Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the El Paso Electric Company, Montana Power Station

Permit Number: PSD-TX-1290-GHG

September 2013

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

I. Executive Summary

On April 20, 2012, El Paso Electric Company (EPEC) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions from its proposed Montana Power Station. The Montana Power Station is to be a new 400 MW (nominal) electric power plant in El Paso County, Texas including four General Electric (GE) natural gas-fired turbines (Model LMS100) and associated equipment, including cooling towers, a firewater pump engine, ammonia storage tanks and unloading system, circuit breakers and a diesel storage tank. In connection with the same proposed project, EPEC submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on April 20, 2012.

The draft permit, if finalized as proposed, would authorize GHG emissions from the four turbines, firewater pump engine, circuit breakers, maintenance, startup and shut down emissions and fugitive leak emissions. The remaining units are not considered to be potential GHG emission sources. After reviewing the application and supplemental information provided by EPEC, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the Montana Power Station.

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

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

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

II. Applicant

El Paso Electric Company
Montana Power Station
100 N. Stanton
El Paso, TX 79901

Facility Physical Address:
Texas and Pacific Railway Surveys: Section 25, Block 79, Township 2
El Paso, TX 79938

Contact:
Mr. Andres R. Ramirez
VP-Power Generation
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III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). Texas 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:
Melanie Magee
Air Permitting Section (6PD-R)
(214) 665-7161

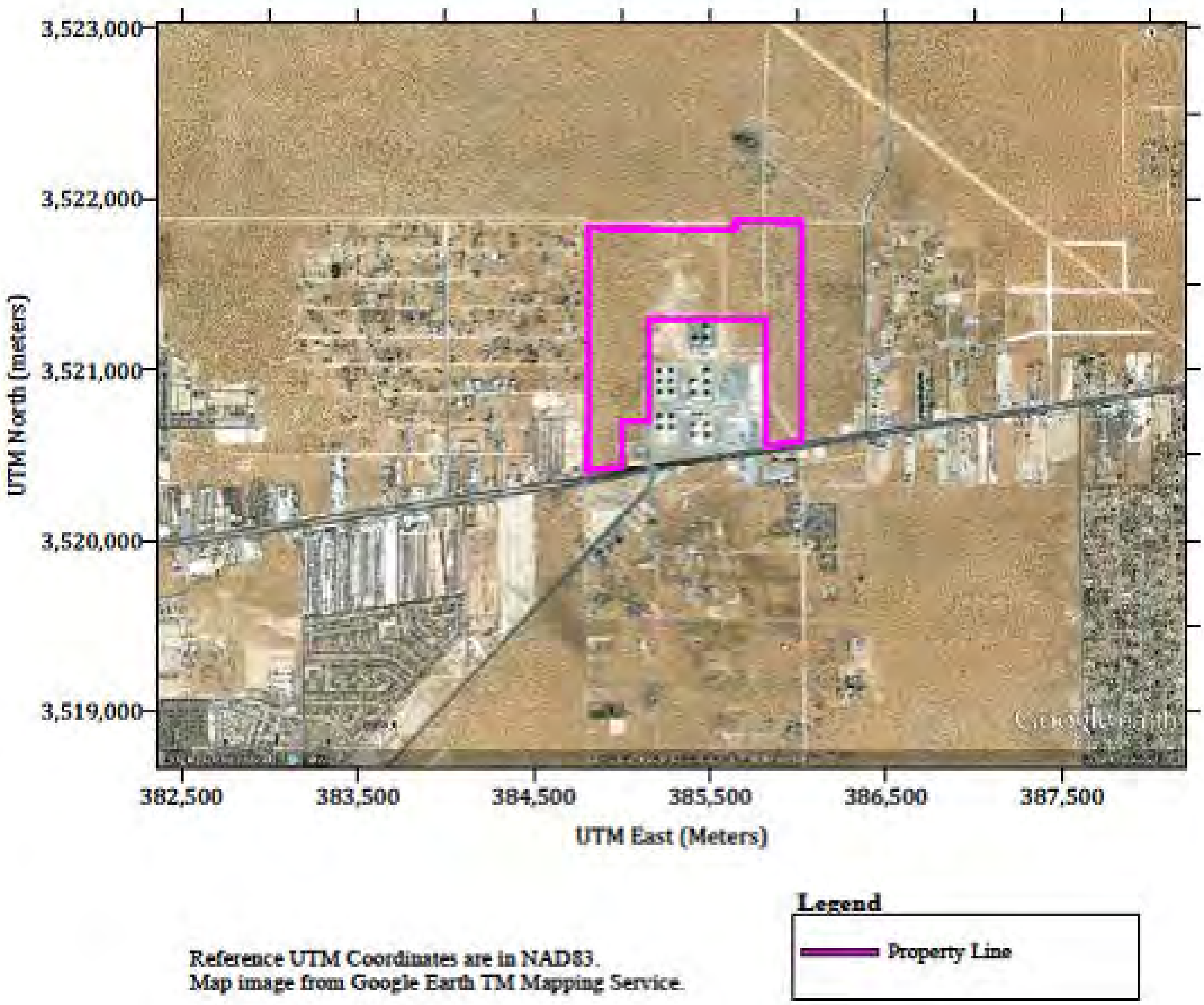
IV. Facility Location

The Montana Power Station is proposed to be located in eastern El Paso County, Texas. The new plant site is located on undeveloped land in east El Paso County, adjacent to Montana Avenue near Zaragoza Avenue, outside of the El Paso city limits. This site is bordered by Fort Bliss on the north, Montana Avenue on the south and is just over one mile east of the El Paso City limits. This location is currently designated as attainment or unclassifiable for all criteria air pollutants. The geographic coordinates for this facility are planned to be as follows:

Latitude: 31° 49’ 26”
Longitude: 106° 12’ 43”

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

Figure 1. Montana Power Station Proposed Site Location



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

EPA concludes EPEC's application is subject to PSD review for the pollutant GHGs because the project would lead to an emissions increase of GHGs for a facility as described at 40 CFR § 52.21(b)(49)(v). Under the project, increased CO_2e emissions are calculated to exceed the applicability threshold of 100,000 tpy CO_2e and 250 tpy GHGs at a new stationary source.[1]. 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.

EPEC represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will determine that the Montana Power Station is also subject to PSD review for increases of nitrogen

[1] EPEC calculates CO_2e emissions of 1,005,079.7 tpy, including fugitive emissions from circuit breakers and natural gas piping components.

oxides (NOx), carbon monoxide (CO) and particulate matter, including particulate matter less than 10 microns and less than 2.5 microns in diameter ($PM/PM_{10}/PM_{2.5}$). 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.[2]

By a letter dated February 13, 2013, TCEQ has explained to EPA Region 6 the basis for TCEQ's view that it has the legal authority to issue permits meeting PSD requirements for regulated NSR pollutants other than GHGs for sources that are major sources based solely on the level of GHG emissions. Based on these representations by TCEQ, EPA has communicated that it has no objection to TCEQ's proposal to address regulated NSR pollutants other than GHGs in PSD permits issued in conformity with state law and TCEQ's EPA approved PSD rules.[3] Under the circumstances of this project, EPA will therefore issue a PSD permit covering GHG emissions, while the state will issue a PSD permit covering emission of all other regulated NSR pollutants increased or emitted in amounts equaling or exceeding the significant emissions rates.

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have neither required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from TCEQ. Thus, TCEQ's PSD permit that will address regulated NSR pollutants other than GHGs should address the additional impacts analysis and Class I area requirements for other pollutants as appropriate.

On September 20, 2013, EPA signed a proposed NSPS that could ~~have~~ influence ~~on~~ the ultimate emission requirements for this source. ~~Specifically, t~~ The definition of BACT in PSD rules at 40 CFR 52.21(b)(12) states that "in no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61." Although this facility may be within the source category covered by the proposed NSPS, the proposed NSPS emission limits are not a controlling floor for BACT purposes since the proposed NSPS is not a final action and the proposed standard may change. However, the NSPS is an independent requirement that will apply to any source subject to the NSPS that commences construction after the date the NSPS is proposed (unless that source is covered by a transitional source exemption adopted in the NSPS). Thus, this facility may ultimately be subject to, and need to comply with, the NSPS after it is finalized, even if the emissions limits in the final permit are higher than the NSPS. See EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) at 25.

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[2] *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

[3] Letter from EPA Region 6 Deputy Regional Administrator Samuel Coleman to TCEQ Executive Director Zak Covar (April 4, 2013).

VI. Project Description

EPEC proposes to construct a new power station, Montana Power Station, on a greenfield site generally located northeast of El Paso, Texas. The proposed Montana Power Station will consist of four (4) identical natural gas-fired simple cycle turbines with support equipment to provide peaking/intermediate load operation for the service area.[4] The four combustion turbine generators (CTG) will be the General Electric LMS100, each with a maximum base-load electric power output of approximately 100 megawatts (MW, nominal). This project also includes two cooling towers, one fire water pump, and other auxiliary equipment. Greenhouse gas (GHG) emissions will result from the following emission units:

- Four Simple Cycle Combustion Turbines (EPNs: GT-1, GT-2, GT-3 and GT-4);
- One Fire Water Pump (EPN: FWP-1);
- Fugitive Emissions from SF_6 Circuit Breakers (EPN: CTBR-SF6); and,
- Fugitive Emissions from Natural Gas Piping Components (EPN: FUG-1)

Peaking/Intermediate Load Operation

The North American Electric Reliability Corporation (NERC) is the entity certified by the Federal Energy Regulatory Commission (FERC) to establish and enforce reliability standards for the bulk power system. In an agreement between NERC and the Western Electricity Coordinating Council (WECC), the WECC provides the coordination and promotion of electric system reliability for a region that extends from Canada to Mexico, including all or portions of 14 Western states. As a member of the WECC, EPEC is required to plan and design a generation portfolio for the best economical and operational system for the service area. In addition, EPEC has mandatory and enforceable standards from NERC to ensure the reliable operation of the bulk electric system. The Public Utility Commission of Texas (PUCT) and the New Mexico Public Regulation Commission (NMPRC) are charged with evaluating the need for the Montana Power Station, and have concluded in connection with administrative proceedings for Unit Nos. 1 and 2 that the project "is necessary for the service, accommodation, convenience or safety of the public" (Texas) and "[t]he proposed Montana Units 1 and 2 are required by the public convenience and necessity and will not result in unnecessary duplication or economic waste. They are the most appropriate alternative among the range of resources considered by EPE to meet its capacity needs." (New Mexico)

As a public utility, EPEC generates, transmits and distributes electricity to an approximate 10,000 square mile service area located in the Rio Grande Valley in west Texas and south central New Mexico. The electricity demand for a service area typically requires coverage for base, intermediate, and peak loads. Currently, EPEC owns or has significant ownership interests in five electrical generating facilities (Palo Verde Nuclear Generating Station, Four Corners Generation Station, Rio Grande Generating Station, Newman Generating Station, and Copper Generation Station). From the five current electric generation facilities, the total electric generation capacity of EPEC is approximately 1,903 MW and of this amount, 741 MW is baseload capacity provided by the Palo Verde Nuclear Generating Station and the Four Corners Generation Station. Approximately 1,053 MW is provided by the Rio Grande Generating Station and the Newman Generating Station and is characterized as intermediate load

[4] Provisions for phased construction apply to the project and can be found at 40 CFR 52.21(j)(4) and (r).

operations. These stations are not designed for rapid startup/shutdown, which is problematic to provide reliable electricity to the service area during peak summer demand. Currently, 62 MW of peaking power is provided by the Copper Generation Station and is used to supplement high peak loads during the elevated summer temperatures as well as any unscheduled outages from the other power stations. In 2013, EPEC added approximately 89 MW of capacity with the new Rio Grande Unit 9, a GE LMS 100 unit, also tasked to peaking/intermediate service. In 2012, EPEC has added 47 MW of solar generation to the existing power system. The solar component provides a variable amount of electricity and requires a quick ramping generation to back it up. This fast ramp up capability is required for electricity generation during peak electricity demand periods and also to respond to sudden demands that can occur when renewable sources become unavailable (e.g., when solar generation tapers off in cloudy weather).

A recent wildfire event that threatened transmission from EPEC's western baseload resources, anticipated growth demand and model forecasting (PROMOD), has highlighted the need for additional capacity, especially capacity capable of serving peak loads and is a concern for EPEC. EPEC has modeled that the existing system needs additional peaking power generation to provide the flexibility to startup and shutdown units during off peak hours or at night. The anticipated demand growth curve will be matched by EPEC by adding the additional power generation capacity as a continuous construction project with each combustion turbine constructed in a sequential manner (approximately 100 MW/year). The period of time between each combustion turbines construction will not exceed 18 months.

Combustion Turbine Generator

The proposed plant will consist of four identical natural gas-fired simple cycle CTGs. The BACT analysis considers a combined cycle CTG and multiple simple cycle CTG models, the LM6000 SPRINT, FT8 TwinPac and SGT-800. Each CTG will burn pipeline natural gas to rotate an electrical generator to produce electricity. The main components of a combustion turbine generator consist of a compressor, combustor, turbine, and generator. The compressor pressurizes combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the turbine where the gases expand across the turbine blades, driving a shaft to power an electric generator. To reduce the heat level from the turbine compressor and allow for a higher mass flow of combustion air, the GE-LMS100 offers an option of two types of intercoolers, a wet system or a dry system. Montana Power Station has selected to use the wet system of intercooler, which is the more thermally efficient and thus the lower-emitting of the two designs. The wet system for Montana Power Station will require two evaporative cooling towers. The cooling towers are not a source of GHG emissions.

In 2012, renewable energy resources (other than hydroelectric) account for approximately 5 percent of the electricity generated by electric utilities[5]. The use of solar and wind power poses a variety of problems for utilities primarily due to the uncontrollability of the power source and the high degree of variability. An alternative considering renewable resources as a primary fuel was eliminated because it would be a fundamental redesign of the proposed project.

[5] U.S. Department of Energy, Energy Information Administration, *Frequently Asked Questions*. See http://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3, September 30, 2010.

Fire Water Pump

The site will be equipped with one nominally rated 327-hp diesel-fired firewater pump engine to provide water in the event of a fire. The firewater pump engine will be limited to 1 hour per week of non-emergency operation for purposes of maintenance checks and readiness testing. GHG emissions from the fire water pump will primarily consist of CO_2. The CO_2e emissions from the fire water pump engine account for less than 0.001% of the project's total CO_2e emissions.

Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

The circuit breakers associated with the proposed units and associated equipment 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 which under normal circumstances do not leak gas. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be four (4) breakers of 35 lb SF_6, 25 breakers of 64 lb SF_6, one (1) breaker of 140 lb SF_6, two (2) units of 300 lb SF_6 and two (2) breakers of 1,850 lb of SF_6. The proposed circuit breakers 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. The potential CO_2e emissions from circuit breaker SF_6 emissions account for less than 0.05% of the project's total CO_2e emissions.

Fugitive Emissions from Natural Gas Piping Components

Emissions from natural gas piping components (valves and flanges) associated with this project consist of methane (CH_4) and carbon dioxide (CO_2). Because a majority of the GHG fugitives from the natural gas piping components will be in the form of methane and the GWP is higher for methane than carbon dioxide, a conservative estimate was done by assuming that all piping components are in methane service. The potential CO_2e emissions from the natural gas piping components account for less than 0.00003% of the project's total CO_2e emissions.

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. Natural Gas Fired Simple Cycle Combustion Turbines BACT Analysis (EPNs: GT-1, GT-2, GT-3 and GT-4)

Step 1 – Identify all available control technologies

The first step in the top-down BACT process is to identify all "available" control options. In general, if a control option has been demonstrated in practice on a range of exhaust gases with similar physical and chemical characteristics and does not have a significant negative impact on process operations, product quality, or the control of other emissions; it may be considered as potentially feasible for application to another process. The following are considered as available options:

- *Carbon Capture and Storage* - Carbon capture and storage is a GHG control process 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)."[6] 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, may be applicable 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.

  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

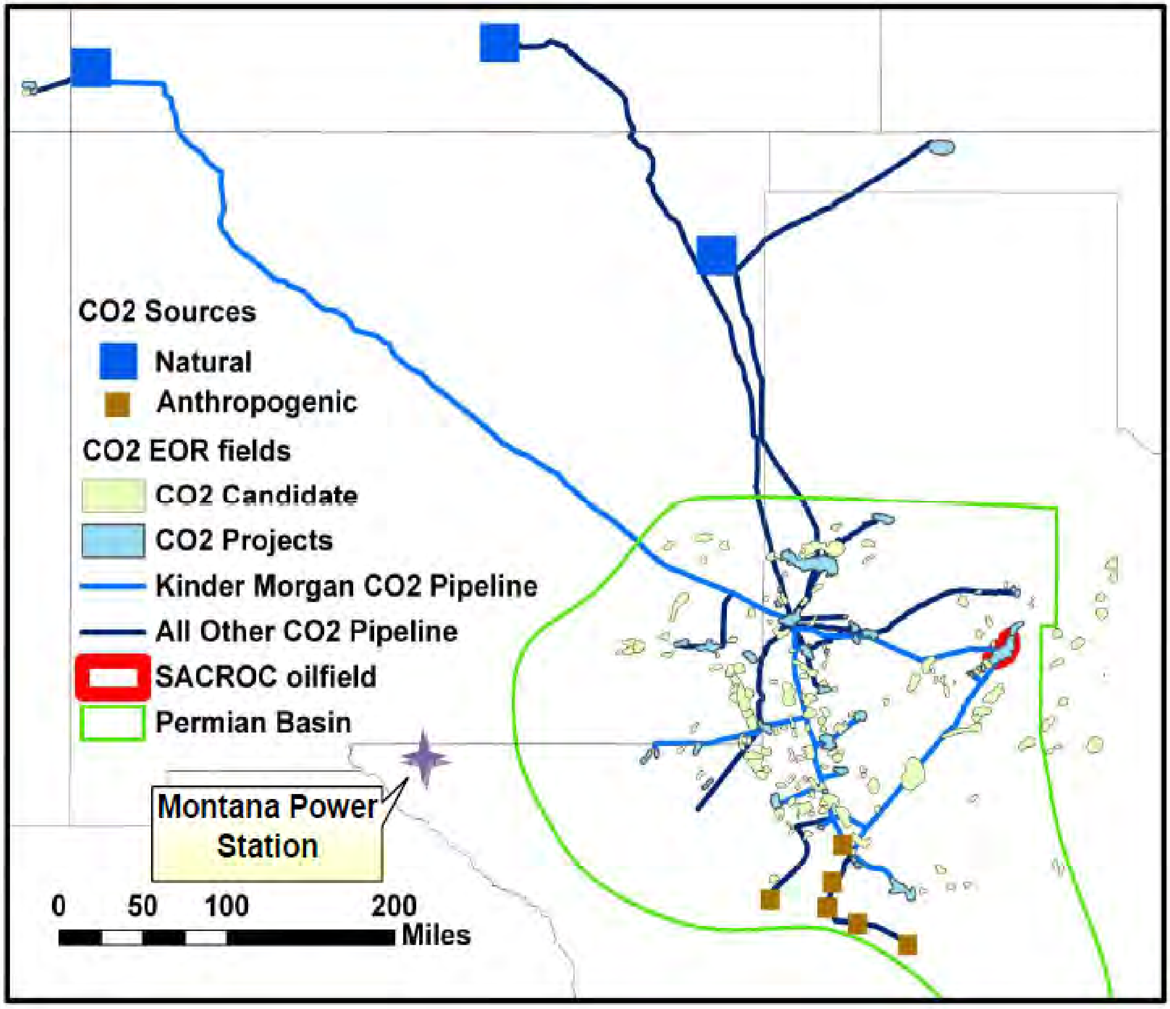
[6] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf, March 2011.

regenerated at elevated temperatures and then returned to the absorber for re-use. Fluor's Econamine FG Plus process operates in this manner, and it uses an MEA-based solvent that has been specially designed to recover CO_2 from oxygen-containing streams with low CO_2 concentrations typical of gas turbine exhaust (Fluor, 2009). This process has been used successfully to capture 365 tons per day of CO_2 from the exhaust of a natural gas combined-cycle plant owned by Florida Power and Light in Bellingham, Massachusetts. The CO_2 capture plant was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003). As this technology is commercially available and has been demonstrated in practice on a combined-cycle plant, EPA generally considers it to be technically feasible for natural gas combined cycle turbines. However, this technology has not been demonstrated in a simple cycle turbine configuration. Typically, the low concentration of CO_2 in natural gas fired turbine configurations adds to the challenge of CO_2 capture over coal fired power plants [post combustion] or integrated gasification combined cycle (IGCC) plants. The combustion turbines proposed for this project are expected to contain less than 5 percent CO_2 concentration in the flue gas exhaust. This concentration is much lower than other types of power plants, such as coal fired, where the CO_2 concentration may be as high as 12-15 percent by volume in the post combustion flue gas stream. Therefore, for natural gas-fired simple cycle combustion turbine used in a peaking load operation, operational challenges and additional equipment would be required due to the highly variable flow of low concentration of CO_2 flue gas which in turn translates to significant impacts on the power unit output, efficiency and possibly the cost of electricity.

Once CO_2 is captured and compressed from the flue gas, 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.[7] However, for purposes of this analysis, the closest area for consideration of EOR is the Scurry Area Canyon Reed Operators (SACROC) oilfield that is located near the eastern edge of the Permian Basin in Scurry, Texas. The SACROC oilfield is approximately 400 miles from the proposed Montana Power Station, see Figure 2 below.

[7] 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

Figure 2. SACROC Oil Field in Relation to the Proposed Montana Power Station



In this assumed scenario, EPEC assumed a CO_2 pipeline length of 110 miles for its analysis. This pipeline length was selected as the closest available pipeline alternative to the SACROC Oil Field. However, just because a company can recover CO_2 does not mean that the company can have a contractual customer or partner willing to purchase the CO_2. As noted in EPA's *Permitting Guidance for Greenhouse Gases,* we recognized the significant logistical hurdles that the installation and operation of a CCS system presents that sets it apart from other add-on controls that are typically used to reduce emission of other regulated pollutants such as NOx or SO_2. In this case, CCS would be an add-on control for GHGs for EOR purposes and would require a second party willing to accept and utilize the CO_2 for EOR purposes. Essentially, requiring CCS for this facility would require the applicant to clear numerous logistical hurdles such as obtaining contracts for offsite land acquisition for pipeline right-of-way, construction of the transportation infrastructure, and develop a customer(s) who is willing to purchase the CO_2.

Another tradeoff from the addition of CCS is the necessity for more water and land use. Approximately 44% more water may be needed for cooling applications using a carbon capture process. Also, additional land use would be necessary to install a CO_2 pipeline.[8]

- *Generating technologies such as combined-cycle gas turbines* – Consideration of the use of a combined cycle combustion turbine.
- *Combustion Turbine Design Efficiency* – A high efficiency design and emission unit natural gas-fired simple cycle combustion turbine.
- *Fuel Selection* – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input.
- *Good Combustion, Operating, and Maintenance Practices* – Good combustion, operating, and maintenance practices are a potential control option for improving the fuel efficiency of the combustion turbine.
- *Use of Evaporative Cooling* – Chilling the incoming air increases the thermal and power efficiency of the combustion turbine. The GE LMS 100 system is offered with two types of intercooling systems, a wet system that uses an evaporative cooling tower and a dry system that uses an air-to-water heat exchanger. An alternate dry intercooler system is being developed for future applications[9] and is not considered in this BACT analysis.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Carbon Capture and Storage:* The CCS option identified in Step 1 is considered very technically challenging for this project; however, for the purposes of this BACT analysis the CCS alternative remains under consideration.
- *Alternative generating technologies such as combined-cycle gas turbines*: The PSD and Title V Permitting Guidance for Greenhouse Gases notes that combined cycle combustion turbines, in many applications, may be more efficient than simple-cycle operations. In a typical combined cycle turbine, the use of a HRSG allows the production of more electricity without the additional fuel consumption.

  In determining the technical feasibility of a control technology, it is appropriate to consider whether the technology may reasonably be deployed on, or is applicable to, the source type under consideration. When selecting a type of generation, it is important to match the generation resource to the load in the most efficient and reliable manner possible. By shutting down when the peak demand abates, a simple cycle turbine may shut down faster than a combine cycle turbine and therefore, reduce emissions that would otherwise have occurred with the use of a combined cycle turbine that would take longer to shutdown. Screening curves specific to electric generators are developed through modeling that takes the specific facts of the generator's portfolio and historical load duration curves into account to establish the cross points where a simple cycle turbine becomes more economical than a combined cycle turbine.[10] For the EPEC

[8] Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant; September 30, 2010; DOE/NETL-403-110509; U.S. Department of Energy, National Energy Technology Laboratory
[9] Reale, Michael J., LMS100 Platform Manager, General Electric Company, *New High Efficiency Simple Cycle Gas Turbine – GE LMS100*. http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4222a.pdf, June 2004.
[10] We note that the applicant has submitted an analysis to show that the use of a combined-cycle design for the proposed project would not be cost-effective and would cause an addition adverse environmental affect; however, we are not relying on

business plan, operational flexibility is needed to respond to electricity generation demands in 10 minutes or less upon dispatch. The WECC requires an operating reserve margin with a 10-minute startup. If this cannot be achieved then there must be spinning reserves, meaning units operating at less than full load and therefore, at lower efficiencies.[11]

The start-up sequence for a combined-cycle plant includes three phases: 1) purging of the HRSG; 2) gas turbine speed –up, synchronization, and loading; and 3) steam turbine speed-up, synchronization, and loading. The third phase of this process is dependent on the amount of time that the plant has been shut down prior to being restarted; the HRSG and steam turbine contain parts that can be damaged by thermal stress and require time to heat up and prepare for normal operation. For this reason, the complete startup time for a combined-cycle plant is typically longer than that of a similarly sized simple cycle plant.[12] For example, the General Electric Company states that the GE LMS100, a simple cycle aeroderivative gas turbine, offers a fast start capability that can deliver 100 MW in 10 minutes.

Even with fast-start technology, new combined –cycle units may require up to 3½ hours to achieve full load under some conditions.[11] These longer startup times are incompatible with the purpose of the proposed project to provide a rapid response to changes in the supply and demand of electricity. An additional concern with the use of a combined-cycle configuration is the thermal mechanical fatigue due to the large numbers of startups and shutdowns. Considering the EPEC need for operational flexibility to startup and shutdown multiple times daily, the selection a combined cycle facility is technically infeasible for the purpose of the proposed project to provide power as peaking/intermediate load operation as defined by the applicant.

The remaining control options identified in Step 1 are considered technically feasible and are being proposed for Step 3 analysis.

Step 3 – Ranking of Controls

- Carbon Capture and Storage,
- Efficient Turbine Design,
- Fuel Selection,
- Good Combustion, Operating, and Maintenance Practices,
- Use of Evaporative Cooling

The efficiency of simple-cycle combustion turbines may be estimated and is considered in this analysis. Simple cycle combustion turbine efficiencies are noted to range from approximately 37% to 44% depending upon the site location and plant configuration. Fuel selection, and good combustion, operation, and maintenance practices are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, ranking is not possible.

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that analysis as we have determined that such a design is technically infeasible for the proposed project. The applicant's analysis may be found in Appendix E of the July 31, 2012 information supplement and is available in EPA's administrative record for reference.

[11] Western Electricity Coordinating Council. WECC Standard BAL-STD-002-0 – Operating Reserves. < http://www.wecc.biz/library/Documentation%20Categorization%20Files/Regional%20Standards/BAL-STD-002-0.pdf>

[12] U.S. Environmental Protect Agency, Region 9. Fact Sheet and Ambient Air Quality Impact Report for the Proposed Prevention of Significant Deterioration Permit, Pio Pico Energy Center.

Step 4 – Economic, Energy and Environmental Impacts

Carbon Capture and Storage

Numerous studies have been conducted to estimate the capital and operating costs of applying CO_2 capture technologies to fossil-fuel fired power plants. However, the existing cost studies have only been associated with natural gas-fired combined cycle or coal-fired power plants and not a natural gas-fired simple cycle power plant. EPEC developed a generalized cost estimate for CCS as an add-on control option for the proposed project and a detailed spreadsheet is available for review in the appendix to this document. EPA Region 6 reviewed EPEC's CCS cost estimate and believes it adequately approximates the cost of a CCS control for this project. The majority of the cost for CCS is attributed to the capture and compression facilities that would be required. The capital cost to construct a plant large enough to process the flue gases from the Montana Power Station is approximately $326 million. Annual costs (operating costs plus amortized capital costs) are estimated to be approximately $29 million. The estimated total cost of the project without CCS is approximately $315 million and total cost with CCS addition is approximately $641 million. Therefore, the addition of CCS would increase the total capital project costs by more than 50%, which is excessive in relation to the overall cost of the proposed project.

In addition to the cost analysis, the following is a list of the site specific safety or environmental impacts associated with a potential CO_2 removal system.

Economic Feasibility: The low purity and concentration of CO_2 in the combustion turbines' exhaust means that the per ton cost of removal and storage will be much higher than the public data estimates for much larger carbon rich fossil fuel power facilities due to the loss of economies of scale. Even using low-side published estimates for CO_2 capture and storage of $256 per ton for a new natural gas combined cycle facility, assuming a conservative $6/MBtu gas price (Anderson, S., and Newell, R. 2003. Prospects for Carbon Capture and Storage Technologies. Resources for the Future. Washington DC) means added cost to the project over $200,000,000 per year.

Energy Penalty: Published studies referenced in EPEC's Response to Completeness Determination letter dated July 31, 2012, estimate energy penalties in the range of 15% to 30% of produced energy for CCS. The Department of Energy has also reported for Natural Gas Combined Cycle plants an estimated energy loss of 15% may be realized.[13] This also means that approximately 15% - 30% more fuel will be consumed and up to an additional 15% - 30% tons of CO_2 per year will be produced. This equates to burning up to an additional 5.1 billion cubic feet of natural gas per year and producing an additional 273,407 tons of CO_2 per year just to support CCS.

Criteria Emissions Penalty: Combustion of up to 5.1 billion cubic feet of natural gas to account for the energy penalty would result in the following additional emissions on an annual basis:

- **NO_x** – 21.49 tpy
- **CO** – 31.38 tpy
- **$PM/PM_{10}/PM_{2.5}$** – 16.40 tpy
- **SO_2** – 1.64 tpy

[13] U.S. Department of Energy, National Energy Technology Laboratory, *Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant*. See: http://www.netl.doe.gov/energy-analyses/pubs/NGCC_LCA_Report_093010.pdf

- **VOC** – 6 tpy

Therefore, the cost considerations, as well as the above mentioned technical and adverse environmental challenges make CCS for this specific site and project both economically and more than likely technically infeasible. Thus, CCS has been eliminated as BACT for this project.

<u>Efficient Combustion Turbine Design</u>

Alternative simple-cycle combustion turbines that were noted in the permit application to meet the proposed project's objectives are the GE LMS100 and the Siemens 5000F. For this analysis, the efficiencies of various comparable simple cycle turbines are as follows:

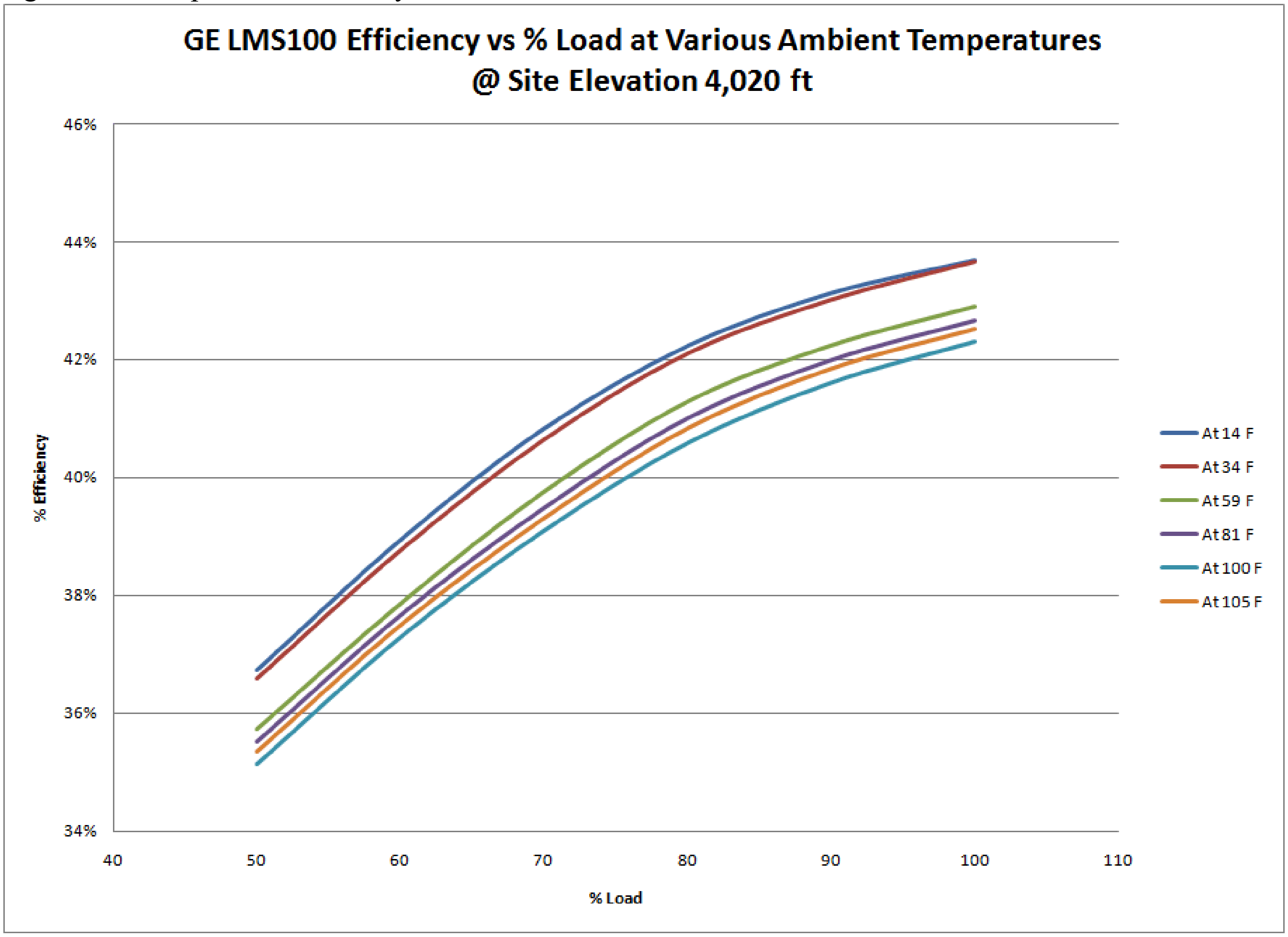
Table 1. Efficiencies of Various Comparable Simple Cycle Combustion Turbines

Simple Cycle Combustion Turbine Model	**Base Rating (MW)**	**Heat Rate (Btu/kWh, LHV)[14]**	**Efficiency (%)**
GE LMS100	100	7,937	43.6
GE LM6000PC SPRINT	50.5	8,589	40.3
Siemens 5000F	232	8,794	38.8
Siemens SGT-800	47.5	9,058	37.7
P & W FT8 TwinPac	51.4	9,214	37

It is important to note that the calculated gross gas turbine power and efficiency are as "measured" across the electric generator terminals at ISO (International Organization for Standardization) site conditions without allowances for inlet filter and duct losses, exhaust stack and silencer losses, gearbox efficiency and any auxiliary mechanical and electrical systems parasitic power consumption. ISO design ratings are typically provided to be 59°F and sea level. However, to assess site-specific gas turbine performance, correction factors should be applied. Montana Power Station has provided an efficiency curve, Figure 3, to estimate the anticipated actual operational scenario for a simple cycle combustion turbine located in El Paso Texas.[15] The efficiency has been corrected to represent the output at the site-specific elevation of 4,020 ft and the various ambient temperatures. The site specific heat rate for the GE LMS 100 at 100% load is 9,299-9,074 Btu/kWh.

[14] Heat rate values correspond to 100% load conditions at ISO conditions.
[15] Email from L. Kambham, Trinity Consultants, to M.Magee, U.S. EPA, Region 6, on June 7, 2013.

Figure 3. Site-Specific Efficiency Curve for GE LMS 100 at El Paso Texas



Simple cycle gas turbines, especially aeroderivatives, are typically used to support the electric power grid by providing quick start (10 minutes to full power) and load following capability. General Electric states that the LMS100 system is the only gas turbine in its size class with both of these capacities. It is also noted that the LMS100 can operate with very little power variation for up to 5% grid frequency variation and is uniquely capable of supporting the electric grid in times of high demand and load fluctuations. The project, if constructed and operated as proposed, would generate 400 MW (nominal gross output) of the peaking electric power at an overall project fuel efficiency of approximately 35%-37% efficiency at 50 % loading and typical ambient conditions for El Paso, Texas.

Fuel Selection

In 2008, approximately 70% of the electricity used in the United States was generated by burning fossil fuels (coal, natural gas, petroleum liquids). The combustion of a fossil fuel to generate electricity can be either: 1) in a steam generating unit (also referred to simply as a "boiler") to feed a steam turbine that spins an electric generator; or, 2) in a combustion turbine or a reciprocating internal combustion engine that directly drives the generator.[16] A fundamental design consideration is the type of fuel that is selected for combustion.

Natural gas is a fossil fuel formed when layers of buried plants and animals are exposed to intense heat and pressure over thousands of years. The energy that the plants and animals originally obtained from the sun is stored in the form of carbon in natural gas. Natural gas is combusted to generate electricity, enabling this stored energy to be transformed into usable power. At a power plant, the burning of natural gas produces nitrogen oxides and carbon dioxide, but in lower quantities than burning coal or oil. Methane, a primary component of natural gas and a greenhouse gas, can also be emitted into the air when natural gas is not burned completely. Similarly, methane can be emitted as the result of leaks and losses during transportation.[17]

EPEC proposes to utilize only natural gas as fuel for the combustion turbines.

Good Combustion, Operating, and Maintenance Practices

Good combustion, operating, and maintenance practices are a control option for improving the fuel efficiency of the combustion turbine. Natural gas-fired combustion turbines typically operate in a lean pre-mix mode to ensure effective staging of air/fuel ratios in the turbine; thus, maximizing fuel efficiency and minimizing incomplete combustion. Furthermore, the turbine's operation automated to ensure optimal fuel combustion and efficient operation leaving virtually no operator ability to further tune these aspects of operation. Good combustion practices also include proper maintenance and tune-up of the combustion turbine system at least annually per the manufacturer's specifications.

Modern combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system is a digital type and is supplied with the combustion turbine. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency, low-emissions performance.

Use of Evaporative Cooling

An evaporative cooling system will be used to cool the incoming combustion turbine air (to approximately 60°F) in order to increase the combustion air mass flow. Chilling the incoming air in this way increases the thermal efficiency and power gain of the combustion turbine, thus reducing GHG emissions. GE's LMS100 is the only natural gas fired simple cycle system that has an intercooler between the first stage of compression (a.k.a., Low Pressure Compressor (LPC)) and the second stage of compression (a.k.a., High Pressure Compressor (HPC)). This intercooling system provides for additional cooling of gases after the first stage of compression (LPC) and reduces the work of

[16] "Available and Emerging Technologies for Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units". EPA, OAR. October 2010
[17] http://www.epa.gov/cleanenergy/energy-and-you/affect/natural-gas.html

compression for the HPC, which allows for higher pressure ratios and therefore, results in higher overall efficiency. The GE LMS100 offers an option of two types of intercoolers, a wet system or a dry system. EPEC notes that a dry-cooled LMS100 in El Paso would lose at least 10 percent of its maximum rated capacity in the peak summer months, which is precisely when the additional power generation would be needed most. Additionally, EPEC has stated that the dry-cooling systems would impose a higher parasitic load and would reduce the net power output available to the grid by approximately 1 percent. For these reasons, EPEC has elected to use the wet system of intercooler to take advantage of the additional cooling achieved by that system. In addition, EPEC has a signed agreement with the El Paso Water Utility for the water that will be provided for the cooling system and other facility operations.

Step 5 – Selection of BACT

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

Table 2: GHG BACT Limits for Other Similar Facilities

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Cheyenne Light, Fuel & Power / Black Hills Power, Inc. Laramie County, WY	Simple cycle combustion turbine	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit of 1,600 lbs CO_2e/MWhr (gross) 365-day average, rolling daily	2012	PSD-WY-000001-2011.001
York Plant Holding, LLC Springettsbury Township, PA	Simple cycle combustion turbine	Energy Efficiency/ Good Design & Combustion Practices	Combustion turbine annual net heat rate limited to 11,389 Btu/kWh (HHV) when firing natural gas GHG BACT limit of 1,330 lb CO_2e/MWhr (net) when firing natural gas 30-day rolling average	2012	67-05009C*
Pio Pico Energy Center, LLC Otay Mesa, CA	300 MW simple cycle power plant	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit of 1,328 lb CO_2e/MWhr (gross) 720 rolling operating-hour average	2012	SD 11-01

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
LADWP Scattergood	Simple cycle combustion turbine	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit of 1,260 lb CO_2e/MWhr (net) 12-month rolling average	2013	800075

EPA has concluded that the GHG BACT for Montana Power Station is the use of new natural gas fired, thermally efficient simple-cycle combustion turbines combined with evaporative cooling at the turbine air inlet and between the low- and high-pressure compressors (by the intercooler) and good combustion and maintenance practices to maintain optimum efficiency. EPA believes that the applicant's proposal to use the GE LMS100 is consistent as a BACT requirement. Based on these factors and data provided to EPEC from GE Power & Water, EPA is proposing a heat rate limit of 4,292,750 MMBtu/yr (HHV), per combustion turbine, on a 12-month rolling basis. This limit is based on the maximum hourly heat rate of 858.55 MMBtu/hr (HHV), 5,000 hours of operation per year, and 100 percent load, for each combustion turbine. Each combustion turbine is limited to 5,000 hours of operation (including startups and shutdowns). Limiting the fuel use achieves the same objective as limiting the number of hours of operation of each turbine to 5,000 hours. Therefore, the hours of operation limit that is proposed is 5,000 hours and includes the time associated with startup and shutdown. The annual CO_2e emission limit is based on 5,000 hours of operation at 100% load. The unburned methane emissions during the startup and shutdown operations are estimated for 832 startup and 832 shutdown events.

In addition, EPA proposes to establish an emission limit of 1,194 lb CO_2/MWhr (gross) output on a 5,000 operational hour rolling basis. This limit reflects the site specific parameters anticipated by the facility and the maximum allowable utilization of the combustion turbines in peaking/intermediate dispatch. The operating scenario provided by the applicant (5,000 operational hours at 50 percent load per year) was used to calculate the worst-case efficiency, and maximum CO_2/MWhr (gross), for the combustion turbines.

The Montana Power Station BACT limit of 1,194 lb CO_2/MWhr (gross) is lower than the other recently issued GHG BACT limits. The Pio Pico Energy Center initially proposed a BACT limit of 1,181 lb CO_2/MWhr (net); however, the limit was changed to 1,328 lb CO_2/MWhr (gross) based on a response to comments. For additional comparison purposes, the Montana Power Station GHG BACT proposed limit when converted from gross to net power output is approximately 1,210 lb CO_2e/MWhr (net). Net output generation is a measurement of the energy available minus the output consumed in any way related to the generation. Typically, the net output of a unit is less than the expected gross output of a unit. For the Montana Power Station project, the difference between gross and net power output from the GE LMS100s will average 1.3 percent over the anticipated operating loads and ambient conditions. The analysis for Montana Power Station was completed on the basis that natural gas would be used as the fuel and the turbine would be operated at a conservative range of dispatch scenarios over a 12-month averaging period (i.e., as low as 50 percent loading for 5,000 hours of operation).

Additionally, as shown in Figure 1 of this document, the efficiency of the GE LMS100 operating in El Paso Texas will be less than a similar unit operating in different ambient conditions. Due to the variation in elevation and ambient temperature, the GE LMS100 installed in El Paso Texas will not be quite as efficient as a GE LMS100 installed in Otay Mesa, California (Pio Pico Energy Center location), which will experience lower altitudes and temperatures and higher humidity (generally more favorable for efficient operation), even assuming identical dispatch. Even with the difference in environmental conditions in El Paso, Texas and the expected dispatch (i.e., loads) of the combustion turbine, the BACT limit for EPEC is set as 1,194 lb CO_2/MWhr (gross) on 5,000 hours of operation rolling basis for the Montana Power Station and is lower than the other recently issued permits.

BACT During Startup and Shutdown

BACT applies during all periods of turbine operation, including startup and shutdown. The number of startups and shutdowns is based on the number of operational hours per year (5,000 service hours per year per turbine). All startups are limited to 10 minutes in duration. A startup of each turbine is defined as the period that begins when there is measureable fuel flow to the turbine and ends when the turbine load reached 50 percent. The proposed Montana Power Station project is proposing 832 startups with corresponding shutdowns for 5,000 operational hours per year per turbine. For comparison purposes, the recently issued PSD permit for the Pio Pico Energy Center requested 500 startups with corresponding shutdowns per year and 4,000 operational hours per year per turbine. Adjusting the Pio Pico Energy Center calculations to the same methodology used by Montana, the number of startup/shutdowns for Pio Pico Energy Center would be 625 events. Considering the additional 1,000 operational hours and more extreme weather events for the El Paso Texas area, the additional startup and corresponding shutdown events for the Montana Power Station project appear to be proportional to the Pio Pico Energy Center project. BACT for startup/shutdown is the work practice standard to utilize good pollution control practices, safe operating practices and protection of the facility. The startup /shutdown emissions shall be minimized by limiting the duration of operation in startup/shutdown mode and the number of startup and shutdown events as follows:

- Startups and shutdowns are limited to no more than 10 minutes per event.
- No more than 832 startup and corresponding shutdown events per turbine on a 12-month rolling basis.

BACT Compliance:

BACT for each combustion turbine is 1,194 lb CO_2/MWh (gross). Compliance will be based on a 5,000 operational hour rolling basis, calculated daily for each turbine. EPEC will maintain records of tune-ups, and maintenance records for each combustion turbine. In addition, records of fuel temperature, and stack exhaust temperature will be maintained for each combustion turbine. For each combustion turbine, the parameters that will be measured are natural gas flow rate using an operational non-resettable elapsed flow meter, total amount of fuel combusted on an hourly basis, fuel gross calorific value (GCV) on a high heat value (HHV), carbon content, combustion temperature, exhaust temperature, and gross hourly energy output (MWh).

To determine compliance with the annual CO_2e emission limit, EPEC will calculate, on a daily basis, the amount of CO_2e emitted from each turbine in tons per year for the trailing 365-day period based on the measurement of the CO_2 CEMS and the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395) for CH_4 and N_2O. Compliance shall be based on a 365-day rolling basis. The CO_2

emissions used for the calculation of the annual CO_2e emission limit is based on a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions. The CH_4 and N_2O emissions are based on the measured quantity of fuel used by each turbine.

Based on the CO_2 CEMS measurement, EPEC shall calculate, each day a combustion turbine operates, the CO_2 emission on a 5,000 operational hour rolling basis divided by the gross electrical output over the same period operational time period for comparison to the limit of 1,194 lbs of CO_2/MWhr (gross) output for each combustion turbine.

For any period of time that the CO_2 CEMS is nonfunctional, the permittee shall use the methods and procedures outlined in the Missing Data Substitution Procedures as specified in 40 CFR Part 75, Subpart D.

An initial stack test demonstration will be required for CO_2 emissions from each emission unit. The combustion turbine GHG emissions primarily consist of CO_2. The CO_2 emissions account for 99.9% of the GHG emissions from each turbine. For each combustion turbine, within 60 days after achieving the maximum production rate at which the affected turbine will be operated, but not later than 180 days after initial startup of the turbine, an initial performance test must be conducted and provided to the EPA. The CO_2 emission testing shall be performed every five years, please or minus six months, of when the previous performance test was performed, or within 180 days after the issuance of a permit renewal, whichever comes later to verify continued performance at permitted emission limits.

An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the CT and are considered a *de minimis* level in comparison to the CO_2 emissions.

IX. Fire Water Pump BACT Analysis (EPN: FWP-1)

The Montana Power Station will be equipped with one nominally rated 327-hp diesel-fired pump engine to provide water in the event of a fire.

Step 1 – Identification of Potential Control Technologies

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

Step 2 – Elimination of Technically Infeasible Alternatives

- *Low Carbon Fuels* – The purpose of the engine is to provide a power source during emergencies, which includes outages of the combustion turbines, natural gas supply outages, and natural disasters. Electricity and natural gas may not be available during an emergency and therefore cannot be used as an energy source for the emergency engine and are eliminated as technically infeasible for this facility. The engine must be powered by a liquid fuel that can be stored on-site in a tank and supplied to the engines on demand, such as gasoline or diesel. Gasoline fuel has a much higher volatility than diesel, and is thus less safe for use in an emergency situation, and it cannot be stored for long periods of time, which may be necessary for emergency use. Therefore, gasoline is eliminated as infeasible for these emergency engines.

- *Good Combustion Practices and Maintenance* – Is considered technically feasible
- *Low Annual Capacity Factor* – Is considered technically feasible since the engines will only be operated either for readiness testing or for actual emergencies.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

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

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

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the diesel-fired Fire Water Pump:

- *Good Combustion Practices and Maintenance* – Good combustion practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air to fuel ratio, as specified by its design.
- *Low Annual Capacity Factor* – The emergency engine will not be operated more than 1hour per week. They will only be operated for maintenance and readiness testing, and in actual emergency operation.

Using the BACT practices identified above results in a BACT limit of 8.69 tpy CO_2e for the Fire Water Pump (FWP-1. EPEC will demonstrate compliance with the CO_2 emission limit using the default emission factor and default high heating value for diesel fuel from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = 1 \times 10^{-3} * Fuel * HHV * EF * 1.102311$$

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

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV). The engine shall meet the requirements of 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

X. Fugitive Emissions from SF_6 Circuit Breakers BACT Analysis (EPN: CTBR-SF6)

The circuit breakers associated with the proposed units will be insulated with SF_6. The total SF_6 inventory of the circuit breakers will not exceed 6,180 lb.

Step 1 – Identification of Potential Control Technologies for GHGs

In comparison to older SF_6 circuit breakers, modern circuit breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning SF_6 has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

One alternative considered in this analysis is to substitute another non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NTIS) Technical note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6.*[18]

Step 2 – Elimination of Technically Infeasible Alternatives

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

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

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

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.

[18] 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

Step 5 – Selection of BACT

State-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection is the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.06 and C37.010 standard for high voltage circuit breakers.[19] The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF_6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to the lack of "quenching and cooling" SF_6 gas.

BACT compliance will be demonstrated by EPEC through annual calculation of emissions in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmissions and Distribution Equipment Use.[20] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

XI. Fugitive Emissions from Natural Gas Piping Components BACT Analysis (EPN: FUG-1)

Emissions from natural gas piping components (valves and flanges) associated with this project consist of methane (CH_4) and carbon dioxide (CO_2). Because a majority of the GHG fugitives comes from methane and the GWP is higher for methane, a conservative estimate of CO_2e emissions was done by assuming that all piping components are in pure methane service. The CO_2e from fugitive emissions associated with the natural gas piping account for less than 0.00003% of the project's total CO_2e emissions.

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, for gas processing and chemical plants. Quarterly monitoring with an instrument and a leak definition of 500 ppm is assigned as a control effectiveness of 97%. Texas' LDAR program, 28LAER, provides for 97% control credit for valves, flanges, and connectors.

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

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.[21]

AVO monitoring is effective due to the frequency of observation opportunities. It is 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 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 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 28LAER or a comparable remote sensing program when not otherwise required, these methods are not economically practicable for GHG control from components in natural gas service.

Step 5 – Selection of BACT

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

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 is relying on a Biological Assessment (BA) prepared by the El Paso Electric Company ("EPEC") and its consultant, SWCA Environmental Consultants ("SWCA") and reviewed and adopted by EPA.

A draft BA has identified ten (10) species listed as federally endangered or threatened in El Paso County, Texas:

Federally Listed Species for El Paso County by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks	**Scientific Name**

[21] 73 FR 78199-78219, December 22, 2008.

and Wildlife Department (TPWD)	
Birds	
Mexican Spotted Owl Southwestern Willow Flycatcher Western Yellow-billed Cuckoo Northern Aplomado Falcon Interior Least Tern	*Strix occidentalis lucida* *Empidonax trailii extimus* *Coccyzus americanus occidentalis* *Falco femoralis septentrionalis* *Sterna antillarum athalassos*
Mammals	
Black Bear Black-footed ferret Gray Wolf	*Ursus americanus* *Mustela nigripes* *Canis lupus*
Fish	
Rio Grande Silvery Minnow	*Hybognathus amarus*
Plants	
Sneed's Pincushion Cactus	*Coryphantha sneedii var. sneedii*

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

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.

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 its final determination, EPA has relied on and adopted an August 29 2013 cultural resource report prepared by SWCA.

The Area of Potential Effect (APE) was determined to be approximately 505 acres of land that consists of two parcels of land (166.29 acres and 88.61 acres), where construction of the facility will take place, and proposed water and transmission line corridors (250.1 acres). SWCA conducted a field survey of the APE and desktop review within a 1.0-mile radius of the project area. The desktop review included an online database search of records from the Texas Historical Commission and Texas Archaeological Research Laboratory (TARL). Based on the desktop review, one hundred and twenty-eight (128) archaeological sites were identified; eighty-nine (89) are potentially eligible for listing in the National Register. Based on the results of the field survey of the APE, two newly recorded sites and three previously recorded sites were identified. The two new archaeological sites were discovered within the right-of-way of one of the proposed transmission line corridors of the project site. One of these new sites was identified as a prehistoric campsite having Prehistoric and Native American significance and was recommended to the State Historic Preservation Officer (SHPO) to be eligible for listing on the National Register.

On August 1, 2013 and August 23, 2013, EPA sent letters to the Indian tribes identified by the Texas Historical Commission and the National Native American Graves Protection and Repatriation Act (NAGPRA) Online Database as having historical interests in El Paso County, Texas to inquire whether any of the tribes were interested in consulting with EPA in the Section 106 process. EPA has invited thirty-one tribes to participate in an informational exchange calls about the project as a follow up to the letters sent. EPA will consult with any tribes interested prior to making a final determination of effect.

Because EPA is in the process of communicating with tribes and may engage in consultation with tribes should they raise any specific issues about the area that are of interest to the tribe, EPA is only making a preliminary determination that issuance of the permit to El Paso Electric will not affect properties on or eligible for listing on the National Register based on the information contained in the draft cultural resource report.

At the completion of any consultations, EPA will make a final determination and will seek concurrence from the State Historic Preservation Officer and any consulting party with its determination of effect. Issuance of this permit will not be finalized until all obligations under Section 106 of the NHPA have been met and approved by the EPA with concurrence(s).Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic or culturally significant resources. A copy of the 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 EPEC, 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 EPEC a PSD permit for GHGs for the Montana Power Station, 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

Table 1. Annual Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
GT-1 GT-2 GT-3 GT-4	GT-1 GT-2 GT-3 GT-4	Natural Gas Fired-Simple Cycle Turbine, each	CO_2	250,885.25[3]	251,147.64[3]	-BACT limit of 1,194 lb CO_2/MW-hr (gross). -Not to exceed 5,000 hours of operation on a 12-month rolling basis per turbine. -See permit condition III.A.2 and 4.
			CH_4	5.51[3]		
			N_2O	0.47[3]		
FWP-1	FWP-1	Firewater Pump Engine	CO_2	8.66	8.69	- Not to exceed 52 hours of non-emergency operation on a 12-month rolling basis - Use of Good Combustion Practices. See permit condition III.B.
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
CTBR-SF-6	CTBR-SF-6	Fugitive SF_6 Circuit Breaker Emissions	SF_6	0.015	358.50	Work Practices. See permit condition III.C.
FUG-1	FUG-1	Components Fugitive Leak Emissions	CH_4	0.15	3.15	Implementation of AVO Program. See permit condition III.D.
Totals[5]			CO_2	1,003,549.66	**1,004,960.90**	
			CH_4	22.19		
			N_2O	1.89		
			SF_6	0.015		

1. 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. All emissions are expressed in terms of short tons.
2. Global Warming Potentials (GWP): CO_2=1, CH_4 = 21, N_2O = 310, SF_6=23,900
3. The GHG Mass Basis TPY limit and the CO2e TPY limit for the natural gas fired simple cycle turbines applies to each turbine and is not a combined limit.
4. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.

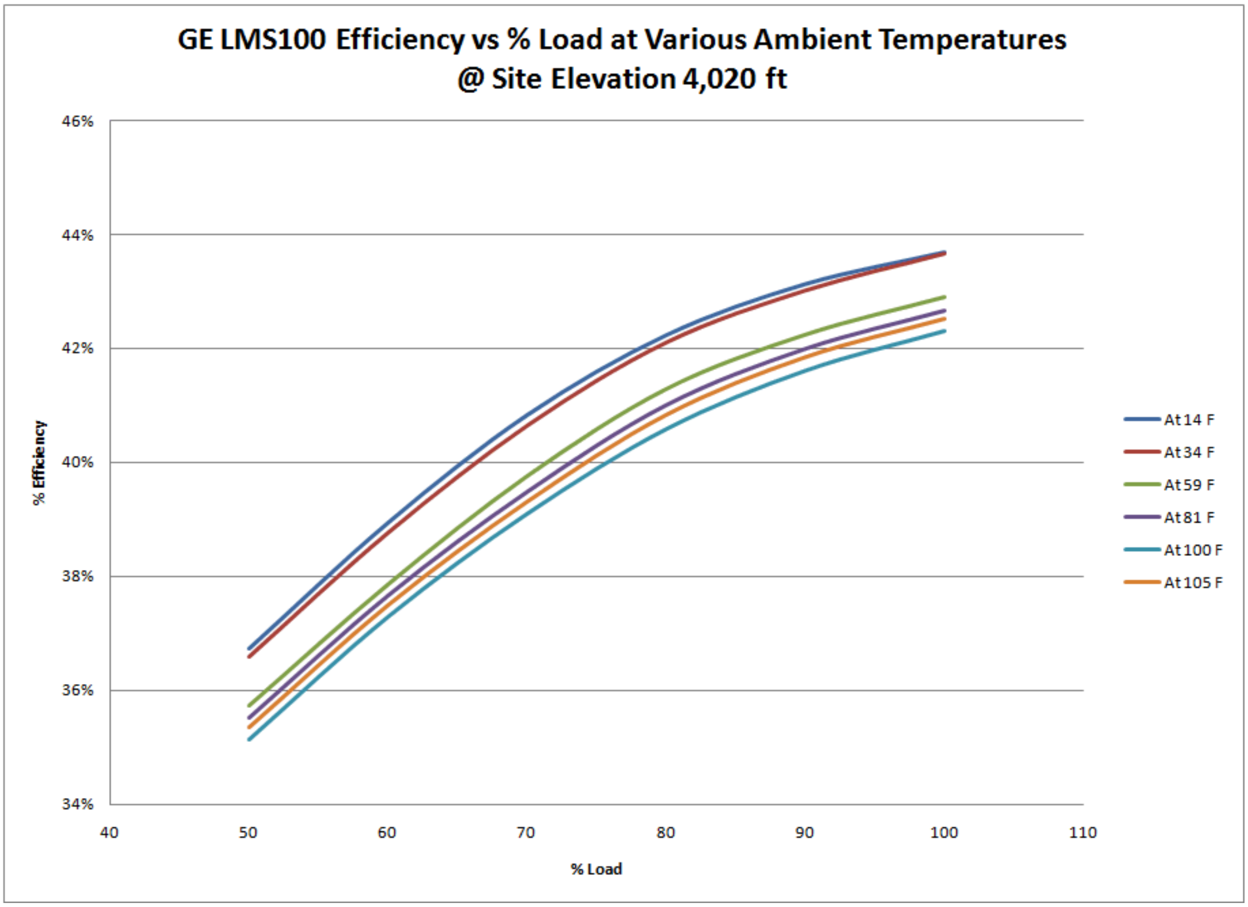
From:	Latha Kambham
To:	Magee, Melanie
Cc:	Roger.Chacon@epelectric.com ; Paul Greywall
Subject:	Status of the El Paso Electric Permit Application and Efficiency Curves
Date:	Friday, June 07, 2013 12:45:15 PM

Melanie,

Per your request, please find attached the efficiency curve at partial loads (between 50% and 100%) for the proposed Montana Power Station LMS100s at various ambient temperatures, based on the site-specific elevation of 4,020 ft for the Montana Power Station.

Please confirm that this is the only piece of information required to complete the permit application review and that there are no other outstanding items. We would like to set up a conference call with you to discuss the status of the draft permit. This afternoon or Monday morning would be great.

Also, please let us know of the timeline to issue a preliminary internal Draft GHG permit for our review.



Thanks,
Latha

****
Latha Kambham, Ph.D. | Senior Consultant | lkambham@trinityconsultants.com
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Office: (972) 661-8100 | Fax: (972) 385-9203
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Cost Estimation for Transfer of CO_2 via Pipeline

CO_2 Pipeline and Emissions Data

Parameter	Value	Units
Minimum Length of Pipeline	110	miles
Average Diameter of Pipeline	8	inches
CO_2 emissions from vents	903,187.00	tons/year
CO2 capture efficiency	90%	
Captured CO_2	812,868.30	tons/year

CO_2 Transfer Cost Estimation[1]

Cost Type	Units	Cost Equation	Cost ($)
Pipeline Costs			
Materials	$ Diameter (inches), Length (miles)	$70,350 + $2.01 x L x (330.5 x D^2 + 686.7 x D + 26,920)	$11,913,704.16
Labor	$ Diameter (inches), Length (miles)	$371,850 + 2.01 x L x (343.2 x D^2 + 2,074 x D + 170,013)	$46,486,632.78
Miscellaneous	$ Diameter (inches), Length (miles)	$147,250 + $1.55 x L x (8,417 x D + 7,234)	$12,861,435.00
Right of Way	$ Diameter (inches), Length (miles)	$51,200 + $1.28 x L x (577 x D + 29,788)	$4,895,283.20
Other Capital			
Gas Treatment Equipment and Labor[2]	$	$340,000,000.00	$340,000,000.00
Operation & Maintenance (O&M)			
Pipeline Fixed O&M per Year[1]	$	$8,454 x L	$929,940.00
		Total CCS Cost	$417,086,995.14

Amortized CCS Cost

Equipment Life (years)[2]	20
Interest rate	0.07
Capital Recovery Factor (CRF)[3]	0.094
Total Capital Investment (TCI)	$416,157,055.14
Amortized Installation Cost (TCI*CRF)	$39,118,763.18
Total CCS Annualized Cost	$40,048,703.18
Total Annualized cost/ton CO_2	$49.27

Amortized Project Cost (without CCS)

Equipment Life	20
Interest rate	0.07
Capital Recovery Factor (CRF)[3]	0.094
Total Capital Investment (TCI)	$311,000,000.00
Amortized Installation Cost (TCI*CRF)	$29,234,000.00
Total Project Annualized Cost	$29,234,000.00

[1] Cost estimation guidelines obtained from "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-2013/1614

[2] Cost for capture and gas treatment obtained from Report of the Interagency Task Force of Carbon Capture and Storage (August 2010) for

[3] Capital Recovery Fraction = Interest Rate x (1+ Interest Rate) ^ Pipeline Life) / ((1 + Interest Rate) ^ Pipeline Life - 1)

[4] This cost estimation does not include capital and O&M costs associated with the compression equipment or processing equipment

From:	Paul Greywall
To:	Magee, Melanie
Cc:	Melissa Dakes; Latha Kambham; Chacon, Roger
Subject:	Montanan Power Station - Follow up
Date:	Friday, August 23, 2013 11:28:08 AM
Attachments:	LMS100 SUSD Hours (2013-0823).xlsx

Melanie,

Attached is a table listing the permitted SUSD events for the LMS100 projects which were referenced in the contested case hearing for the Montana Power Station TCEQ PSD permit.

Regarding the water supply for the Montana Power Station, we have confirmed that El Paso Electric has a signed contract/agreement with EPWU/PSB for the water that will be provided for the cooling system and other facility operations.

We can discuss the thought process behind the selection of wet versus dry cooling for the Montana Power Station when you have time. We will also add a few sentences regarding the selection of the cooling system to our comments on the draft SOB.

Summary of SUSD Hours Permitted for LMS100 Units

Facility	Location	Permitted per LMS100 Unit hrs/yr	No. SUSD/yr	SU Duration	Note
Panoche Energy Center (Approved: December 19 2007)	San Joaquin Valley, CA (Fresno County)	5,000	365	30	1
Walnut Creek Energy Park (Approved: February 27, 2008)	South Coast, CA (Los Angeles County)	2,760	350	35	2, 6
Sentinel (Approved: December 1, 2010)	South Coast, CA (Riverside County)	3,554	350	25	3
Haynes Generating Station (Title V Permit Approved: December 29, 2010)	South Coast, CA (Los Angeles County)	8,760	1800 (150/month)	25	4
Pio Pico Energy Center (Approved: September 21, 2012)	South Coast, CA (San Diego County)	4,330	500	30	5
Proposed Montana Power Station	El Paso County, TX	5,000	832	10	7

1 http://www.energy.ca.gov/sitingcases/panoche/documents/others/2007-07-19_SJVAPC_FINAL_NOTICE_OF_COMPLIANCE.PDF
2 http://www.energy.ca.gov/sitingcases/walnutcreek/documents/government/2006-10-31_SCAQMD_PDOC.PDF
3 http://www.energy.ca.gov/2010publications/CEC-800-2010-016/CEC-800-2010-016-CMF.PDF
4 http://yosemite.epa.gov/R9/air/EPSS.NSF/[illegible]/$FILE/LA%20DWP%20Haynes%20Minor%20Revision%20Draft%20Permit.pdf
5 http://www.energy.ca.gov/2012publications/CEC-800-2012-003/CEC-800-2012-003-CMF.pdf
6 http://www.arb.ca.gov/research/apr/reports/ab-1318-south-coast-air-basin-electricity-needs-assessment-phase1.pdf
http://www.energy.ca.gov/sitingcases/alphabetical.html
7 For the proposed Montana Power Station, startup duration of 10 minutes is applicable to GHG emissions only and a separate startup duration applies to criteria pollutants.