Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the City of Austin dba Austin Energy, Sand Hill Energy Center

Permit Number: PSD-TX-1012-GHG

July 2014

This document serves as the Statement of Basis (SOB) 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 September 13, 2013, the City of Austin dba Austin Energy (Austin Energy), submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project. The project will construct an additional natural gas-fired combined-cycle electric-generating unit at the existing Sand Hill Energy Center (SHEC), located in Del Valle, Travis County, Texas. On October 18, 2013, January 28, 2014 and April 11, 2014, Austin Energy submitted additional information for inclusion into the application. In connection with the same proposed construction project, Austin Energy submitted an application for a PSD permit for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on September 12, 2013. 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 SHEC.

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

EPA Region 6 concludes that Austin Energy'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 provided by Austin Energy at EPA's request, 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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III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan (FIP) that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. See 75 FR 25178 (promulgating 40 CFR § 52.2305).

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:
Tracie Donaldson
Air Permitting Section (6PD-R)
(214) 665-6633

IV. Facility Location

The SHEC is located at 1101 Fallwell Lane, along the Colorado River, approximately one mile north-northeast (NNE) of the Highway 130 and 71 intersection in Travis County, Texas. This area is currently designated "attainment" for all criteria pollutants. The nearest Class 1 area is the Big Bend National Park, which is located over 450 miles from the site. The geographic coordinates for this proposed facility site are as follows:

Latitude: 30º 12' 28"
Longitude: 97º 36'53"

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

Figure 1. Sand Hill Energy Center Location

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

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. On June 23, 2014, the United States Supreme Court issued a decision addressing the application of stationary source permitting requirements to greenhouse gases (GHG). *Utility Air Regulatory Group (UARG) v. Environmental Protection Agency* (EPA) (No. 12-1146). The Supreme Court said that the EPA may not treat greenhouse gases as an air pollutant for purposes of determining whether a source is a major source required to obtain a Prevention of Significant Deterioration (PSD) or title V permit. However, Court also said that the EPA could continue to require that PSD permits, otherwise required based on emissions of conventional pollutants, contain limitations on GHG emissions based on the application of Best Available Control Technology (BACT). Pending further EPA engagement in the ongoing judicial process before the District of Columbia Circuit Court of Appeals, the EPA is proposing to issue this permit consistent with EPA's understanding of the Court's decision.

The source is a major source because the facility has the potential to emit 155 tpy of NOx, 651 tpy of CO, 85 tpy VOC, 84 tpy of PM_{10} and 85 tpy of $PM_{2.5}$. In this case, the applicant represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will determine the project is subject to PSD review for the following conventional regulated NSR pollutants: NOx, CO, VOC, PM_{10} and $PM_{2.5}$.

The applicant also estimates that this same project will result in a GHG emissions increase and a net GHG emissions increase of 1,462,052 tpy CO_2e and is greater than zero tons per year mass basis, which well exceeds the GHG thresholds in EPA regulations. 40 C.F.R §(49)(iv); see also, *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) at 12-13). Since the Supreme Court recognized EPA's authority to limit application of BACT to sources that emit GHGs in greater than *de minimis* amounts, EPA believes it may apply the 75,000 tons per year threshold in existing regulations at this time to determine whether BACT applies to GHGs at this facility.

Accordingly, this project continues to require a PSD permit that includes limitations on GHG emissions based on application of BACT. The Supreme Court's decision does not materially limit the FIP authority and responsibility of Region 6 with regard to this particular permitting action. Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[1]

EPA Region 6 proposes to follow the policies and practices reflected in EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011). For the reasons described in that guidance, we have not 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 believes that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional

[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

impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has regulated NSR pollutants that are non-GHG pollutants, which are addressed by the PSD permit to be issued by TCEQ.

VI. Project Description

The proposed GHG PSD permit, if finalized, would authorize Austin Energy to construct an additional combined cycle unit at the SHEC in Travis County, Texas. The existing SHEC is a natural gas-fired combined-cycle base-load power generating station that currently operates in a 1 by 1 by 1 (1 x 1 x 1) configuration with a combustion turbine, heat recovery steam generator (HRSG) equipped with duct burners, and a steam turbine. The proposed modification includes a new combustion turbine (GE.7FA.04) and new HRSG equipped with duct burners. The resulting new facility will be a natural gas-fired combined-cycle power generating station in a 2 by 2 by 1 (2 x 2 x 1) configuration that utilizes the existing combustion turbine and HRSG, the new combustion turbine and HRSG, and the existing non-modified steam turbine.[2] The SHEC retains the ability to operate the facility in either a 1 x 1 x 1 combined-cycle configuration or in a 2 x 2 x 1 combined-cycle configuration.[3]

The new units at the SHEC (along with the increased output from the existing steam turbine) will generate an additional 222 megawatts (MW) of gross electrical power near the City of Austin. The gross electrical power output is based on a combustion turbine rated at 187 MW at ISO conditions and the steam from the HRSG driving the existing steam turbine at an increased output capacity of approximately 32 MW. The SHEC will consist of the following new sources of GHG emissions:

- One natural gas-fired combustion turbine;
- One HRSG equipped with natural gas-fired duct burners; and
- Electrical equipment insulated with sulfur hexafluoride (SF_6).

Combustion Turbine

The proposed modifications will consist of one natural gas-fired combustion turbine generator, the General Electric 7FA.04. The combustion turbine will exhaust to a HRSG equipped with duct burners.

The combustion turbine will burn pipeline natural gas to rotate an electrical generator to generate electricity. The main components of a combustion turbine are a compressor, a combustor, and a

[2] A process flow diagram of the proposed combined cycle unit is provided on page 2-6 of the application. Available at http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/austin-energy-sandhill-app.pdf
[3] A detailed process flow diagram for the existing and proposed combined cycle units is provided on page 2-6 of the application. Available at http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/austin-energy-sandhill-app.pdf

turbine. The turbine will be coupled to a 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.

HRSG with Duct Burners

Heat recovered in the HRSG will be utilized to produce steam. Steam generated within the HRSG will drive a steam turbine and its 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 681.5 MMBtu/hr per unit. The exhaust gases from the unit, including emissions from the combustion turbine and the duct burners, will exit through a stack to the atmosphere.

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 (SCR) system.

Inlet Air Cooling

The inlet air to the new and existing combustion turbines will be cooled during high ambient temperature conditions through the use of chillers or evaporative coolers. Cooling of the inlet air will increase output of the combustion turbines while lowering their heat rates.

Generation Capacity Overall

Depending on the operational configuration, steam produced by the new and/or existing HRSGs will be routed to the existing steam turbine. The new and existing combustion turbines and the existing steam turbine will be coupled to electric generators to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid. The proposed combustion turbine has an approximate maximum base-load electric power output of 187 MW at ISO conditions. The maximum electric power output from the steam turbine is approximately 189 MW. The units may operate at reduced load to respond to changes in system power requirements and/or stability.

Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

The generator circuit breakers associated with the proposed units will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, and non-toxic synthetic 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 that under normal circumstances do not leak gas. The capacity of the circuit breakers associated with the proposed unit is currently estimated to be 59 lbs of SF_6. The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. The alarm will alert personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of "quenching and cooling" of 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 turbine). The project will have fugitive emissions from piping components which will account for 141.2 TPY of CO_2e, or less than 0.01% of the project's total CO_2e emissions. 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 Turbine (SH8)
- Natural Gas Fugitives (MS-FUG and PB-FUG)
- SF_6 Insulated Equipment (SF6-FUG)

IX. Combined-Cycle Combustion Turbine and HRSG (EPN: SH8)

There will be one new natural gas-fired combined-cycle combustion turbine used for power generation. Austin Energy is evaluating one combustion turbine for this project: the General Electric 7FA. The BACT analysis for the turbine 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 (CCS).

As part the permit application, Austin Energy provided a five-step top-down BACT analysis for the combustion turbines. EPA has reviewed Austin Energy's BACT analysis for the combustion turbine, which is part of the record for this permit (including this SOB). We also provide our own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identify All Available Control Options

(1) **Energy Efficiency Processes, Practices, and Design**

Combustion Turbine:

- *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 turbine model under consideration for the SHEC facility is a highly efficient turbine, in terms of the 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.
- *Instrumentation and Controls*– Austin Energy proposes to incorporate automatic Dry Low NO_x (DLN) tuning into the control system. The automatic tuning will include tracking and modulating to optimize heat rate and emissions in real time.

HRSG:

- *Heat Exchanger Design Considerations* – The HRSG is 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 on an as-needed basis. 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 de-aerator vents, blow-down 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 blankets the heat transfer surfaces

lowering the equipment's performance. Steam leaks are repaired as soon as possible to maintain facility performance.

Other Plant-wide Energy Efficiency Features

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

- *Use of Low Carbon Fuel* – Natural gas is the lowest carbon fossil fuel that exists. Fuel gases that contain significant amounts of hydrogen and that produce no CO_2 when burned, can be burned in turbines and duct burners if available. Use of fuel gas is an effective means of reducing GHG emissions in such situations.
- *Inlet Fuel Gas Preheating* – The overall efficiency of the combustion turbine is increased with inlet fuel preheating.
- *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 for operation. 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.

(2) **Carbon Capture and Storage (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)."[4]

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

[4] 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.

heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for combustion-turbine applications and still requires the development of oxyfuel 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 natural-gas combined-cycle facility. The third approach, post-combustion capture, is an available option for combustion turbines.

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 combustion-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 base load 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.[5]

Step 2 – Elimination of Technically Infeasible Alternatives

Austin Energy's application examines the technical feasibility of CCS for this project and concludes that:

> Amine absorption technology for the capture of CO_2 has been applied to natural gas–fired processes in the petroleum industry and natural gas processing industry, and therefore it is technically feasible to apply the technology to that of power plant turbine exhaust streams. However, the technologies have not been proven to be reliable, nor are they ready for full-scale commercial deployment. Although numerous research pilot-scale projects for high-volume carbon sequestration are underway, these projects are still a few years from implementation. Furthermore, although a single natural gas–fired combined cycle combustion turbine project with CO_2 capture capabilities has been issued a standard permit by the TCEQ, this project has yet to be constructed. Although Austin Energy questions whether it is feasible to implement CCS on a full-scale natural gas-fired combustion turbine project, an economic feasibility analysis for implementing CCS for control of the CO_2 emissions from the combustion turbine is discussed in detail in Step 4 of this section.

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 CCS is technically feasible for the NGCC source category, 79 Fed. Reg. at 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. In addition, the other control options identified in Step 1 are considered technically feasible for this project.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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[5] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

Energy efficiency processes, practices, and designs are all considered effective and have a range of efficiency improvements which 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) reduction 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

Carbon Capture and Storage

Austin Energy developed a cost analysis for CCS that estimated the capital cost of a CO_2 capture system for the SHEC at approximately $170 million[6]. The capital cost components include equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management and contingencies.

Denbury Resources (Denbury) operates a CO_2 pipeline in southeast Texas, called the "Green Pipeline". The nearest location for delivery to the Green Pipeline is in the Hastings oil field southeast of Houston. The distance to the Hastings oil field is 135 miles. In order to get CO_2 from the SHEC to the Green Pipeline, Austin Energy would have to construct a 135 mile pipeline. The estimated capital cost for such a pipeline was estimated to be $238 million. The closest site that is currently being field-tested to demonstrate its capacity for large-scale geological storage of CO_2 is the Southwest Regional Partnership on Carbon Sequestration's (SWP) SACROC test site, located in Scurry County, Texas, approximately 240 miles away. A high pressure pipeline would need to be constructed to this site to transport the CO_2 which would potentially cost more than transport to Denbury's Green Pipeline.

Based on an estimated capital cost of the project to add a combustion turbine and HRSG of $195 million, the addition of the CO_2 capture portion of CCS as an add-on pollution control and the construction of a pipeline for EOR purposes are estimated to increase the capital cost by over 200%. Austin Energy maintains that such a large increase in project cost renders CCS economically infeasible. EPA has reviewed Austin Energy's estimated CCS cost projections and believes the estimated cost projections are credible. Accordingly, we conclude that CCS would render the project economically infeasible for Austin Energy, and we are eliminating CCS as a BACT option for this facility.

Energy Efficiency Processes, Practices and Design

There are no known adverse economic, energy, or environmental impacts associated with the various control technologies identified in Step 1 for energy efficiency process, practices, and

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

design. All these options are proposed for the facility. An additional discussion of the turbine-model selection process is provided below for information purposes;

Combustion Turbine Design – In a combined-cycle configuration, a HRSG is used to recover what would otherwise be waste heat lost to the atmosphere in the hot turbine exhaust. Use of heat recovery from the turbine exhaust to produce steam to power a steam turbine that generates additional electric power is the single most effective means of increasing the efficiency of combustion turbines used for electric power generation. The overall thermal efficiency for the proposed project is increased from about 39% for a simple-cycle configuration (no heat recovery) to about 59% for a combined-cycle configuration, which includes electricity generated by the steam turbine. In applications where process heat is needed, the steam produced in the HRSG can also be used to provide heat to plant processes in addition to or instead of being used to produce additional electricity. This "cogeneration" technology is not applicable to electric power generation unless there is a co-located steam host or other means of using additional recoverable waste heat.

The existing 164 MW (nominal at ISO) GE 7FA.03 combined-cycle combustion turbine at the SHEC is operating in a 1 x 1 x 1 configuration with a HRSG and a 189 MW GE D−11 steam turbine. Even with duct burners firing at maximum design capacity, the full 189 MW capacity of the steam turbine cannot be utilized with only the existing combustion turbine and HRSG. Consequently, expansion to a 2 x 1 x 1 configuration was anticipated as part of the original facility design. The existing steam turbine and cooling tower were sized for a second combustion turbine and associated HRSG.

Installing a second GE7FA combustion turbine provides benefits from an operations and maintenance perspective that other turbine models would not. The SHEC plant staff are experienced in operating and maintaining the GE7FA, so the addition of a second GE 7FA would minimize changes to the control system, operating procedures and training. A second GE7FA would also simplify maintenance by leveraging staff experience as well as reduce the quantity and cost of spare parts that would be required to maintain two different combustion turbine models.

The estimated cost savings associated with the selection of a second GE 7FA combustion turbine versus a different turbine model are:

- Operation training: $300,000
- Control system integration: $3,000,000 (exclusive of engineering and design changes and commissioning complications)
- Spare combustion parts: $3,000,000 to $5,000,000
- Long Term Service Agreement (LTSA): $3,000,000 to $4,000,000 (incremental)

Newer versions of the GE 7FA turbine are now available that allow for a higher firing temperature and corresponding improvements in output and heat rate (i.e., greater thermal efficiency). The output of the existing GE 7FA.03 combustion turbine at the SHEC is 161.5 MW at full load at the site ambient average temperature of 68°F. The newer GE 7FA.04 has an output of 187 MW at the same conditions. The newer still GE 7FA.05 demonstrates even greater efficiency, but was not chosen due to physical constraints posed by the existing steam turbine. The existing steam turbine is sized for two GE 7FA.03 combustion turbines operating with two HRSGs. The GE 7FA.05 is significantly larger than the GE 7FA.03 and would produce more steam in the associated HRSG than the existing steam turbine could handle. Therefore, installing a GE 7FA.05 combustion turbine would result in the generation of excess steam that would either have to be condensed or vented, leading to an overall loss of efficiency.

These same technical challenges are not present with the smaller GE 7FA.04. Thus, while there would be advantages to installing a second GE 7FA.03 combustion turbine at the facility, the improved performance, greater efficiency, and reduced GHG emissions per MWh of electricity generated associated with the GE 7FA.04 prompted its selection by the SHEC.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the turbine:

- Use of Combined Cycle Power Generation Technology
- Combustion Turbine Energy Efficiency Processes, Practices, and Design
    - Highly Efficient Turbine Design
    - Periodic Turbine Burner Tuning
    - 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
- Plant-wide Energy Efficiency Processes, Practices, and Design
    - Use of low carbon fuel
    - Fuel Gas Preheating
    - Drain Operation
    - Multiple Combustion Turbine/HRSG Trains

BACT Limits and Compliance:

Proposed BACT for this project is the preceding energy efficiency processes, practices, and designs for the proposed combined-cycle combustion turbine.

The proposed GE 7FA.04 combustion turbine is the most efficient unit available that is suitable for incorporation into the existing combined-cycle unit, as described above, with a gross heat rate at base load ranging from 9,744 to 10,639 Btu/kWh, HHV, without evaporative cooling, depending on ambient conditions (refer to Table 5−3 from the application). For comparison, the existing GE 7FA.03 combustion turbine has a heat rate ranging from 10,004 to 11,055 Btu/kWh, HHV, across the same range of conditions. Thus, the newer model is about 3 to 4% more efficient, translating to 3 to 4% lower GHG emissions. In combined-cycle mode, with the benefit of the HRSG and additional output from the steam turbine, the gross heat rate of the proposed GE 7FA.04 combustion turbine is expected to range from 7,044 to 7,833 Btu/kWh, HHV without evaporative cooling.

Combustion Turbine BACT Emission Limits

Table 2. BACT Emission Limits for Combustion Turbines on a 365-day rolling average

Turbine Model	Gross Heat Rate, with duct burner firing (Btu/kWh) (HHV)[1]	Output-Based Emission Limit (lbs CO_2/MWh) gross with duct burning[1]
General Electric 7FA.04	7,943	930

[1] These limits apply with and without duct burner firing and includes startup and shutdown.

The proposed output−based GHG emission limits are equivalent to the most recent GHG permit limits for similar combined-cycle units as summarized in the table below (approximately 0.465 ton CO_2/MWh or 930 lb/MWh, combined-cycle basis) and the proposed heat rate limit is comparable to the most recent limits for similar units.

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

- 2.0% added for variations between as built and design conditions (design margins), including periods of operation at part load conditions,
- 5.0% for efficiency loss due to equipment degradation (performance margin), and
- 3.0% for variations in operation of ancillary plant facilities (degradation margin)

Design Margin - 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. Typically, the market for contracting the engineering design and construction of combined cycle power plants has a design margin of 5% for the guaranteed net MW output and net heat rate. This is the condition for which the contractor has a "make right" obligation to continue tuning the facility's performance to achieve this minimum value. Therefore, the contractor must deliver a facility that is capable of generating 95% of the guaranteed MW and must have a heat rate that is no more than 105% of the guaranteed heat rate.

Performance Margin on Combustion Turbine and Steam Turbine Generators - The performance margin for equipment degradation relates to the combustion turbine and steam turbine generators. 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 project 5% degradation rate represents the average, and not the maximum or guaranteed, rate of degradation for the gas turbine. A 20-year degradation of 5% is used. This degradation rate is comparable to the rates estimated by other natural gas fired power plants that have received a GHG PSD permit.

Degradation Margin for the Auxiliary Plant Equipment - The degradation margin for the auxiliary plant equipment encompasses the HRSGs. This margin accounts for the scaling and corrosion of the boiler tubes over time, as well as minor potential fouling of the heating surface of the tubes. Similar to the HRSGs, scaling and corrosion of the condenser tubes will also degrade the heat transfer characteristics, thus degrading the performance of the steam turbine generator. Because combustion turbine degradation accounts for the majority of the performance loss, as well as the large variation in operating parameters (fuels, temperatures, water treatment, cycling conditions, etc.), little operating data has been gathered and published that illustrate a clear performance degradation characteristic for this auxiliary plant equipment. This degradation rate is comparable to the rates estimated by other natural gas fired power plants that have received a GHG PSD permit.

Because the plant heat rate varies according to turbine operating load and amount of duct burner firing, Austin Energy will demonstrate compliance with the proposed heat rate with an annual compliance test at 90% load, corrected to ISO conditions. Each of the proposed limits is calculated to include a 10% margin to account for measurement error, equipment and site variations, and degradation over time.

The proposed GHG BACT limits for the proposed new unit are summarized in the table below.

Form of Limit	Limit	Averaging Period	Basis
Out-put Based GHG Limit	930 lbs CO_2/MWh	365-day rolling average	Combined cycle-combustion turbine only, gross output basis (1x1x1)
Heat Rate Limit	7,943 Btu/kWh (HHV)	365-day rolling average	Combined-cycle combustion turbine only, gross output basis
Annual GHG Emission Limit	1,462,052 tons CO_2e/year	365-day rolling average	Includes all stack emissions from combustion turbine, duct burners, start-ups, shutdowns, malfunctions

			and effects of different operating conditions including evaporative inlet air cooling

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	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
Kennecott Utah Copper-Repowering South Jordan, UT	275 MW Combined-cycle	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	Energy Efficiency/ Good Design & Combustion Practices	825 lbs CO_2e/MWh_{grid} (initial performance test) 895 lbs 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 Combined-cycle with Duct Burner	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 Combined-cycle with Duct Burner	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	637-735 MW depending on turbine model selected Combined-cycle	Energy Efficiency Good Design & Combustion Practices	Annual Heat Input - 7,679 Btu/kWh 934-909 lb CO_2/MWh depending on turbine model selected	2013	PSD-TX-1288-GHG
Pinecrest Energy Center Lufkin, TX	637-735 MW depending on turbine model selected	Energy Efficiency Good Design & Combustion Practices	909.2-942.0 lb CO2/MWh depending on turbine model selected	2014	PSD-TX-1298-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
	Combined-cycle with Duct Burner				

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 New Stationary Sources: Electric Utility Generating Units, 77 FR 22392) that would control CO_2 emissions from new electric generating units (EGUs). The proposed rule would apply to fossil fuel fired EGUs that generate electricity for sale and are larger than 25 MW. EPA proposed that large, natural gas combined cycle EGUs must meet an annual average output-based standard of 1,000 lb CO_2/MWh, on a gross basis. In a 1 x 1 x 1 configuration, the proposed facility with the existing steam turbine would generate 331 MW. The proposed emission rate for the SHEC combustion turbine, on a gross electrical output basis, is 930 lb CO_2/MWh, with or without duct burner firing. The proposed CO_2 emission rate for the SHEC combustion turbine is therefore less than the emission limit proposed in the NSPS at 40 CFR Part 60 Subpart TTTT.

Austin Energy will demonstrate compliance with the CO_2 limit established as BACT by calculating the CO_2 value based on equation G-4 of 40 CFR 75, Appendix G. The calculated CO_2 emission value is divided by the summed amount of the combustion turbine's gross output and the apportioned steam turbine's gross output (MW). The resulting quotient is then converted to lb CO_2/MWh and compared to the BACT limit of 930 lb CO_2/MWhr on a 365-day rolling basis. To determine the apportioned steam turbine gross output, a plan shall be submitted to demonstrate the apportionment of the gross electric output within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days from the date of initial startup of the combustion turbine. This plan will detail how the apportionment will be determined, and a monitoring strategy to demonstrate the apportionment will be included.

As an alternative to calculating emissions under equation G-4, Austin Energy may choose to install and operate a CO_2 continuous emission monitoring system (CEMS) to determine the amount of CO_2 from combustion. If the CO_2 CEMS is selected, the measured hourly CO_2 emissions are divided by the gross hourly energy output and averaged daily. For any period of time that the CO_2 CEMS is nonfunctional, Austin Energy shall use the methods and procedures outlined in the Missing Data Substitution Procedures as specified in 40 CFR Part 75, Subpart D.

To determine compliance with the CO_2e annual emission limit, Austin Energy shall calculate the emission values for CO_2, CH_4 and N_2O based on equation G-4 of 40 CFR 75, Appendix G, emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, fuel usage, and the actual heat input (HHV). 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 shall be required to be kept to demonstrate compliance with the emission limits on a 365-day rolling basis.

Austin Energy will 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.

Austin Energy 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 shall meet an accuracy of 2.0% and is required to be tested once each calendar quarter pursuant to 40 CFR Part 75, Appendix D §§ 2.1.5 and 2.1.6(a).
- Gross Calorific Value (GCV) of pipeline natural gas shall be determined at least once per calendar month pursuant to 40 CFR Part 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 Rule for Electricity Generation). The CO_2 monitoring method proposed by Austin Energy is consistent with the recently proposed NSPS, Subpart TTTT (40 CFR 60.5535(c)), which allows for EGUs firing gaseous fuel to determine CO_2 mass emissions by monitoring fuel combusted in the affected EGU and using a site specific Fc factor determined in accordance to 40 CFR Part 75, Appendix F.

An initial stack test demonstration will be required for CO_2 emissions from EPN: SH8. Austin Energy will demonstrate compliance with the proposed heat rate with an initial compliance test at or above 90% load and subsequent annual testing. The conditions of the performance tests shall be conducted under such conditions to ensure representative performance of the affected facility and shall be recorded and made available for review upon request. An initial stack test demonstration will be required for CO_2 emissions from SH8. Austin Energy will demonstrate compliance with the proposed heat rate with an annual compliance test at 90% load, corrected to ISO conditions. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emissions comprise approximately 0.01% of the total CO_2e emissions from the combustion turbines.

X. Natural-Gas Fugitive Emissions (MS-FUG and PB-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 141.2 tpy as CO_2e. The SHEC 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.

Step 1 – Identification of Potential Control Technologies

- Leakless/Sealless Technology
- Instrument Leak Detection and Repair (LDAR) Programs
- Remote Sensing
- Auditory/Visual/ Olfactory (AVO) Monitoring
- Use of High Quality Components and Materials

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Leakless technologies are effective in eliminating fugitive emissions from valve stems and flanges, though there are still some areas where fugitive emissions can occur (e.g., relief valves). Instrument monitoring (LDAR) is effective for identifying leaking components and is an accepted practice by EPA. Quarterly monitoring with an instrument and a leak definition of 500 ppm is assigned as a control effectiveness of 97%. The Texas Commission on Environmental Quality's LDAR program, 28LAER, provides for 97% control credit for valves, flanges, and connectors.
Remote sensing using infrared imaging has proven effective in identifying leaks, especially for components in difficult to monitor areas. LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[7]
AVO monitoring is effective due to the frequency of observation opportunities, but it is not very effective for low leak rates. It is not preferred for identifying large leaks of odorless gases such as methane. However, since pipeline natural gas is odorized with very small quantities of mercaptan, AVO 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, AVO observations of potential fugitive leaks are likewise moderately effective.
The use of high quality components is also effective relative to the use of lower quality components.

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

Although the use of leakless components, instrument LDAR and/or remote sensing of piping fugitive emission in natural gas service may be somewhat more effective than as-observed AVO methods, the incremental GHG emissions controlled by implementation of the TCEQ 28 LAER

[7] 73 FR 78199-78219, December 22, 2008.

LDAR program or a comparable remote sensing program is considered a de minimis level in comparison to the total project's proposed CO_2e emissions. Accordingly, given the costs of implementing 28 LAER 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. Given that GHG fugitives are conservatively estimated to be little more than 2 tons per year CH_4, there is, in any case, a negligible difference in emissions between the considered control alternatives.

Step 5 – Selection of BACT

Due to the very low VOC content of natural gas, the SHEC will not be subject to any VOC leak detection programs by way of its state-PSD permit, TCEQ Chapter 115 – Control of Air Pollution from Volatile Organic Compounds, New Source Performance Standards (40 CFR Part 60), National Emission Standard for Hazardous Air Pollutants (40 CFR Part 61), or National Emission Standard for Hazardous Air Pollutants for Source Categories (40 CFR Part 63). Therefore, any leak detection program implemented will be solely due to potential GHG emissions. Because the uncontrolled CO_2e emissions from the natural gas-piping after implementation of as-observed AVO methods will represent approximately 0.01% of the total site-wide CO_2e emissions, any further emission reduction techniques applied to the piping fugitives will provide minimal CO_2e emission reductions.

Based on the economic impracticability of instrument monitoring and remote sensing for natural gas piping components, EPA 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.

XI. SF_6 Insulated Electrical Equipment (SF_6-FUG)

Step 1 – Identification of Potential Control Technologies for GHGs

In determining whether a technology is available for controlling and reducing SF_6 emissions from circuit breakers, permits, permit applications, and EPA's RACT/BACT/LAER Clearinghouse (RBLC) were consulted. In addition, currently available literature was reviewed to identify emission reduction methods.[8,9,10] Based on these resources, the following available control technologies were identified:

- Use of new and state-of-the-art circuit breakers that are gas-tight and require less SF_6.
- Evaluating alternate substances to SF_6 (e.g., oil or air blast circuit breakers).

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[8] Robert Mueller. *10 Steps to Help Reduce SF6 Emissions in T&D.* Airgas Inc. Available at: http://www.airgas.com/documents/pdf/50170-120.pdf.

[9] U.S. EPA. 2008. *SF6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report.* Available at: http://www.epa.gov/electricpower-sf6/documents/sf6_2007_ann_report.pdf.

[10] J. Blackman (U.S. EPA, Program Manager, SF_6 Emission Reduction Partnership for Electric Power Systems), M. Averyt (ICF Consulting), and Z. Taylor (ICF Consulting). 2006. *SF_6 Leak Rates from High Voltage Circuit Breakers – U.S. EPA Investigates Greenhouse Gas Emissions Source*. Available at: http://www.epa.gov/electricpower-sf6/documents/leakrates_ circuitbreakers.pdf.

- Implementing an LDAR program to identify and repair leaks and leaking equipment as quickly as possible.
- Systematic operations tracking, including cylinder management and SF_6-gas recycling cart use.
- Educating and training employees on proper SF_6 handling methods and maintenance operations.

Step 2 – Elimination of Technically Infeasible Alternatives

Of the control technologies identified above, only substitution of SF_6 with another non-GHG substance is determined as technically infeasible. Though dielectric oil or compressed-air circuit breakers have been used historically, these units require large equipment components to achieve the same insulating capabilities of SF_6 circuit breakers. In addition, per an EPA report, "no clear alternative exists for this gas that is used extensively in circuit breakers, gas-insulated substations, and switch gear, due to its inertness and dielectric properties."[11] According to the report NTIS Technical Note 1425, SF_6 is a superior dielectric gas for nearly all high voltage applications.[12] It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance through many years of use and investigation. It is clearly superior in performance to the air- and oil-insulated equipment used prior to the development of SF_6-insulated equipment. The report concluded that although "various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture … it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment."

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

Energy, environmental, or economic impacts are not addressed because the use of the highest ranked remaining control technology – state-of-the-art SF_6 technology with leak detection – is being proposed to limit fugitive emissions from the circuit breakers.

Step 5 – Selection of BACT

EPA concludes that using state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection is BACT. The circuit breakers will be designed to meet the latest American National

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[11] U.S. Environmental Protection Agency. 2008. *SF_6 Emission Reduction Partnership for Electric Power Systems 2007 Annual Report*. Available at: http://www.epa.gov/electricpower-sf6/documents/sf6_2007_ann_report.pdf.
[12] Chrsitophorous, L.G., J.K. Olthoff, and D.S. Green. 1997. *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6*. NIST Technical Note 1425.

Standards Institute (ANSI) C37.013 standard for high voltage circuit breakers.[13] 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.

Austin Energy will monitor emissions annually in accordance with the requirements of the Mandatory Greenhouse Gas Reporting Rules for Electrical Transmissions and Distribution Equipment Use.[14] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of 40 CFR Part 98, Subpart DD.

Austin Energy will implement the following work practices as SF_6 BACT:

- Use of state-of-the-art circuit breakers that are gas-tight and guaranteed to achieve a leak rate of 0.5% by year by weight or less (the current maximum leak rate standard established by the International Electrotechnical Commission);
- An LDAR program to identify and repair leaks and leaking equipment as quickly as possible;
- Systematic operations tracking, including cylinder management and SF_6-gas recycling cart use; and
- Educating and training employees with proper SF_6 handling methods and maintenance operations.

XII. 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 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 has reviewed and adopted a Biological Assessment (BA), dated May 15, 2014, prepared by TRC Environmental Corporation (TRC) on behalf of City of Austin (dba Austin Energy) ("Austin Energy") and EPA. The draft BA identified fifteen (15) species listed as federally endangered or threatened in Travis County, Texas:

Federally-Listed Species for Jefferson County by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Interior least tern	*Sterna antillarum athalassos*
Golden-cheeked warbler	*Setophaga chrysoparia*
Whooping crane	*Grus americana*

[13] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*
[14] See 40 CFR Part 98 Subpart DD.

Black-capped vireo	*Vireo atricapilla*
Mammals	
Red wolf	*Canis rufus*
Arachnids	
Bee Creek Cave harvestman	*Texella reddelli*
Bone Cave harvestman	*Texella reyesi*
Tooth Cave pseudoscorpion	*Tartarocreagris texana*
Tooth Cave spider	*Neoleptoneta myopica*
Insects	
Kretschmarr Cave mold beetle	*Texamaurops reddelli*
Tooth Cave ground beetle	*Rhadine persphone*
Fish	
Smalleye shiner (proposed Endangered)	*Notropis buccula*
Amphibians	
Austin blind salamander	*Eurycea waterlooensis*
Barton Springs salamander	*Eurycea sosorum*
Jollyville Plateau salamander	*Eurycea tonkawae*

EPA has determined that issuance of the proposed permit to Austin Energy for a new natural gas-fired combustion turbine and heat recovery steam generator at an existing electric generation facility will have no effect on the fifteen (15) federally-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.

XIII. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties on or eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report, dated May 16, 2014, prepared by TRC Environmental Corporation (TRC), a contractor to Austin Energy.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be 7 acre area that contains laydown area and construction footprint of the project. TRC performed a field survey of the property and a desktop review on the archaeological background and historical records within a 0.76-mile radius of the APE.

Based on desktop review, at least five previous cultural resource surveys, which included shovel testing, have been conducted within and around the APE. Based on the results of the previous surveys, 15 archaeological/historical sites are within a 0.76 mile radius of the APE and one of those sites is located within the APE. However, that site is not eligible for listing on the National Register of Historic Places. Based on the results of the surveys, no other historic structures eligible for listing on the National Register were identified within 0.76 miles of 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 archeological resources eligible for listing on the National Register is low within the construction footprint itself, issuance of the permit to Austin Energy will not affect properties on or potentially eligible for listing on the National Register.

On April 7, 2014, EPA sent letters to 26 tribes with a historic interest in Texas to inquire whether any of them were interested in participating as consulting parties 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 cultural resources report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XIV. 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.

XV. Conclusion and Proposed Action

Based on the information supplied by Austin Energy, our review of the analyses contained in 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 Austin Energy 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

Annual Facility Emission Limits

Table 1. Annual Emission Limits[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY		
SH8	SH8	Combustion Turbine	CO_2	1,460,386[4]	1,461,908	930 lbs CO_2/MWh on a 365-day rolling average basis. See permit conditions III.A.1 and Table 2.
			CH_4	27.5[4]		
			N_2O	2.8[4]		
PB-FUG MS-FUG	PB-FUG MS-FUG	Natural Gas Fugitives	CO_2	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of AVO Program. See permit conditions III.B.1.
			CH_4	No Numerical Limit Established[5]		
SF6-FUG	SF6-FUG	Electrical Equipment Fugitives	SF_6	No Numerical Limit Established[6]	No Numerical Limit Established[6]	See permit conditions III.B.2. through III.B.4.
Totals[7]			**CO_2**	**1,460,386**	**CO_2e 1,462,052**	
			CH_4	**33**		
			N_2O	**2.8**		
			SF_6	**0.00015**		

1. Compliance with the annual emission limits (tons per year) is based on a 365-day 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 turbine is based on operating at maximum duct burner firing for 8,760 hours per year. The annual emission limit includes emissions from MSS.
5. Natural gas emissions from EPNs PB-FUG and MS-FUG are estimated to be 5.64 TPY of CH_4, 0.13 TPY CO_2, and 141 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
6. SF_6 emissions from EPN SF6-FUG are estimated to be 0.00015 TPY of SF_6 and 3 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
7. The total emissions include the PTE for natural gas and electrical equipment fugitive emissions. These totals are given for informational purposes only and do not constitute emission limits.