker design efficiency is selected as BACT. Specifically, state-of-the-art, enclosed-pressure SF_6 circuit breakers with leak detection is the BACT control technology option. The circuit breakers will be designed to meet the latest American National Standards Institute (ANSI) C37.06 and C37.010 standards for high voltage circuit breakers.[8] 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 the lack of "quenching and cooling" SF_6 gas.

BACT compliance will be demonstrated by Pinecrest through annual monitoring of emissions in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmissions and Distribution Equipment Use.[9] Annual SF6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

XIV. Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. § 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed

[8] ANSI Standard C37.06, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current Basis and ANSI Standard C37.010, Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis.*
[9] See 40 CFR Part 98, Subpart DD.

endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) dated May 1, 2014, prepared by the applicant, Pinecrest Energy Center, LLC ("Pinecrest"), and its consultant, Zephyr Environmental Corporation ("Zephyr"), and reviewed and adopted by EPA.

A draft BA has identified four (4) species listed as federally endangered or threatened in Angelina County, Texas:

Federally Listed Species for Angelina County by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Red cockaded woodpecker	*Picoides borealis*
Piper Plover	*Charadrius melodus*
Mammals	
Louisiana black bear	*Ursus americanus luteolus*
Red Wolf	*Canis rufus*

EPA has determined that issuance of the proposed permit will have no effect on any of the four listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

Because of EPA's "no effect" determination, no further consultation with the USFWS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XV. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by Horizon Environmental Services, Inc. (Horizon) on behalf of Zephyr Environmental Corporation, Inc. ("Zephyr"), for Pinecrest Energy Center, LLC ("Pinecrest"), submitted in May 1, 2014.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be the 77-acre tract containing the construction footprint of the project plus approximately 24 acres composed of two miles of associated pipeline and 100-foot right-of-way, for a total project size of 101 acres. Horizon conducted a field survey, including shovel testing, of the APE and a desktop review within a 1.0-mile radius area of potential effect (APE). The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP).

Based on the result of the desktop review, seven cultural resource surveys have previously been done within a mile of the APE, ten (10) archaeological sites are identified within a one-mile radius of the APE; however they are outside the APE. One previously recorded archaeological site was identified within the APE; however, it was recommended to be ineligible for listing on the National Register of Historic Places. Based on the results of the field survey no other historic or cultural resources were identified within the APE.

Based upon the information provided in the cultural resources report, EPA Region 6 determines that because no historic properties are located within the APE of the facility site and potential for the location of archaeological resources eligible for listing on the National Register is low within the construction footprint itself, issuance of the permit to Pinecrest will not affect properties on or potentially eligible for listing on the National Register.

On March 25, 2014, EPA sent letters to twenty-six (26) Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit.

EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVI. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass,* Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are 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 [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XVII. Conclusion and Proposed Action

Based on the information supplied by Pinecrest, our review of the analyses contained the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue Pinecrest a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

Appendix A

Annual Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month, rolling total, shall not exceed the following if the General Electric 7FA.05 is selected as the combustion turbine model:

Table 1A. Annual Emission Limits[1] - General Electric 7FA.05

FIN	EPN	Description[2]	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
CTG1/HRSG1	U1-STK	Combined-cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,446,186	1,447,653	942.0 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. Startup emissions limited to 500 hours per year and 83 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	26.8		
			N_2O	2.7		
CTG2/HRSG2	U2-STK	Combined-cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,446,186	1,447,653	942.0 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. Startup emissions limited to 500 hours per year and 83 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	26.8		
			N_2O	2.7		
AUXBLR	AUXBLR	Auxiliary Boiler	CO_2	7,680	7,687	Good Combustion and Operating Practices. Limit to 876 hours of operation per year. See Special Conditions III.B.
			CH_4	0.14		
			N_2O	0.01		
EMGEN1	EMGEN1-STK	Emergency Generator	CO_2	64	64	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
FWP1	FWP1-STK	Fire Water Pump	CO_2	28	28	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		

FIN	EPN	Description	GHG Mass Basis		TPY CO e[2,3]	BACT Requirements
				TPY[2]		
NG-FUG	NG-FUG	Natural Gas Fugitives [6,8]	CO_2	0.8	510	Implementation of AVO Monitoring. See Special Condition III.D.
			CH_4	20.4		
SF6-FUG	SF6-FUG	SF_6 Insulated Equipment[6]	SF_6	No Numerical Limit Established[6]	23	Instrumented monitoring and alarm. See Special condition III.D.
Totals[7]			**CO_2**	**2,900,145**	**2,903,627**	
			CH_4	**74**		
			N_2O	**5.4**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling total.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298, SF_6 = 22,800
4. The annual emissions limit for the combustion turbines is based on operating at maximum duct burner firing for 8,260 hours per year, and operating during startup, shutdown, and maintenance (MSS) for 500 hours per year. The annual emission limit includes emissions from MSS.
5. The lb/MWh BACT limit for the combustion turbine does not apply during startup.
6. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. Total emissions are for information only and do not constitute an emission limit.
8. EPN NG-FUG includes fugitive emissions from piping and other components, as well as emissions from gaseous fuel line purging and maintenance/repair/replacement of fugitive components.

Annual emissions, in tons per year (TPY) on a 12-month, rolling total, shall not exceed the following if the Siemens SGT6-5000F(4) is selected as the combustion turbine model:

Table 1B. Annual Emission Limits[1] - Siemens SGT6-5000F(4)

FIN	EPN	Description[2]	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
CTG1/HRSG1	U1-STK	Combined-cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,398,427	1,399,842	909.2 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. Startup emissions limited to 500 hours per year and 84 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	25.9		
			N_2O	2.6		
CTG2/HRSG2	U2-STK	Combined-cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,398,427	1,399,842	909.2 lb CO_2/MWh (gross) with duct burning.[5] See Special Conditions III.A.1. Startup emissions limited to 500 hours per year and 84 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	25.9		
			N_2O	2.6		
AUXBLR	AUXBLR	Auxiliary Boiler	CO_2	7,680	7,687	Good Combustion and Operating Practices. Limit to 876 hours of operation per year. See Special Conditions III.B.
			CH_4	0.14		
			N_2O	0.01		
EMGEN1	EMGEN1-STK	Emergency Generator	CO_2	64	64	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
FWP1	FWP1-STK	Fire Water Pump	CO_2	28	28	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
NG-FUG	NG-FUG	Natural Gas Fugitives[6]	CO_2	0.8	510	Implementation of AVO Monitoring. See Special Condition III.D.
			CH_4	20.38		

FIN	EPN	Description[2]	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
SF6-FUG	SF6-FUG	SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[6]	23	Instrumented monitoring and alarm. See Special condition III.D.
Totals[7]			**CO_2**	**2,804,627**	**2,808,007**	
			CH_4	**72.3**		
			N_2O	**5.2**		

1. Compliance with the annual emission limits (tons per year) is based on a 12 month rolling total.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298, SF_6 = 22,800
4. The annual emissions limit for the combustion turbines is based on operating at maximum duct burner firing for 8,260 hours per year, and operating during startup, shutdown, and maintenance (MSS) for 500 hours per year. The annual emission limit includes emissions from MSS.
5. The lb/MWh BACT limit for the combustion turbine does not apply during startup.
6. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. Total emissions are for information only and do not constitute an emission limit.
8. EPN NG-FUG includes fugitive emissions from piping and other components, as well as emissions from gaseous fuel line purging and maintenance/repair/replacement of fugitive components.

Annual emissions, in tons per year (TPY) on a 12-month, rolling total, shall not exceed the following if the Siemens SGT6-5000F(5) is selected as the combustion turbine model:

Table 1C. Annual Emission Limits[1] - Siemens SGT6-5000F(5)

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
U1-STK	U1-STK	Combined-cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,569,269	1,570,854	912.7 lb CO_2/MWh (gross) with duct burning.[5] See Special Condition III.A.1. Startup emissions limited to 500 hours per year and 85 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	29		
			N_2O	2.9		
U2-STK	U2-STK	Combined-cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,569,269	1,570,854	912.7 lb CO_2/MWh (gross) with duct burning.[5] See Special Conditions III.A.1. Startup emissions limited to 500 hours per year and 85 tons CO_2/hr. See Special Conditions III.A.1. and III.A.4.e.
			CH_4	29		
			N_2O	2.9		
AUXBLR	AUXBLR	Auxiliary Boiler	CO_2	7,680	7,687	Good Combustion and Operating Practices. Limit to 876 hours of operation per year. See Special Conditions III.B.
			CH_4	0.14		
			N_2O	0.01		
EMGEN1	EMGEN1-STK	Emergency Generator	CO_2	64	64	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
FWP1	FWP1-STK	Fire Water Pump	CO_2	28	28	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions III.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
NG-FUG	NG-FUG	Natural Gas Fugitives[6,8]	CO_2	0.8	510	Implementation of AVO Monitoring. See Special Condition III.D.
			CH_4	20.4		

FIN	EPN	Description	GHG Mass Basis		TPY CO e[2,3]	BACT Requirements
			TPY[2]			
SF6-FUG	SF6-FUG	SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[6]	23	Instrumented monitoring and alarm. See Special condition III.D.
Totals[7]			**CO_2**	**3,146,311**	**3,150,030**	
			CH_4	**78.7**		
			N_2O	**5.8**		

1. Compliance with the annual emission limits (tons per year) is based on a 12 month rolling total.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298, SF_6 = 22,800
4. The annual emissions limit for the combustion turbines is based on operating at maximum duct burner firing for 8,260 hours per year, and operating during startup, shutdown, and maintenance (MSS) for 500 hours per year. The annual emission limit includes emissions from MSS.
5. The lb/MWh BACT limit for the combustion turbine does not apply during startup.
6. All values indicated as “No Numerical Limit Established” are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. Total emissions are for information only and do not constitute an emission limit.
8. EPN NG-FUG includes fugitive emissions from piping and other components, as well as emissions from gaseous fuel line purging and maintenance/repair/replacement of fugitive components.