Statement of Basis
Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
For APEX Bethel Energy Center, LLC

Permit Number: PSD-TX-104511-GHG

November 2013

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 June 21, 2012, APEX Bethel Energy Center, LLC (APEX) submitted to the EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project known as the Bethel Energy Center (Bethel) in Anderson County, Texas. On October 12, 2012, APEX submitted additional information for inclusion into the application. In connection with the same proposed construction project, APEX received Standard Permit No. 104511 for its non-GHG pollutants from the Texas Commission on Environmental Quality (TCEQ) on August 24, 2012. The project proposes to use the compressed air energy storage (CAES) technology developed by Dresser-Rand to produce up to approximately 317 MW of electrical power. The Bethel plant will consist of two expansion turbines/generating trains each rated at 158.34 MW. GHG pollutants occur primarily from the exhaust emissions from the natural gas combustion turbine trains, with minor emissions from fugitive sources and an emergency generator engine. The turbines will use selective catalytic reduction (SCR) for reduction of nitrogen oxides and catalytic oxidation to reduce carbon monoxide. After reviewing the application, the EPA Region 6 has prepared the following SOB and draft air permit to authorize construction of air emission sources at the APEX Bethel facility.

This SOB documents the information and analysis the EPA used to support the decisions the 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 will comply with the requirements.

The EPA Region 6 concludes that APEX’s application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. The EPA's conclusions rely upon information provided in the permit application, supplemental information requested by the EPA and provided by APEX, and the EPA's own technical analysis. The EPA is making all this information available as part of the public record.

II. Applicant

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Houston, Texas 77027

Facility Physical Address:
Intersection of County Rd. 2504 and F.M. 2706
Tennessee Colony, Texas 75861

Contact:
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Chief Operating Officer
APEX Compressed Air Energy Storage, LLC
(713) 963-8104

III. Permitting Authority

On May 3, 2011, the EPA published a federal implementation plan that makes the EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). The State of Texas still retains approval of its plan and PSD program for 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:
Bonnie Braganza
Air Permitting Section (6PD-R)
(214) 665-7340

Facility Location

The APEX Bethel Energy Center will be located near Tennessee Colony, Anderson County, Texas, and this area is currently designated "attainment" for all criteria pollutants. The nearest Class I area is the Wichita Mountains Wildlife Refuge, which is located well over 100 miles from the site. The geographic coordinates for this proposed facility site are as follows. Figure 1 illustrates the proposed facility location for this draft permit.

Latitude: 31º 53' 16" North
Longitude: -95º 54' 48" West

FIGURE 1
APEX Bethel Energy Center

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

The EPA concludes APEX Bethel's application is subject to PSD review for the pollutant GHG, as described at 40 CFR § 52.21(b)(1) and (b)(49)(v). Specifically, under the project, the potential GHG emissions are calculated to exceed the major source threshold on a mass basis, as provided at 40 CFR § 52.21(b)(1), and 100,000 tpy "CO_2-equivalent" (CO_2e), as provided at 40 CFR § 52.21(b)(49)(v) (APEX calculates CO_2e emissions of 459,040 tpy). The EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

The applicant represents that the proposed project is not a major stationary source for non-GHG pollutants. The applicant also represents that the increases in non-GHG pollutants will not be authorized (and/or have the potential) to exceed the "significant" emissions rates at 40 CFR § 52.21(b)(23). The applicant has indicated that the power generation will be limited to the NOx emissions in the TCEQ permit. At this time, TCEQ, as the permitting authority for regulated NSR pollutants other than GHGs, has issued the standard permit for electric generating facilities for non-GHG pollutants.[1]

In evaluating this permit application, the EPA Region 6 considers 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, the EPA has determined that compliance with the Best Available Control Technology (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. The applicant has submitted an impacts analysis of non- GHG pollutants to meet the requirements of 40 CFR §52.21(o), as it may otherwise apply to the project.

V. Project Description

The proposed GHG PSD permit, if finalized, would authorize APEX to construct a new compressed air energy storage (CAES) power plant near Tennessee Colony in Anderson County, Texas to produce up to 317 MW of electrical power. The facility will be known as the APEX Bethel Energy Center, LLC, referred to within this document as "APEX Bethel". CAES technology involves two major processes:

(1) Air compression and storage, and
(2) Air release for electricity generation.

During the air compression and storage process, electric motor driven compressors are used to inject air into an underground cavern for storage under high pressure. Electricity is generated by releasing the high-pressure air, heating it with natural gas combustion and expanding the air through sequential turbines (i.e., expanders), which in turn drive an electrical generator.

The site for the plant was selected to accommodate the high pressure storage of air in local underground caverns. The compressed air storage for APEX Bethel will be created by drilling a "cavern well" having a cemented well casing at a terminal depth of approximately 3,750 feet. Fresh water withdrawn from local groundwater wells will be pumped down the well to dissolve salt, creating the storage cavern. Salt brine withdrawn from the cavern during this "leaching" process will be injected into existing permitted brine disposal wells on nearby property. This leaching process is carefully controlled to produce a cavern of the desired capacity and shape. The cavern is expected to operate over a wellhead pressure range of approximately 1,900 to 2,830 psia (static pressure range). If full, the cavern will support approximately 100 hours of generation at near full rated output without recharge.

The CAES is a hybrid peaking power process using the energy of high pressure compressed air supplemented by natural gas fired multistage expansion turbines to generate electricity. The CAES plant compresses air utilizing grid power during off peak hours to store compressed air and then releases it to generate power to the grid during peak demand. Even though the CAES design includes the features similar to an industrial turbine, the design significantly differs from a conventional gas turbine. While the operation of the expander section for the conventional gas turbine operates at about the same pressure (254 psia) as the lowest pressure (third stage) expander for the CAES turbine/generator, a conventional gas turbine has a compressor and expander operating on a single shaft, resulting in a much

[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

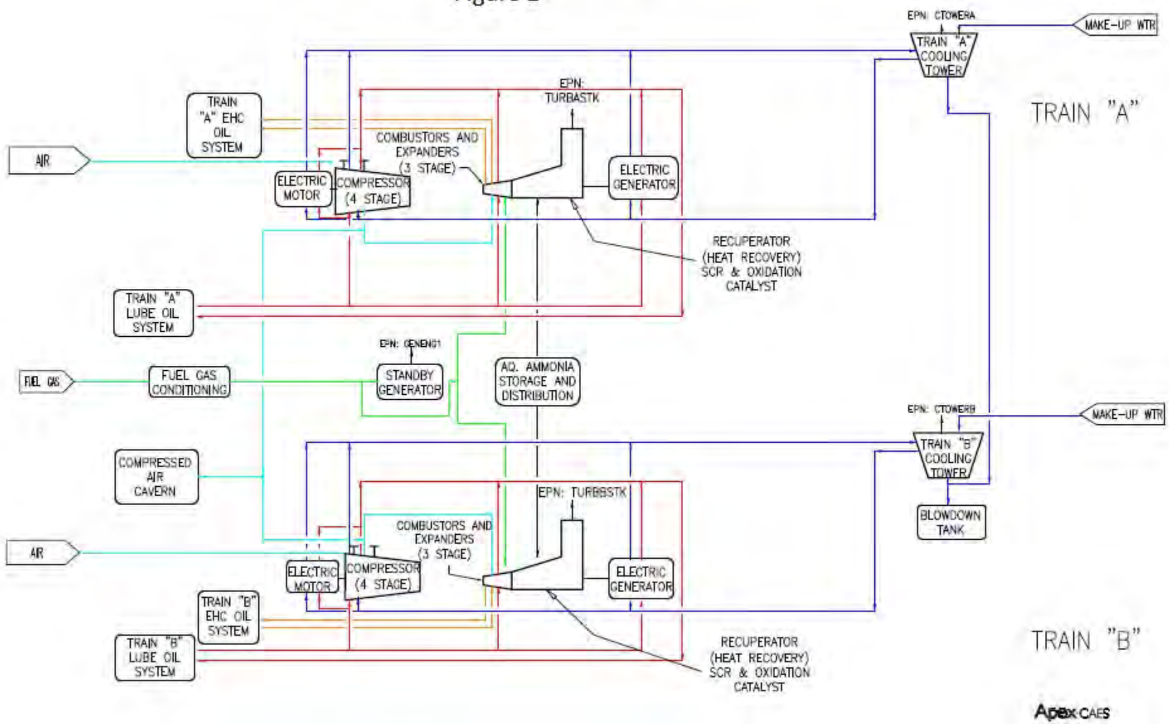
narrower turndown ratio than the APEX Bethel CAES design. The separation of the compression and expansion functions allows for greater operating flexibility for APEX Bethel to meet the Electric Reliability Council of Texas (ERCOT) market demands for energy during peak hours. The CAES multistage turbines operate from a 10% load range to full load at 100% with the ability to reach the required output within 5 minutes.

The APEX Bethel facility will comprise two Dresser-Rand CAES compression trains, each consisting of a set of multi-stage compressors driven by a dedicated 150 MW (nominal rating) electric motor. Each compression train will be capable of producing up to 1.4 million pounds per hour of air at a compressor outlet pressure of up to 2,830 psia. The process flow diagram for APEX Bethel is in Figure 2. It depicts the compressors, operating at design basis compression, under summer ambient conditions, and further assuming a "near" full cavern. Compression occurs in four stages. Because compression of air results in an increase in temperature, it is necessary to cool the air between the stages. Such cooling is accomplished via two heat rejection processes – an "air to air" heat exchanger and conventional shell and tube air to water heat exchangers, with the cooling duty split approximately 50/50 between each cooling method. Heated water from this process will be cooled in a conventional mechanical draft cooling tower. Make-up water to the cooling tower will be sourced from fresh water wells to be drilled in advance of plant operation to provide water for the cavern leaching process. Cooling tower blowdown will be discharged to the Trinity River. Maximum daily water consumption is expected to be approximately 1.8 million gallons. Annual water requirements are expected to be approximately 400 acre feet.

For power generation, the Bethel plant will consist of two Dresser –Rand expansion turbine/generator (ETG) trains (FIN/EPN TURBTRNA/TURBASTKA & TURBTRNB/TURBASTKB), each rated at 158.34 MW output at full load. The total generating capacity of the plant will be 317 MW (nominal power rating). High pressure air from the cavern passes sequentially through the three expanders, performing work (accompanied by a reduction in pressure) as the air flows through each stage of expansion.

Apex Bethel Train Flow Diagram

Figure 2



Each expansion train at the Bethel Energy Center will use three expanders, operating on a single shaft, connected to the generator during the expansion/generation process. High pressure (HP) air from the cavern passes sequentially through the three expanders (accompanied by a reduction in pressure) as the air flows through each stage of expansion. The APEX Bethel facility uses a HP topping turbine as the first stage of expansion followed by the HP intermediate stage and the low pressure (LP) stage of expansion operates at an inlet pressure of 228 psia.

At maximum generator output, approximately 400 lbm/second of air from the cavern header passes through a recuperator, where the air is preheated to a temperature of 600°F (degrees Fahrenheit) before entering the topping turbine, at a turbine inlet pressure of approximately 2,170 psia (at full rated output). Air is expanded in the topping turbine, resulting in a temperature and pressure drop. The air next flows to one of two high-pressure (HP) combustors. Pipeline quality natural gas is burned with the preheated air (from the recuperator) in the combustors, and the resultant heated gases enter the HP expanders at approximately 1,000°F and 800 psia. The gases exit the HP expanders to the last stage LP combustor, where additional natural gas is burned to increase the gas temperature for further expansion in the LP expander. Energy efficiency for this process is increased by making use of the heat from the flue gas to preheat the air to the combustors via the recuperator. The gases from the recuperator exhaust to the stack (EPN TURBASTK & TURBBSTK).

The addition of a topping turbine is a design feature unique to the Bethel plant and is made possible by the high pressure of the cavern in the plant. APEX Bethel chose this location on the basis of numerous site-specific geological and economic parameters, including ERCOT power market considerations, which is distinctively different from the existing CAES installation in McIntosh, Alabama (or at other sites which have been studied for CAES installation).

The proposed APEX Bethel Energy Center will also have a 740 kW emergency generator engine fired with natural gas (rich burn) and will utilize non-selective catalytic reduction (NSCR) for NOx reduction. The permit will restrict operations of the generator that includes maintenance and reliability testing to 50 hours per year.

There will be minor GHG fugitive emissions from equipment leaks and sulfur hexafluoride from the circuit breakers. Also there will be maintenance emissions from the natural gas pipeline/metering station that will vent 4 times a year.

Non-GHG emitting equipment consists of the cooling towers that cool compressed air and a 10,000 gallon 19% aqueous ammonia solution used for SCR to control NOx emissions from the combustors. The ammonia tank will be filled by vapor balance and will not have open vents; therefore, the ammonia delivery system only has fugitive emissions.

VI. BACT Analysis

The EPA conducted the BACT analyses as suggested in the EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines five 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 technologies;

4) Evaluate the most effective controls and document the results;

5) Select the BACT

Before discussing the BACT for the individual pieces of equipment, APEX Bethel provided a discussion on the need for grid level energy storage in the power (ERCOT) market for a quick response capability to supply electricity during peak demand. The CAES plant compresses air utilizing grid power during off peak hours to store compressed air and then releases it to generate power to the grid during peak demand. APEX indicates that at this time there are only two technologies, CAES and hydroelectric, that are commercially available and can provide sufficient storage capacity to be of value at the bulk power level. APEX conducted an evaluation of more than 20 potential sites in west and southeast Texas to identify potential cavern creation opportunities before selecting the Bethel Energy Center site. The Bethel Energy Center site was chosen for development of a CAES facility due to the presence of suitable geologic conditions, existing gas and electric transmission lines crossing the property, existing infrastructure to support cavern creation, and availability of groundwater as a water source.
Other commercially available technologies such as conventional gas turbine generation, wind, and solar are intermittent power sources and do not always provide the grid operator's need for flexible "standby"resources capable of responding quickly to deviations in system frequency. Therefore these technologies will not be evaluated in this BACT discussion, since the proposed project utilizing CAES meets all the APEX Bethel Energy Center requirements for economic operation within the ERCOT market. This is consistent with the EPA's March 2011 *PSD and Title V Permitting Guidance for Greenhouse Gases,* which states, "EPA has recognized that a Step 1 list of options need not necessarily

include inherently lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant…", and "…the permitting authority should keep in mind that BACT, in most cases, should not regulate the applicant's purpose or objective for the proposed facility…" (p. 26). Nonetheless, it should be noted that the APEX Bethel Energy Center is intending to provide secure, reliable capacity to the grid, assisting the grid operator in coping with the intermittent nature of solar and wind generation, and other renewable generation.

Applicable Emission Units for BACT Analysis.

The units/activities that directly or indirectly emit GHG emissions are:

- Gas Expansion Turbines (EPNs: TURBASTK and TURBBSTK)
- Fugitives (EPN: FUG1))
- Natural Gas Maintenance Purges (EPN: MAINT1)
- Emergency Generator (EPN: GENENG1)

1. Gas Expansion Turbines (EPNs: TURBASTK and TURBBSTK)

The APEX Bethel Energy Center will have two expansion turbine trains, with each train having a separate exhaust stack with a CO_2 analyzer. The turbines will utilize pipeline quality natural gas for combustion. APEX has estimated that the Bethel plant will have a maximum annual throughput of 7,807,409 MMBtu of natural gas for the combined trains with total CO_2 emissions of 456,296 tpy. The does not include natural gas usage at other sources such as emergency generator. The combustion turbines will be using SCR and oxidation catalyst which will increase the GHG pollutants by a small amount. The estimated emissions from the turbines of N_2O and CH_4 as CO_2e comprise about 0.54% of the total CO_2e from the turbines. Therefore the BACT analyses will focus primarily on technology to reduce CO_2 emissions. As part of the PSD review, APEX provided a five-step top-down BACT analysis for the combustion turbines in the GHG permit application. The EPA has reviewed APEX Bethel's BACT analysis for the gas expansion turbine trains, which has been incorporated into this Statement of Basis, and also provides its own analysis in setting forth BACT for this proposed permit as summarized below.

Step 1 – Identify All Available Control Options

- *Carbon Capture Sequestration (CCS)* – CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.
- *Use of a Low Carbon Fuel for Combustion*
- *Electrical Generation Conversion Efficiency* – the formation of GHGs can be mitigated by design and selection of ultra-efficient combustion units.
- *Operational Energy Efficiency – Good combustion, operating and maintenance practices are a potential control option for improving the fuel efficiency of affected combustion units.*

Carbon capture and storage is a GHG control proce**ss** that can be used by 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 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 available to gas 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). As such, post-combustion capture is the sole carbon capture technology considered in this BACT analysis.

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]

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project, except for CCS.

- **Carbon Capture and Storage (CCS)**

APEX estimated the CO_2 concentration in the turbine exhaust stacks would be in the range of 1.7 – 3.5%, based on fuel consumption and stack flow of 99,000 to 453,000 acfm at a temperature of 230^0F. CCS has not been demonstrated in practice on emissions streams like this that are more dilute in CO_2 concentration. Although CCS technology is generally available from commercial vendors, we do not have information indicating that this technology can be applied to more dilute emissions streams. Thus,

[2]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011)
[3] 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

we do not have sufficient information at this time to determine CCS to be technically feasible for the exhaust streams at this facility.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Other than CCS, which was eliminated in Step 2 above, the remaining technologies to reduce GHG are being evaluated for this project and we will rank these measures in Step 4.

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

Use of a Low Carbon Fuel

APEX proposes to use natural gas for combustion in the turbine expanders. The only other low carbon combustion fuel is hydrogen and this is not commercially available at this particular site. Typically hydrogen gas is a byproduct process vent gas in large chemical and refining plants and enters the plant fuel grid system. In this project, there are no processes that produce hydrogen and therefore natural gas is the commercially available low carbon fuel for combustion.

Energy Efficiency Design Measures for the Turbines/Generators

The APEX Bethel plant is designed to utilize high-efficiency, state-of-the-art, expansion turbines and associated combustors. Table 4 lists designs of CAES power generation plants.

Table 4

	APEX	**Chamisa CAES**[1]	**McIntosh**[2]	**Huntorf**[2]
Power Production Capacity, MW	317 (total of 2 trains)	280 (total of 2 trains)	110	290
Heat Rate at aximum Production, BTU (HHV)/KWH	4,262 (gross)- 4,390 (net)	4,389 (gross)- 4,502 (net)	4,555	6,175
Design Recuperator Efficiency,%	90	90	70	N/A (no recuperator)
No. of Expanders	3	2	2	2
Cavern Pressure, psig	1,900-2,830	940-1,800	1,100	600-1,000
Hours of Storage	100	36 - 48	26	3-4

1. *Chamisa is a current Region 6 permit application that is being processed for a permit*
2. *Both of these plants are operating*
3. *The APEX and Chamisa heat rates do not reflect the 3% adjustment for performance degradation*

Energy efficiency is normally expressed in terms of heat rate. The APEX turbine trains have an estimated heat rate of 4,390 BTU/kWh at maximum load and 4,773 BTU/kWh at low load (HHV basis). The heat rates have been adjusted to reflect a 3% degradation between system overhauls (per Dresser-Rand guidance). The energy efficiency for APEX Bethel are reflective of heat input divided by generator output measured at the generator terminals. Performance figures for APEX reflect site conditions at 60°F. There are two CAES facilities in operation worldwide: McIntosh, in Alabama, and the Huntorf facility in Germany. The addition of a topping turbine is a design feature not present in the two operational CAES plants and therefore allows for greater efficiency. Huntorf, completed in 1978, is a 290 MW facility designed and built by Brown Boveri Corporation (now a component of Asea Brown

Boveri (ABB)). Huntorf was originally built to provide peaking power service, as well as black-start capability for nuclear power units in the region. Today the plant has increasingly seen use to help balance wind generation in northern Germany. Huntorf was constructed without a recuperator in order to minimize system start-up time. The table above also lists one proposed facility (Chamisa CAES at Tulia, LLC) currently going through the construction permitting process. The Chamisa facility will have a two stage expander like McIntosh.

McIntosh was placed in commercial operation in 1991 as a single train CAES facility, rated at 110-MW output. McIntosh used a novel “motor/generator”, whereby a single electrical machine fulfilled dual roles as a motor for compressing, and as a generator when operating in the expansion mode. As with APEX Bethel the compressor is electric driven with no GHG emissions and the expanders are natural gas combustors from Dresser-Rand. It should also be noted that the cavern air storage pressures are considerably higher for the APEX plant which also provides for additional storage for extended power generation.

The expander train design features the HP and LP expanders and associated combustors at APEX which are very similar to the McIntosh equipment with one exception - the APEX design has an additional HP topping turbine to accommodate the higher cavern well-head pressure. Also, the APEX-HP expander will operate at a higher full load inlet pressure than McIntosh (800 psia vs. 630 psia at McIntosh). Additionally, the APEX combustors will use SCR for NO_X control unlike the McIntosh plant.

The most important contributor to optimizing the energy efficiency for APEX is the improved recuperator efficiency at Bethel Energy Center (90% for APEX versus 70% for McIntosh). Other design changes have a meaningful impact on output (and hence capital cost on a $/kW basis) and specific air consumption, but they do not affect heat rate materially. The heat rate advantage of APEX in table 4 above supports a determination that APEX will have energy conversion efficiency higher than CAES units currently in existence.

As shown in table 4, the heat rate for APEX represents a 31 percent improvement in comparison to Huntorf, and a 6 percent improvement in comparison to McIntosh. The design heat rate for APEX (not adjusted for equipment degradation) was used for this computation, to be consistent with data available for the other two operating and one proposed CAES installations.

Separating the compressor from the combustion expander and generator has additional advantages such as utilizing an electric compressor with no GHG emissions during non-peak hours for the compression of air and, when necessary for additional power generation, having both operations (compression and generation)at the same time.

Operational Energy Efficiency

Additional BACT considerations are good operating and maintenance practices to ensure complete combustion of the natural gas fuel, maximize heat recovery by monitoring the exit flue gas parameters to optimize the air/fuel ratio in the combustors. The design and maintenance will take into consideration insulation materials to minimize heat loss from the expanders, combustors, ducts, and the recuperator. Heat loss from the expanders and combustors will be further mitigated by the fact that these components will be housed within a building – i.e. not exposed to the elements.

Step 5 – Selection of BACT

The following are the specific BACT limits and conditions for the combustion turbines.

1. BACT output limit of 558 lbs CO_2/MWH (net) for both trains on a 365-day rolling average.
2. Combustion efficiency of 4773 BTU/kWh for all combustors on a 365-day rolling average.
3. Good maintenance practices according to the vendor's recommendation attached to the permit.
4. Insulation and maintenance of insulation on all combustors and recuperators for minimizing heat loss.
5. Process controls and instrumentation to optimize fuel/air rations and minimize fuel gas use.

The proposed BACT limit of 558 lbs CO_2/MWh directly measures and reflects the overall process efficiency of the gas expansion turbine trains. The limit proposed takes into account the range of loads from the lowest sustainable load of 25% to 100% load, which reflects the highest production rate of CO_2 over the full operational range. These values reflect a maximum 3% deterioration in turbine performance between overhauls. Over the operating range of 44% to 100% load, the vendor performance data indicates a heat rate of 4,390 to 4,499 Btu (HHV)/kWh, inclusive of the aforementioned degradation adjustment. At lower loads, the heat rate would gradually increase to a maximum of 4,773 Btu (HHV)/kWh(net) at the lowest sustainable load (11%), which is the permit limit in the draft permit.

On March 27, 2012, the EPA proposed a New Source Performance Standard (NSPS), 40 CFR Part 60 Subpart TTTT that would control CO_2 emissions from new electric generating units (EGUs).[4] The proposed rule would apply to fossil-fuel fired EGUs that generate electricity for sale and are larger than 25 MW. The EPA proposed that new EGUs meet an annual average output based standard of 1,000 lb CO_2/MWh, on a gross basis. The proposed emission rate for the APEX gas expansion turbine trains on a net electrical output basis is 558 lb/MWh. The proposed CO_2 emission rates from the APEX turbine trains are well within the emission limit proposed in the NSPS at 40 CFR Part 60 Subpart TTTT.

2. Emergency Engine (EPN: GENENG1)

In addition to the two combustion turbine trains planned for the Bethel Energy Center, one natural gas-fired emergency generator (nominal 1,053-BHP engine with estimated emissions of 23 CO2e tpy) will operate at the plant.

Step 1 – Identification of Potential Control Technologies

The available control technologies for the natural gas generator are identical to those identified for the combustion turbines. These options include

- Carbon Capture and Storage Systems (CCS)
- Generator Engine Design Efficiency
- Use of a Low Carbon Fuel

Step 2 – Elimination of Technically Infeasible Alternatives

[4] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 Fed Reg 22392, April 13, 2012. Available at http://www.epa.gov/ttn/atw/nsps/electric/fr13ap12.pdf

- *Carbon Capture and Storage* – As discussed above, CCS for GHG control has been eliminated as a not technically feasible control option for an emergency generator that has intermittent operations for only 50 hours/year. Therefore, CCS is eliminated from further consideration for natural gas emergency generator engine GHG reduction.

- *Generator Engine Design Efficiency* – The natural gas generator engine for the Bethel Energy Center will incorporate a high-efficiency design. The table below provides a comparison of similar sized gas fired units from different manufacturers. The annual CO_2e emissions difference between the two units is approximately 1.1 tons per year. The Caterpillar unit selected by APEX, prior to add-on NSCR controls, provides lower NOx and VOC emissions than the Waukesha counterpart. With the addition of NSCR controls, the NOx, VOC, and CO emissions are substantially lower. Thus, the criteria pollutant emissions reductions were determined to be an acceptable trade-off, with more overall benefit to the environment, than a slightly better efficiency (Btu/bhp-hr) with the Waukesha unit.

	Selected Generator Caterpillar G3516SITA	Similar Generator Waukesha VHP7100G
kW (bhp)	740 (1,053)	725 (1,025)
Btu/bhp-hr	7,391	7,223
Fuel Use (scf/hr)	8,600	8,181

- *Efficient Use of Energy* – The natural gas generator engine will not be operated continuously, but only during maintenance testing and during emergencies for backup power generation. Therefore, energy will be utilized in an efficient manner.

- *Use of Low Carbon Fuel* – The generator will use natural gas for fuel instead of diesel that is typically used for emergency generators. The use of natural gas yields the lowest emissions of GHG.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technically feasible GHG control technologies for the Bethel Energy Center are “Efficient Use of Energy” and “Use of Low Carbon Fuel.” These technologies are equally important toward minimizing GHG emissions.

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

The remaining technically feasible GHG control technologies are “Efficient Use of Energy” and “Use of Low Carbon Fuel.” These technologies will be implemented for the generator engine.

Step 5 – Selection of BACT

The following are the BACT requirements for the diesel-fired emergency generators:

- *Low Carbon Fuel* – The emergency engine will be natural gas-fired.

- *Efficient Use of Energy* : Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing, and operations within the recommended air to fuel ratio, as specified by its design. Engines have an operational limit of 50 hours per year.

3. Fugitive Emissions (EPN: FUG1)

In addition to the combustion sources planned for the Bethel Energy Center, there are hydrocarbon emissions from leaking piping components, which include methane emissions from the natural gas pipeline. There are also sulfur hexafluoride (SF6) leaks from circuit breakers. Although this is a small source with an estimated 248 tpy CO_2e or 0.05 percent of the total site emissions, for completeness, fugitive emissions are addressed in this BACT analysis.

a. CH_4 Fugitives from piping and equipment components

Step 1 – Identification of Potential Control Technologies for GHGs

The available control technologies for process fugitive emissions are as follows

- Installing Leakless Technology and high quality components and materials of construction to minimize fugitive emission sources
- Implementing a Leak Detection and Repair (LDAR) Program using traditional flame ionization detector (FID), new infrared (IR) camera technology or handheld analyzer to detect methane emissions.
- Comprehensive Maintenance program consisting of a monthly walk-through to check for leaks, with repairs or replacement completed within 15 days and records documenting the program and leaks made available upon inspection.

Step 2 – Elimination of Technically Infeasible Alternatives

Leakless Technology – APEX will use welded piping where possible, high quality components and materials for design and construction of the Bethel Energy Center. The cost of implementing this will be included in the cost of construction. Other components such as flanges and valves inherently cannot be leakless, and the facility cannot be constructed, operated or maintained without the use of flanges and valves. Therefore installing leakless technology is technically infeasible for controlling process fugitive GHG emissions from flanges and valves.

LDAR Programs – LDAR programs are a technically feasible option for controlling process fugitive GHG emissions from components in natural gas service.

The *Comprehensive Maintenance* program is feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

All the above BACT technologies with the exception of leakless design for flanges and valves are technically feasible and effective to minimize GHG emissions.

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

LDAR Programs – There are varied levels of stringency in LDAR programs for controlling volatile organic compound (VOC) emissions, using an organic detector.

Although technically feasible, the use of an LDAR program to control less than .06% of GHG emissions is not cost effective, as shown below. The estimates were from a company utilizing the LDAR program for a small gas plant subject to 40 CFR Part 60, Subpart KKK with around 600 components to monitor quarterly. The cost would be as follows:

- $16,000 for the first year, which includes tagging and initial monitoring.
- $12,000 for annual monitoring.

At an estimated cost of $176/ton GHG, the use of an LDAR or LDAR like program would not be cost effective for the Bethel Energy Center.

Comprehensive auditory, visual and olfactory (AVO) *Maintenance Program* – Another option for minimizing fugitive emission is to apply a comprehensive equipment maintenance program. The cost of this program would be rolled into the normal operation and maintenance of the facility. The comprehensive equipment maintenance program will have similar reduction percentages to a LDAR program and the associated costs can be rolled into normal operations without additional capital. Therefore, an LDAR program can be eliminated.

The comprehensive maintenance program proposed by APEX will include periodic inspections for leaks using (AVO methods to find leaks. Elements of the program include at a minimum the following:

- Walk through using AVO to identify leaks;
- First attempt to repair within 5 days and repair or replace within 15 days;
- Exceptions for components that require a process unit shut down or waiting on parts to repair or replace;
- Records of leaks and repairs shall be kept and made available upon request.

Step 5 – Selection of BACT

BACT is determined to be the comprehensive maintenance program as proposed by APEX using AVO to determine leakers on a daily basis.

b. SF_6 Insulated Electrical Equipment

SF_6 is commonly used in circuit breakers associated with electricity generation equipment. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 2,190 lb of SF_6.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Evaluating alternative substances to SF6 (e.g., oil or air blast circuit breakers);*
- *Use of new and state-of-the-art circuit breakers that are gas-tight and require less* SF_6
- *Implementing a leak detection program, such as a LDAR program or an equivalent program to identify and repair leaks and leaking equipment as quickly as possible.*

Step 2 – Elimination of Technically Infeasible Alternatives

According to the report NIST Technical Note 1425[5], 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 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.

The traditional LDAR program using a Flame ionization detector (FID) will not detect SF_6. An Infrared camera can detect leaks of SF_6 if calibrated for SF_6. The alternate leak detection program of a low pressure alarm, lockout and inventory accounting program (40 CFR §98.303(a), Equation DD-1), is an alternate operation for the enclosed pressure circuit breakers.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness
The remaining control options are not mutually exclusive and are all evaluated in Step 4.

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 alternative, non-greenhouse gas substance for SF_6 as the dielectric material in the breakers is not technically feasible.

Step 5 – Selection of BACT

The following are the specific BACT requirements for the SF_6 Insulated Electrical Equipment:

- The use of state-of-the-art enclosed-pressure SF_6 circuit breakers. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) and C37.013 standard for high voltage circuit breakers.[6]
- Installation of a low pressure alarm and low pressure lockout device. This alarm will function as an early detector that will detect potential fugitive SF_6 emission problems before a substantial portion of the SF_6 is released. The lockout prevents any operation of the breaker due to the lack of " quenching and cooling" SF_6 .
- Adoption of an inventory accounting program per 40 CFR §98.303.

4. Natural Gas Maintenance Purges (EPN: MAINT1)

Quarterly maintenance purges from the natural gas supply have been conservatively estimated at 0.015 tpy of methane, equivalent to .26 tons/yr of CO_2e.

Step 1 – Identification of Potential Control Technologies for GHGs

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[5] 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

[6] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.

- *Use of a Flare or other Control Device*
- *Minimization of Purges*

Step 2 – Elimination of Technically Infeasible Alternatives

Both options are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Flaring of maintenance purges would reduce CH_4 and other hydrocarbons by 98%, CO_2e emissions would be reduced by 81% since the combustion of the hydrocarbon emissions would result in the formation of CO_2.

- Minimizing purges would cause fewer emissions.

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

Rental and operation of a portable flare once per quarter for the maintenance purge has been estimated by APEX to cost approximately $3,500 per quarter or $14,000 annually. The cost to reduce the methane emissions by 98% (0.0125tpy) is approximately $1,1200,000/ton. Therefore this alternative has been eliminated in this step.

Step 5 – Selection of BACT

BACT consists of good design to minimize the length of piping to be purged, and minimizing the purging to once every quarter. The purges are a necessity for safe operation of the plant.

VII. Compliance Monitoring:

<u>Turbine Generators</u>:

1. All continuous emission monitoring, instrumentation and metering equipment should meet specification requirements of 40 CFR § 75.10 and 40 CFR § 98.34 and subpart D requirements.
2. CO_2 analyzer in the stack to meet requirements of 40 CFR § 75.10(a)(3)-(5).
3. Monitor the fuel flow rate to the turbines to meet requirements in 40 CFR § 75.10, with an operational non-resettable elapsed flow meter.
4. Determine the specific fuel factor for the Fc and the Gross Calorific Value (GCV)(HHV) on a semi-annual basis using the equation F-7b in 40 CFR Part 75, Appendix F § 3.3.6.
5. Monitor and record the startup and shutdown events to include the duration and CO_2 emissions per event.
6. Use the CO_2 CEMS to determine compliance with the 558 lbs CO_2/MWH on a 365 daily rolling average.
7. Monitor and record the MMBTU/kWh to be less than 4773 on a 365-day rolling average.
8. Monitor the fuel flow rate to each turbine combustor as not to exceed the maximum heat input of 695.1MMBtu/hr calculated on a 365 daily rolling average.

9. Maintain the turbines according to manufacturer's recommendation for optimum performance. Keep all records of maintenance.
10. Conduct an initial test to demonstrate the turbine efficiency according to the conditions specified in the permit. Determine and record the stack temperature, flow rate and other parameters at various turbine rates of 11%, 50% and 75% capacity.

Emergency Generator:

1. Monitor and record the fuel flow rate and duration in hours used for reliability testing.
2. Monitor and record the fuel used and duration in hours used for emergency events.
3. Maintain and operate according to manufacturer's requirements. These documents should be readily available at the plant site and provided to an inspector.

Fugitive and Maintenance Emissions:

1. Keep records of the monitoring of the fugitive emissions of the natural gas pipelines to include the dates, the number of leakers, attempt at repair, and when repair was completed.

2. Keep records of the duration and number of events of pipeline purging for maintenance.

3. For SF_6, the emissions shall be calculated annually in accordance with the mass balance approach provided in 40 CFR § 98.303(a), Equation DD-1. All reports of maintenance performed and compliance with the Monitoring and Quality Assurance and Quality Control (QA/QC) procedures in 40 CFR § 98.304.

4. Keep records of the low pressure alarms and lockout occurrences and of possible releases to the atmosphere of SF_6 using the equation on 40 CFR §98.303(a), Equation DD-1, and the action taken to fix the problem.

VIII. Endangered Species Act (ESA)

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, the EPA is required to insure that any action authorized, funded, or carried out by the 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, the EPA is relying on a Biological Assessment (BA) prepared by the applicant, APEXAPEX, and its consultant, CH2M Hill, and adopted by the EPA.

A draft BA has identified nine (9) species listed as federally endangered or threatened in Anderson County, Texas:

Federally Listed Species for Anderson 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 anthalassos*
Piping plover	*Charadrius melodus*
Red-cockaded woodpecker	*Picoides borealis*
Sprague's pipet	*Anthus spragueii*
Whooping crane	*Grus americana*
Reptile	
Louisiana pine snake	*Pituophis ruthveni*
Plant	
Earth fruit	*Geocarpon minimum*
Mammals	
Louisiana black bear	*Ursus americanus luteolus*
Red wolf	*Canis rufus*

The EPA has determined that issuance of the proposed permit will have no effect on any of the nine 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 the 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.

IX. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires the 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, the EPA relied on a cultural resource report prepared by William Self Associates, Inc. (WSA) on behalf of APEX's consultant, CH2M Hill, submitted on March 20, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 213.5 acres of land that contains the construction footprint of the project, a proposed water/wastewater line route, a proposed alternate wastewater line route, a proposed water/wastewater reroute and a proposed brine line route. WSA conducted a field survey, including shovel testing, of the property and desktop review within a 0.5-mile radius APE. This review included a search of the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA). Based on the desktop review for the site, within a 0.5-mile radius of the area of potential effect, sixteen (16) architectural/archaeological sites, including a cemetery, were identified; three (3) of the sites are eligible or potentially eligible for listing in the National Register (NR), all of which are outside of the APE. Based on the results of the field survey of the APE, one newly recorded historic-age archaeological site and two previously recorded sites were identified; however, none of these sites were recommended to be eligible for listing on the NR.

The EPA Region 6 determines that while there are cultural materials of historic age identified within the 0.5-mile radius of the project area, issuance of the permit to APEX will not affect properties eligible or potentially eligible for listing on the National Register. Additionally, no historic properties are located within the APE and that a potential for the location of archaeological resources is low within the construction footprint itself.

On April 19, 2013, the EPA sent letters to 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 the EPA in the Section 106 process. The EPA received no requests from any tribe to consult on this proposed permit. The 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.

X. 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 the 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 the 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.

XI. Conclusion and Proposed Action

Based on the information supplied by APEX, 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 GHG under the terms contained in the draft permit. Therefore, the EPA is proposing to issue the PSD permit for GHG for the APEX Bethel Energy Center, 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 the EPA after considering comments received during the public comment period.

APPENDIX

Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month, rolling average, shall not exceed the following:

Table 1. Facility Emission Limits[1]

EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
			TPY[2]		
TURBASTK TURBSUA, TURBSDA and TURBBSTK TURBSUB, TURBSDB	Combined Gas Expansion Turbine Train A and Train B	CO_2	456,296	458,769	i. BACT of 558 lb CO_2/MWh[5] on a rolling 365-day average. ii. See Special Condition III.A. iii. Maximum heat input to one train is 695.1MMBtu/hr. iv. Work practice standards in Section III.A.
		CH_4	12.66		
		N_2O	7.12		
FUG1	Fugitives	CO_2	No Numerical Limit Established[4]	No Numerical Limit Established[4]	Implementation of AVO program. See Special Condition III.B.
		CH_4	No Numerical Limit Established[4]		
		SF_6	No Numerical Limit Established[4]		
GENENG1	Natural Gas-Fired Emergency Generator	CO_2	23	23	Good Combustion and Operating Practices. Limit to 50 hours of operation per year. See Special Condition III.C.
MAINT1	Maintenance	CO_2	0.01	0.26	See Special Condition III.D.
		CH_4	0.014		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling average.
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 to include startup and shutdown activities.
3. Global Warming Potentials (GWP): CH_4 = 21, N_20 = 310, SF_6 = 23,900. On January 1, 2014, the EPA anticipates the GWP for CH_4, N_2O and SF_6 will change to 25, 298, and 22,800 respectively. This change will impact the CO_2e calculations and the currently proposed emission limits will be revised to reflect the new CH_4 GWP in the final permit
4. Fugitive emissions (EPN FUG1) are estimated to be 0.27 tpy CO_2, 5.56 tpy CH_4 and 0.0065tpy SF_6 for a total of 248 tpy CO_2e. The emission limit will be a design/work practice standard as specified in the permit
5. Electrical output shall be measured at the generator terminals.