Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Lon C. Hill Power Station

Permit Number: PSD-TX-1380-GHG

September 2014

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

I. Executive Summary

On November 7, 2013, Lon C. Hill, LP (LCH) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for greenhouse gas (GHG) emissions for a proposed construction project. On February 28, March 19, 20, 25, 28, and August 14, 2014, LCH submitted additional information for inclusion into the application. In connection with the same proposed construction project, LCH submitted an application for a PSD permit for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ). LCH proposes to construct a new natural gas-fired combined-cycle electric generating plant, the Lon C. Hill Power Station (LCHPS), to be located in Corpus Christi, Nueces County, Texas. The LCHPS will consist of two natural gas-fired combustion turbines, each exhausting to a heat recovery steam generator (HRSG) to produce steam to drive a shared steam turbine. After reviewing the application, EPA Region 6 has prepared the following SOB and draft air permit to authorize construction of air emission sources at the LCHPS.

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 permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that LCH’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 requested by EPA and provided by LCH, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

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III. Permitting Authority

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

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

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
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IV. Facility Location

The LCHPS will be located in Nueces County, Texas, and this area is currently designated “near nonattainment” for all criteria pollutants. The nearest Class I area is the Big Bend National Park, which is located well over 100 miles from the site. The geographic coordinates for this proposed facility site are as follows:

Latitude: 27° 50’ 47.11” North
Longitude: -97° 36’ 52.97” West

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

Figure 1. Lon C. Hill Power Station Location

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

EPA Region 6 implements a GHG PSD FIP for the State of Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305. On June 23, 2014, the United States Supreme Court issued a decision addressing the application of stationary source permitting requirements to GHGs. *Utility Air Regulatory Group v. Environmental Protection Agency* (No. 12-1146). The Supreme Court said that EPA may not treat GHGs as an air pollutant for purposes of determining whether a source is a major source required to obtain a PSD or Title V permit. The court also said that EPA could continue to require that PSD permits that are otherwise required based on emissions of conventional pollutants contain limitations on GHG emissions based on the application of Best Available Control Technology (BACT). Pending further EPA engagement in the ongoing judicial process before the United States Circuit Court of Appeals for the D.C. Circuit, EPA is proposing to issue this permit consistent with EPA's understanding of the Supreme Court's decision.

The proposed LCHPS is within a major facility category and is subject to a 100 TPY threshold for classification as a PSD major stationary source. The source is a major stationary source because the facility has the potential to emit CO and NOx above the applicable 100 TPY threshold. In this case, the applicant represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, has determined the applicant is subject to PSD review for the conventional regulated NSR pollutants CO, NOx, VOC, $PM_{2.5}$ and PM_{10}.

The applicant also estimates for the 2x2x1 operational configuration that this same project has the potential to emit 2,517,468 TPY CO_2e of GHGs, which exceeds the GHG thresholds in EPA regulations. 40 C.F.R § 52.21(49)(iv); see also, *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011 at 12-13). Since the Supreme Court recognized EPA's authority to limit application of BACT to sources that emit GHGs in greater than *de minimis* amounts, EPA believes it may apply the 75,000 tons per year threshold in existing regulations at this time to determine whether BACT applies to GHGs at this facility.

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

EPA Region 6 proposes to follow the policies and practices reflected in EPA's PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011). For the reasons described in that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA believes that compliance with the

BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has regulated NSR pollutants that are non-GHG pollutants, which are addressed by the PSD permit to be issued by TCEQ.

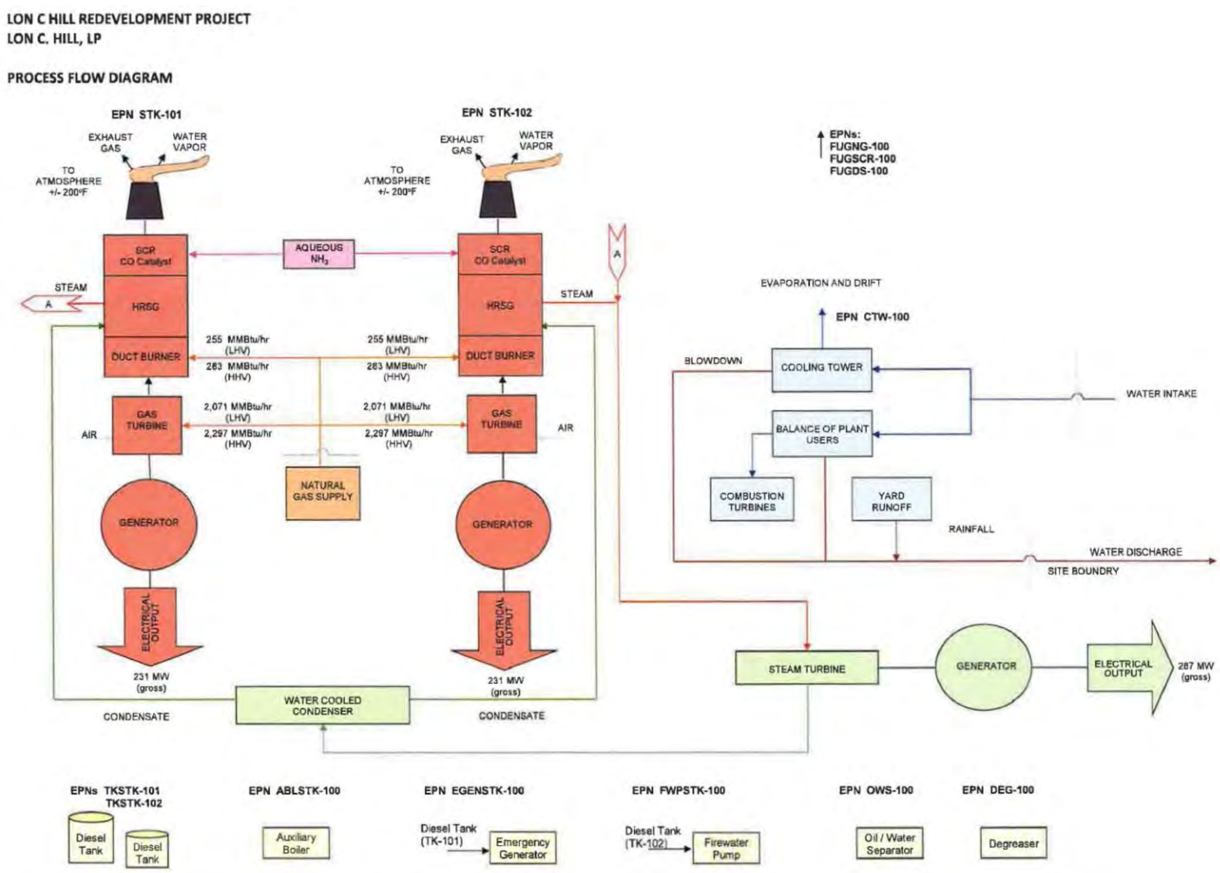
VI. Project Description

The proposed GHG PSD permit, if finalized, would authorize LCH to construct a new combined-cycle electric generating plant, the LCHPS, in Nueces County, Texas. The LCHPS will be designed to generate from 625 to 740 megawatts (MW) of gross electrical power, depending on operational plant configuration, to serve customers in the City of Corpus Christi in an efficient manner while increasing the reliability of the electrical supply for the State of Texas. The gross electrical power output is based on one combustion turbine, for the 1x1x1 configuration, or two combustion turbines for the 2x2x1 configuration rated between 195 and 240 MW each and the steam from the HRSGs driving a steam turbine is expected to generate approximately 230 to 290 MW. The LCHPS will consist of the following sources of GHG emissions:

- Two natural gas-fired stationary combustion turbines (2 combustion turbines, 2 heat recovery steam generators, and 1 steam turbine) equipped with lean pre-mix low-NOx combustors;
- Two natural gas-fired HRSG’s equipped with duct burner systems;
- Natural gas piping and metering;
- One diesel fuel-fired emergency generator engine;
- One diesel fuel-fired fire water pump engine;
- One natural gas-fired auxiliary boiler; and
- Electrical equipment insulated with sulfur hexafluoride (SF_6).

Process Description and Process Flow

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



<u>Combustion Turbine Generator</u>

In general, the main components of a combustion turbine are a compressor, combustor, turbine, and generator. The compressor pressurizes combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the turbine where the gases expand across the turbine blades, driving a shaft to power an electric generator. The exhaust gas will exit the combustion turbine generator (CTG) and is routed to the HRSG for steam production.

The new facility will consist of either two new natural gas-fired Siemens SGT6-5000F CTG, GE 7FA.04 or equivalently rated turbines. The Siemens SGT6-5000, GE 7FA.04 or equivalently rated combustion turbines will have a maximum heat consumption of approximately 2,260 MMBtu/hr (HHV) each and a nominal capacity of up to 240 MW of power each. The proposed CTG will be equipped with inlet air filtration system and either an inlet chilling system or an evaporative cooling system to pre-treat the combustions air.

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

LCH hopes to be using “pipeline natural gas” as defined in 40 CFR § 72.2 for this facility. However, for the purpose of calculating emissions for evaluation of this permit application LCH used the values as defined by “natural gas” as defined in 40 CFR § 72.2.

<u>Heat Recovery Steam Generator with Duct Burners</u>

Heat recovered in the HRSG will be utilized to produce steam. Steam generated within the HRSG will be utilized to drive a steam turbine and associated electrical generator. The HRSG will be equipped with duct burners for supplemental steam production. The duct burners will be fired with natural gas. The maximum firing rate of each duct burner system will range from approximately 250 to 670 MMBtu/hr. The duct burners’ total annual firing will not exceed the equivalent of 4,375 hours. The exhaust gases from the unit, including emissions from the CTG and the duct burners, will exit through a stack to the atmosphere through one common dedicated stack.

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

<u>Inlet Air Cooling</u>

The inlet air to the new combustion turbine will be cooled during high ambient temperature conditions through the use of evaporative cooler or an inlet chilling system. Cooling of the inlet air will increase output of the combustion turbines while lowering the heat rate.

<u>Power Generation Overall</u>

Steam produced by each of the two HRSGs will be routed to the steam turbine. The two combustion turbines and one steam turbine will be coupled to electric generators to produce electricity for sale to the Electric Reliability Council of Texas (ERCOT) power grid. Each combustion turbine model has an approximate maximum base-load electric power output up to an output of 240 MW. The steam turbine is expected to generate approximately 230 to 290 MW. The units may operate at reduced load to respond to changes in system power requirements and/or stability.

Auxiliary Boiler

The design of the new facility may include a natural gas-fired auxiliary boiler (EPN: ABLSTK-100) to provide pre-warming steam to the steam turbine prior to startup. Use of the auxiliary boiler will decrease the amount of time the combustion turbines must be run at low load levels during startup, particularly during cold startups. The unit will have a maximum heat input of 95 MM Btu/hr. The auxiliary boiler will be permitted to run no more than 500 hours annually.

Emergency Equipment

The site may be equipped with one nominally rated 1,341-hp diesel-fired emergency generator (EPN: EGENSTK-100) to provide electricity to essential ancillary equipment in case of power failure. A nominally rated 617-hp diesel-fired pump (EPN: FWPSTK-100) may be installed at the site to provide water in the event of a fire. Each emergency engine will be limited to 100 hours of operation per year for purposes of maintenance checks and readiness testing.

Natural Gas/Fuel Gas Piping

Natural gas will be delivered to the site via pipeline. Gas will be metered and piped to the new combustion turbines and duct burners. Fugitive emissions (EPN: FUGNG-100) from the gas piping components associated with the new CTG/HRSG units will include emissions of methane (CH_4). The LCHPS will emit small amounts of GHGs from gaseous fuel venting during turbine shutdown and maintenance from the fuel lines being cleared of fuel. The LCHPS will also emit small amounts of GHGs from the repair and replacement of small equipment.

Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

The generator circuit breakers associated with the proposed units will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, and non-toxic synthetic gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be 75 lbs of SF_6. The proposed circuit breaker at the generator output will be equipped with a low pressure alarm and a low pressure lockout. The alarm will alert operating personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of “quenching and cooling” SF_6 gas.

VII. General Format of the BACT Analysis

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

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

VIII. Applicable Emission Units for BACT Analysis

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

- Combined-Cycle Stationary Combustion Turbines (EPNs: STK-101 and STK-102)
- Auxiliary Boiler (EPN: ABLSTK-100)
- Emergency Generator (EPN: EGENSTK-100)
- Fire Water Pump (EPN: FWPSTK-100)
- Natural Gas Fugitives (EPN: FUGNG-100)
- SF_6 Insulated Equipment (EPN: SF6-100)

IX. Combined-Cycle Combustion Turbines (EPNs: STK-101 and STK-102)

Two new natural gas fired combined-cycle stationary combustion turbines, Siemens SGT6-5000F, GE 7FA.04 or equivalently rated, (STK-101 and STK-102) will be used for power generation. The BACT analysis for the turbines considered two types of GHG emission reduction alternatives: (1) energy efficiency processes, practices, and designs for the turbines and other facility components; and (2) carbon capture and storage/sequestration (CCS). The proposed energy efficiency processes, practices, and designs discussed in Step 1 will be the same for any combustion turbine selected by LCH.

As part of the PSD review, LCH provided in the GHG permit application a five-step top-down BACT analysis for the combustion turbines. EPA has reviewed the LCH's BACT analysis for the combustion turbines, which is part of the record for this permit (including this statement of basis), and also provide analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identify All Available Control Options

(1) Energy Efficiency Processes, Practices, and Design

Combustion Turbine:

- *Combustion Turbine Design* – The most efficient way to generate electricity from a natural gas fuel source is the use of a combined-cycle combustion turbine. Furthermore, LCH will select a modern, highly efficient turbines, in terms of their heat rate (expressed as number of BTUs of heat energy required to produce a kilowatt-hour of electricity), which is a measure that reflects how efficiently a generator uses heat energy.
- *Periodic Maintenance and Tune-up* – After several months of continuous operation of the combustion turbine, fouling and degradation contribute to a loss of thermal efficiency. A periodic maintenance program consisting of inspection and cleaning of key equipment components and tuning of the combustion system will minimize performance degradation and recover thermal efficiency to the maximum extent possible. Regularly scheduled combustion inspections involving tuning of the combustors are used to maintain optimal thermal efficiency and performance.
- *Reduction in Heat Loss* – Insulation blankets will be applied to the combustion turbine casing if the Siemens turbines are selected. LCH represented that the GE turbines are designed with an enclosure that acts as an insulating media. These blankets and/or the turbine enclosure act as an insulating media and minimize the heat loss through the combustion turbine shell improving the overall efficiency of the machine.
- *Instrumentation and Controls*– Proper instrumentation ensures efficient turbine operation to minimize fuel consumption and resulting GHG emissions. Distributed digital system controls are used to automate processes for optimal operation.

Heat Recovery Steam Generator:

- *Heat Exchanger Design Considerations* – Efficient design of the HRSG improves overall thermal efficiency. This includes the following: finned tube, modular type heat recovery surfaces for efficient, economical heat recovery; use of an economizer, which is a heat exchanger that recovers heat from the exhaust gas to preheat incoming HRSG boiler feedwater to attain industry standard performance (ISO) for thermal efficiency; use of a heat exchanger to recover heat from HRSG blowdown to preheat feedwater; use of hot condensate as feedwater which results in less heat required to produce steam in the HRSG, thus improving thermal efficiency; and application of insulation to HRSG surfaces and steam and water lines to minimize heat loss from radiation.

- *Insulation* – Insulation minimizes heat loss.
- *Minimizing Fouling of Heat Exchange Surfaces* – Filtration of the inlet air to the combustion turbine is performed to minimize fouling. Fouling of interior and exterior surfaces of the heat exchanger tubes hinders the transfer of heat from the hot combustion gases to the boiler feedwater. This fouling occurs from contaminants in the turbine inlet air and in the feedwater. Fouling is minimized by inlet air filtration, maintaining proper feed water chemistry, and periodic maintenance, including cleaning the tube surfaces as needed during scheduled equipment outages. Additionally, cleaning of the tubes is performed during periodic outages. By reducing the fouling, the efficiency of the unit is maintained.
- *Minimizing Vented Steam and Repair of Steam Leaks* – Steam loss through venting and leakage reduces the efficiency of the heat exchanger. Restricting the venting outlets is used to maximize steam retention for power generation.

<u>Steam Turbine:</u>

- *Use of Reheat Cycles* – Reheat cycles are employed to minimize the moisture content of the exhaust steam. This cycle reheats partially expanded steam from the steam turbine.
- *Use of Exhaust Steam Condenser* – The exhaust steam is saturated under vacuum condition by the use of a condenser. The condensing steam creates a vacuum in the condenser, which increases steam turbine efficiency.
- *Efficient Blading Design and Turbine Seals* – Blade design has evolved for high-efficiency transfer of the energy in the steam to power generation. Blade materials are also important components in blade design, which allow for high-temperature and large exhaust areas to improve performance. The steam turbines have a multiple steam seal design to obtain the highest efficiency from the steam turbine.
- *Efficient Steam Turbine Generator Design* – The generator for modern steam turbines are cooled allowing for the highest efficiency of the generator, resulting in an overall high-efficiency steam turbine. The cooling method for the LCH steam turbine will be a cooling tower with a water-cooled condenser.

<u>Other Plant-wide Energy Efficiency Features</u>

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

- *Fuel Gas Preheating* – The overall efficiency of the combustion turbine is increased with increased fuel inlet temperatures.

- *Multiple Combustion Turbine/HRSG Trains* – Multiple trains allow the unit to achieve higher overall plant part-load efficiency by shutting down a train operating at less efficient part-load conditions and ramping up the remaining train to high-efficiency full-load operation.
- *Boiler Feed Pump Variable Speed Drives* – To minimize the power consumption at part-loads, the use of variable speed drives will be used to improve the facility's overall efficiency.

(2) Carbon Capture and Sequestration (CCS)

CCS is classified as an add-on pollution control technology, which involves the separation and capture of CO_2 from flue gas, pressurizing of the captured CO_2 into a pipeline for transport, and injection/storage within a geologic formation. CCS is generally applied to "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)."[1]

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 oxy-fuel 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, oxy-fuel 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 oxy-fuel combustion have no practical application for this proposed facility. The third approach, post-combustion capture, is applicable to the proposed combustion turbines. As such, post-combustion capture is the sole technology considered in this BACT analysis.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating power plant flue gas due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005). Of the potentially applicable technologies, post-combustion capture with an amine solvent such as

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[1] 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)

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 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 plan previously owned by Florida Power and Light (Bellingham Energy Center), currently owned by NESTera Energy Resources of which Florida Power and Light is a subsidiary. The CO_2 capture plan was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003) The CO_2 capture operation was discontinued in 2005 due to a change in operations from a baseload unit to a peak load shaving unit, which created technical impediments to continuing to operate the system.

Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[2]

Step 2 – Elimination of Technically Infeasible Alternatives

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

> *CCS could become a viable emission management option as new CO_2 capture technologies are developed. According to the US Department of Energy National Energy and Technology Laboratory (DOE-NETL), a 2009 review of commercially available CO_2 capture*

[2] 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

technologies presented that facilities capturing the highest volumes of CO_2 were all associated with gas streams containing relatively high concentrations of CO_2 (25-70%) such as natural gas processing operations and synthesis gas production. Capturing CO_2 from more dilute streams, such as those generated from power production, is less common as the following challenges are faced:

- *CO_2 is present at low pressure (15-25 psia) and dilute concentrations (3-4% volume) from the gas-fired turbine exhaust stream. Therefore, a very high volume of gas must be available to achieve the CO_2 mass flow necessary to recover CO_2 at a cost efficiency comparable to an application such as natural gas processing.*
- *Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the exhaust gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.*
- *Compressing the captured CO_2 from atmospheric pressure to pipeline pressure (about 2000 psia) presents a large auxiliary power load on the overall power plant system.*

Current industrial processes generally involve gas streams that are much lower volumes than that required for the purposes of GHG emissions mitigation at a typical power plant. Scaling up these existing processes represents a significant technical challenge and a potential barrier to widespread commercial deployment in the near term. No references to natural gas fired power plants using CCS were identified.

The combustion of natural gas at the proposed LCH Power station will produce an exhaust gas with a maximum CO_2 concentration of 4.5% by volume. This low concentration stream will require that a very high volume of gas be treated so that the CO_2 may be captured effectively. However, the CO_2 capture capacities used in current industrial processes are designed for relatively high CO_2 concentration streams (25% or higher), as discussed in the "Report of the Interagency Task Force on Carbon Capture and Storage" (August 2010)[3]

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

[3] http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf

logistical barriers do not make CCS technically infeasible for this project and have addressed the economic feasibility issues in Step 4 of the BACT analysis in order to assess whether CCS is BACT for this project. In addition, the other control options identified in Step 1 are considered technically feasible for this project.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Energy efficiency processes, practices, and designs are all considered effective and have a range of efficiency improvements that cannot be directly quantified, and therefore ranking them is not possible. CCS can potentially achieve large reductions (up to 90 percent) of CO_2 emissions from fossil fuel combustion.

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

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

<u>Carbon Capture and Storage (CCS)</u>

LCH developed a cost analysis for CCS. LCH estimated total estimated capital cost for CCS would be approximately $396 to 467 million. LCH has estimated that CCS for 90% capture would increase the capital cost of the project by 50% when compared to the cost without CCS. Based on these costs, LCH maintains that CCS is not economically feasible for their proposed project. LCH submitted information to support the underlying bases for this cost estimation.

Capital costs associated with CCS fall into two primary areas – CO_2 capture and compression equipment and CO_2 transport. The capture and compression equipment associated with CCS would have cost impacts based on the installation of the additional process equipment (e.g., amine units, cryogenic units, dehydration units, and compression facilities), while transport costs are associated with construction of a pipeline to transport the captured CO_2. LCH conducted an analysis of the capital cost impact of CCS capture and compression equipment by using project specific data along with the information provided in the "Report of the Interagency Task Force on Carbon Capture" (August 2010). The estimated capital cost for post combustion CO_2 capture and compression equipment was estimated to be $386 to 457 million. For transportation costs, LCH identified several facilities with a demonstrated capacity for geological storage of CO_2 in the Scurry Area Canyon Reef Operators (SACROC) oilfield that is over 300 miles from the project site. Several other candidate storage reservoirs exist within 10 to 50 miles from the project site, but none of these storage reservoirs have been demonstrated to be commercially available for large scale CO_2 storage. However, as a conservative estimate of the capital cost to transport the captured CO_2, LCH chose to rely on a 10 mile distance to the nearest potential storage site. Based on a 10-inch diameter pipe, LCH has estimated that the total capital cost of the CO_2 pipeline is approximately $10 million. Accordingly, the total estimated capital cost for CCS at this facility is approximately $396 to 467 million. Furthermore, the recovery and purification of CO_2 from the stack gases would necessitate significant additional processing, including energy, and environmental/air quality penalties, to achieve the necessary CO_2 concentration for effective sequestration. The additional process equipment required to separate, cool, and compress the CO_2, would require a significant additional water and power expenditure. This equipment would include amine scrubber vessels, CO_2 strippers, amine transfer pumps, flue gas fans, an amine storage tank, and CO_2 gas compressors. The water use for a combined cycle plant with CCS would be 7.6 - 9.5 million gallons per day. The additional GHG emissions resulting from additional fuel combustion would either further increase the cost of the CCS system, if the emissions were also captured for sequestration, or reduce the net amount GHG emission reduction, making CCS even less cost effective than expected.

Based on the control cost, the comparison of total capital cost of control to the project cost, and the decrease in net power output due to the additional power requirements for CCS, LCH maintains that CCS is not economically feasible. EPA has reviewed these estimated CCS cost projections. Based upon the potential volume of CO_2 emissions from the project that would be available for capture and the current estimates of CCS costs, EPA believes the applicant's estimated costs to install CCS at the facility are credible. EPA concludes that such costs would render the project economically unfeasible for LCH, therefore EPA is eliminating CCS as BACT for this proposed project.

<u>Energy Efficiency Processes, Practices, and Design</u>

There are no known adverse economic, energy, or environmental impacts associated with the control technologies and techniques identified in Step 1 for energy efficiency process, practices, and design. All of these options are proposed for the facility.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the turbines:

- Use of combined cycle power generation technology
- Combustion-turbine energy efficiency processes, practices, and design
    - Highly efficient turbine design
    - Turbine inlet air cooling
    - Periodic turbine burner tuning
    - Reduction in heat loss

    - Instrumentation and controls
- HRSG energy efficiency processes, practices, and design
    - Efficient heat exchanger design
    - Insulation of HRSG
    - Minimizing fouling of heat exchange surfaces
    - Minimizing vented steam and repair of steam leaks
- Steam turbine energy efficiency processes, practices, and design
    - Use of reheat cycles
    - Use of exhaust steam condenser
    - Efficient blade design
    - Efficient generator design
- Plant-wide energy efficiency processes, practices, and design
    - Fuel gas preheating
    - Drain operation
    - Multiple combustion turbine/HRSG trains
    - Boiler feed pump fluid drive design

BACT Limits and Compliance:

To determine the appropriate heat-input efficiency limit, Lon C. Hill, LP started with the turbine's design base load net heat rate for combined cycle operation and then calculated a compliance margin based upon reasonable degradation factors that may foreseeably reduce efficiency under real-world conditions. The design base load gross heat rates for the combustion turbines being considered for this project are as follows:

Combustion Turbine Model	Gross Heat Rate[1] (HHV) (Btu/KWhr)	Duct Burners Annual Firing Rate[1] (HHV) (MMBtu/hr)	Output-Based Emission Limit, Gross Basis, with or without duct burning[1] (lb CO_2/MWh)	MSS Emission BACT Limit[2] (tons CO_2/hr)
Siemens SGT6-5000F GE 7FA.04 or equivalently rated	7,720	670	920	115

[1]Limits are based on a 12-month rolling average.
[2]Limit is calculated based on a 12-month rolling average of tons CO_2/hr divided by the number of hours of maintenance, startup and shut down for that 12-month period.

These rates reflect the facility's "gross" power production, meaning the total amount of energy produced by the plant, which also includes auxiliary load consumed by operation of the plant. To be consistent with other recent GHG BACT determinations, the annual average firing rate with and without duct burner firing is used to calculate the heat-input efficiency limit.

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

- 3.3% design margin reflecting the possibility that the constructed facility will not be able to achieve the design heat rate;
- 6.0% performance margin reflecting efficiency losses due to equipment degradation prior to maintenance overhauls; and,
- 3.0% degradation margin reflecting the variations in operation of ancillary plant facilities.

Design Margin - Design and construction of a combined cycle power plant involves many assumptions about anticipated performance of the many elements of the plant, which are often imprecise or not reflective of conditions once installed at the site. Based on other GHG permits and permit application reviews by EPA Region 6, most combined cycle power plants have a design margin up to 5% for the guaranteed net MW output and net heat rate. This is the condition for which the contractor has a "make right" obligation to continue tuning the facility's performance to achieve this minimum value. Therefore, the contractor must deliver a facility that is capable of generating 95% of the guaranteed MW and must have a heat rate that is no more than 105% of the guaranteed heat rate. With LCH's expertise and experience with combined cycle power plant construction, a design margin of 3.3% is requested.

Performance Margin on Combustion Turbine and Steam Turbine Generators - The performance margin for equipment degradation relates to the combustion turbine and steam turbine generators. Manufacturer's degradation curves project anticipated degradation rates of 6% within the first 48,000 hours of the gas turbine's useful life; they do not reflect any potential increase in this rate which might be expected after the first major overhaul and/or as the equipment approaches the end of its useful life. Further, the project 6% degradation rate represents the average, and not the maximum or guaranteed, rate of degradation for the gas turbine. Therefore, LCH proposes, based on previous GHG permitting actions, a 20-year degradation of 6%. This degradation rate is comparable to the rates estimated by other natural gas fired power plants that have received a GHG PSD permit.

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

The following BACT limits are proposed:

Turbine Model	Gross Heat Rate, with duct burner[1] firing (HHV) (Btu/kWh)	Duct Burners Annual Firing Rate[1] (MMBtu/hr)	Output Based Emission Limit, Gross Basis, with or without duct burning[1] (lb CO_2/MWh)	MSS Emission BACT Limit[2] (tons CO_2/hr)
Siemens SGT 5000F, GE 7FA.04 or equivalently rated	7,720	670	920	115

[1]Limits are based on a 12-month rolling average.
[2]Limit is calculated based on a 12-month rolling average of tons CO_2/hr divided by the number of hours of maintenance, startup and shut down for that 12-month period.

The calculation of the gross heat rate was provided in supplemental information provided by LCH on March 25, and August 14, 2014 and the site wide mass emission rate in tons per year is provided in Attachment B of the application, converted to lbs CO_2/MWh. A BACT limit to be applied during startup, and shutdown conditions, or during periods of maintenance is also provided. The MSS BACT limit was developed and presented by LCH in supplemental information on August 14, 2014. While energy efficiency will be a consideration for final selection of a turbine, other considerations will include the capacity of the turbine, cost, reliability, and predicted longevity of the turbines.

Since the plant heat rate varies according to turbine operating load and amount of duct burner firing, LCH proposes to demonstrate compliance with the proposed heat rate with an annual compliance test, at 100% load, corrected to ISO conditions.

LCH's proposed BACT limit is expressed in pounds CO_2/MWh. The output based emissions limit was selected from a range of limits based on operating conditions, and age of turbine provided by LCH. When compared to other BACT limits established for other combined cycle/heat recovery steam generating units, the proposed emission limits for the LCHPS are comparable to the limits established in other recently issued permits for LCRA, Calpine Deer Park, Calpine Channel Energy Center, Florida Power and Light Port Everglades, La Paloma Energy Center, FGE Power Texas and Pinecrest Energy Center. The net heat rate proposed for LCHPS is comparable to LCRA, Calpine Deer Park, Calpine Channel Energy Center, Florida Power and Light Port Everglades, La Paloma Energy Center, FGE Power Texas and Pinecrest Energy Center. LCH is expected to operate at base load conditions.

To date, other similar facilities with a GHG BACT limit are summarized in the table below: All facilities listed below will use energy efficiency, good design and combustion practices as control devices.

GHG (CO_2) Permit Limit for Combined Cycle Power Plants

Facility Name & Location	Permit Year	Plant Size (MW)	Plant Type	Types of Units	Heat Rate Limit (Btu/Kwhr)	Output based GHG Emissions Limit
Lower Colorado River Authority (LCRA) Thomas C. Ferguson Plant Horseshoe Bay, TX	2011	590	Two natural gas fire turbines and heat recovery steam generators (HRSG) and one steam turbine generator	2-GE 7FA combustion turbines	7,720 (HHV)	0.459 ton CO_2/MWh (net) = 918 lbs CO_2/MWh approx. No duct firing 365 day rolling average
Palmdale Hybrid Power Plant Project* Palmdale, CA	2011	570	Two natural gas fire turbines and HRSGs, one steam turbine and 50 MW Solar-Thermal Plant	2GE 7FA combustion turbines	7,319 source wide	774 lb CO_2/MWh source-wide (net) output on 365 day rolling average
Calpine Deer Park Energy Center Deer Park, TX	2012	168/180	Added one turbine to 4 existing turbines, CC and HRSG	Siemens 501F	7,730	0.46 tons CO_2/MWh (net) = 920 lbs CO_2/MW on 30 day rolling average without duct burning
Calpine Channel Energy Center Pasadena, TX	2012	168/180	Added a third CTG HRSG to existing turbine.	Siemens 501F	7,730	0.46 tons CO_2/MWh (net) = 920 lbs CO_2/MW on 30 day rolling average without duct burning
Florida Power and Light Port Everglades Hollywood, FL	2013	1250	Three natural gas fired turbines and HRSGs and one steam turbine	Mitsubishi 501J CT or Siemens HCGs	6,488	830 lb CO_2e/MWh (net) on a 12-month rolling average when operating at 100% load using natural gas.

La Paloma Energy Center Harlingen, TX	2014	637-735	Two natural gas fired turbines and HRSGs and one steam turbine generator	GE 7FA Or Siemens SGT6-5000F(4) or Siemens SGT6-5000 (5)	7,861 for the GE or 7,649 or 7,679 for the Siemens.	934.5 lb CO_2/MWh 909.2 CO_2/MWh 912.7 lb CO_2/MWh Respectively, gross with duct burning 12 operating month average
FGE Power Texas Westbrook, TX	2014	1,620	2 combined cycle power blocks, each in a 2 on 1 configuration consisting of two combustion turbines two supplementally fired HRSGs & one steam turbine	Alstrom	7,625	889 lb CO_2/MWh gross
Pinecrest Energy Center Lufkin, TX	2014	637-735	2 natural gas tired turbines and HRSGs and one steam turbine generator	GE 7FA.05 Siemens SGT6 5000F(4) Siemens SGT6 5000F5	7,925 7,649 7,649	909-942 lb CO_2/MWh depending on turbine model selected

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

On January 8, 2014, EPA proposed New Source Performance Standard (NSPS) 40 CFR Part 60 Subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Generating Units, 77 FR 22392) that would control CO_2 emissions from new electric generating units (EGUs). The proposed rule would apply to fossil fuel fired EGUs that are larger than 73 MW heat input of fossil fuel and supplies at least one-third of their potential electric power output to a utility grid. EPA proposed that large, natural gas combined cycle EGUs must meet an annual average output-based standard of 1,000 lb CO_2/MWh, on a gross output basis. The proposed emission rate for the LCH combustion turbine, on a gross electrical output basis, is 920 lb CO_2/MWh, with or without duct burner firing. The proposed CO_2 emission rate for the LCH combustion turbine is therefore less than the emission limit proposed in the NSPS at 40 CFR Part 60 Subpart TTTT.

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

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

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

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

The equation for estimating CO_2 emissions as specified in 40 CFR § 75.10(3)(ii) is as follows:

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

Where:

W_{CO2} = CO_2 emitted from combustion, tons/hour
MW_{CO2} = molecular weight of CO_2, 44.0 lbs/mole
Fc = Carbon-based Fc-Factor, 1040 scf/MMBtu for natural gas or site-specific Fc factor
H = hourly heat input in MMBtu, as calculated using the procedure in 40 CFR Part 75, Appendix F §5
Uf = 1/385 scf CO_2/lb-mole at 14.7 psia and 68°F

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

- Fuel flow meter

- Gross Calorific Value (GCV)

This approach is consistent with the CO_2 reporting requirements of 40 CFR Part 98, Subpart D-GHG Mandatory Reporting Rule for Electricity Generation. Furthermore, CO_2 will be monitored at the LCHPS in a manner that is consistent with the recently proposed New Source Performance Standards, Subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for Electric Utility Generating Units), which allows for electric generating units firing gaseous fuel to determine CO_2 mass emissions by monitoring fuel combusted in the affected electric generating unit and using a site specific Fc factor determined in accordance to 40 CFR Part 75, Appendix F. If LCH chooses to install and operate the CO_2 CEMS equipped with a volumetric stack gas monitoring system, the applicant shall rely on the data from the CO_2 CEMS for compliance purposes.

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

An initial stack test demonstration will be required for CO_2 emissions from STK-101 and STK-102. LCH also proposes to demonstrate compliance with the proposed heat rate with an annual compliance test, at 100% load, corrected to ISO conditions. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emission are approximately 0.01% of the total CO_2e emissions from the combustion turbines.

X. Auxiliary Boiler (EPN: ABLSTK-100)

One nominally rated 95 MMBtu/hr auxiliary boiler (EPN ABLSTK-100) may be utilized to facilitate startup of the combined cycle units and to provide pre-warming steam to the steam turbine generators prior to startup. The auxiliary boiler will be limited to 500 hours of operation per year.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Use of Low Carbon Fuels* – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions. Natural gas is the lowest carbon fuel available at LCH.

- *Use of Good Operating and Maintenance Practices* – Following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing in the combustion zone; and maintain the proper air/fuel ratio so that sufficient oxygen is provided to provide complete combustion of fuel while at the same time preventing introduction of more air than is necessary into the boiler.
- *Energy Efficient Design* – The auxiliary boiler is designed for a thermal efficiency of approximately 80%. The energy efficient design includes insulation to retain heat within the boiler and a computerized process control system that will optimize the fuel/air mixture and limit excess air in the boiler.
- *Low Annual Capacity* – The auxiliary boiler will be used to facilitate the startup of the two combustion turbines and steam turbines the annual hours of operation will be limited to 500 hours per year.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

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

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

Step 5 – Selection of BACT

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

- Use of low carbon fuel (natural gas). Natural gas will be the only fuel fired in the proposed auxiliary boiler. It is the lowest carbon fuel available for use at LCH.

- Good operation and maintenance practices will include following the manufacturer's recommended operating and maintenance procedures; maintaining good fuel mixing, and limiting the amount of excess air in the combustion chamber to maximize thermal efficiency.
- Energy efficient design will incorporate insulation to retain heat within the boiler.
- The auxiliary boiler will be limited to 500 hours of operation a year.
- The maximum firing rate for the auxiliary boiler shall not exceed 95 MMBtu/hr.

Use of these practices corresponds with a permit limit of 2,779 TPY CO_2e for the auxiliary boiler. Compliance will be determined by the number of hours of operation and the calculated emissions using Equation C-1 from 40 CFR Part 98 Subpart C, which is based on metered fuel usage and the emission factor for natural gas.

XI. Emergency Engines (EPN:EGENSTK-100 and FWPSTK-100)

The LCH site will be equipped with one nominally rated 1,341-hp diesel-fired emergency generator to provide electricity to the facility in the case of power failure and one nominally rated 617-hp diesel-fired pump to provide water in the event of a fire.

Step 1 – Identification of Potential Control Technologies

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

Step 2 – Elimination of Technically Infeasible Alternatives

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

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

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

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

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

Step 5 – Selection of BACT

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

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

Using the BACT practices identified above results in a BACT limit of 77 TPY CO_2e for the Emergency Generator (EGENSTK-100) and 35 TPY CO_2e for the Fire Water Pump (FWPSTK-100). LCH 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, as updated by 78 FR 71904 Nov. 29, 2013, site specific analysis of process fuel gas, and the actual heat input (HHV). The emergency engines installed and operated at LCH shall meet the performance requirements outlined in 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

XII. Natural Gas Fugitive Emissions (EPN:FUGNG-100)

The proposed project will include natural gas piping components. These components are potential sources of methane emissions due to emissions from rotary shaft seals, connection interfaces, valve stems, and similar points. The additional methane emissions from process fugitives have been conservatively estimated to be 1,100 TPY as CO_2e.

Fugitive emissions are negligible, and account for less than 0.04% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

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

Step 2 – Elimination of Technically Infeasible Alternatives

LDAR programs, monitoring with remote sensing technology, and AVO monitoring are all technically feasible option for controlling process fugitive GHG emissions.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Instrument LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[4] The most stringent LDAR

[4] 73 FR 78199-78219, December 22, 2008.

program potentially applicable to this facility is TCEQ's 28LAER, which provides for 97% control credit for valves, flanges, and connectors.

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

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

Although instrument LDAR and/or remote sensing of piping fugitive emissions in natural gas service may be somewhat more effective than as-observed AVO methods, the incremental GHG emissions controlled by implementation of the TCEQ 28LAER LDAR program or a comparable remote sensing program is less than 0.05% of the total project's proposed CO_2e emissions. Accordingly, given the costs of implementing 28LAER or a comparable remote sensing program when not otherwise required, these methods are not economically practicable for GHG control from components in natural gas service.

Step 5 – Selection of BACT

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

XIII. SF_6 Insulated Electrical Equipment (SF6-100)

The generator circuit breakers associated with the proposed units will be insulated with SF_6. The capacity of the circuit breakers associated with the proposed plant is currently estimated to be about 75 pounds of SF_6.

Step 1 – Identification of Potential Control Technologies for GHGs

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

Alternative Dielectric Material- Because SF_6 has a high GWP, one alternative considered in this analysis is to substitute another non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NIST) Technical note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure* SF_6.[5] The alternatives considered include mixtures of SF_6 and nitrogen, gases and mixtures and potential gases for which little experimental data are available.

Step 2 – Elimination of Technically Infeasible Alternatives

Circuit Breaker Design Efficiency - Considered technical feasible and is carried forward for Step 3 analysis.

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

[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

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

Step 5 – Selection of BACT

Circuit breaker design efficiency is selected as BACT. Specifically, state-of-the-art enclosed-pressure SF_6 circuit breakers with leak detection is the BACT control technology option. The circuit breakers will be designed to meet the latest of the American National Standards Institute (ANSI) C37.06 and C27.010 standards for high voltage circuit breakers.[6] 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 lack of “quenching and cooling” SF_6 gas. There will be three breakers at the facility. LCH calculated a maximum annual leak rate of 0.0002 TPY of SF_6 (CO_{2e} is 15 TPY) Therefore, LCH proposes that a leak detection system is not necessary to satisfy BACT requirements, however all SF_6 circuit breakers are fitted with alarms.

XIV. Gaseous Venting (TRB-MSS)

LCH will have small amounts of GHGs emitted from gaseous fuel venting during turbine shutdown and maintenance from the fuel lines being cleared of fuel. They will also have small amounts of GHGs emitted from the repair and replacement of small equipment and fugitive components. The GHG emissions from these activities account for less than 0.0001% of the total project GHG emissions. Due to the infrequent nature of these activities and small quantity of GHG emissions, a BACT analysis is not warranted.

XV. 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) submitted to EPA on June 18, 2014, prepared by the applicant, Lon C. Hill, LP (LCH), and its consultant, Whitenton Group, LLC (Whitenton), thoroughly reviewed and adopted by EPA.

The draft BA identifies 24 species as federally endangered or threatened in Nueces and San Patricio Counties, Texas:

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

Federally Listed Species for San Patricio and Nueces County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Plant	
South Texas ambrosia	*Ambrosia cheiranthifolia*
Slender rush-pea	*Hoffmannseggia tenella*
Birds	
Piper Plover	*Charadrius melodus*
North Aplomado falcon	*Falco femoralis septentrionalis*
Yellow-billed cuckoo	*Coccyzus americanus*
Eskimo curlew	*Numenius borealis*
Whooping Crane	*Grus americana*
Red knot	*Calidris canutus rufa*
Fish	
Smalltooth sawfish	*Pristis pectinata*
Mammals	
Ocelot	*Leopardus pardalis*
Gulf coast jaguarundi	*Herpailurus yagouaroundi cacomitli*
Red Wolf	*Canis rufus*
Reptiles	
Green sea turtle	*Chelonia mydas*
Hawksbill sea turtle	*Eretmochelys imbricata*
Kemp's ridley sea turtle	*Lepidochelys kempii*
Leatherback sea turtle	*Dermochelys coriacea*
Loggerhead sea turtle.	*Caretta caretta*
Marine Mammals	
West Indian manatee	*Trichechus manatus*
Blue whale	*Balaenoptera musculus*
Finback whale	*Balaenoptera physalus*
Humpback whale	*Megaptera novaeangliae*
Sei whale	*Balaenoptera borealis*
Sperm whale	*Physeter macrocephalus*

With the exception of the whooping crane, EPA has determined that issuance of the proposed permit to LCH will have no effect on 22 of the 23 federally-listed species. These species are either thought to be extirpated from these counties or Texas or not present in the action area as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

However, the whooping crane (*Grus americana*) is a species that may be present in the action area during migration as the proposed project area is located within the whooping crane migration corridor and is approximately 33 miles southwest from whooping crane habitat, Aransas National Wild Refuge. Information in the BA indicates that there is no known or potential habitat for the cranes within the action area. However, because the use of certain construction equipment poses a possible but unlikely risk of bird strikes during flyovers, LCH has agreed to implement measures to minimize any potential adverse effects the project may have on the whooping crane, as indicated in its BA

EPA will submit the final draft BA to the Southwest Region, Corpus Christi, Texas Ecological Services Field Office of the U.S. Fish and Wildlife Service(USFWS), and request concurrence from USFWS that issuance of the permit may affect, but is not likely to adversely affect the whooping crane.

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 BA can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVI. National Historic Preservation Act (NHPA)

Section 106 of the National Historic Preservation Act (NHPA) requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report dated August 13, 2014, prepared by Horizon Environmental Services (Horizon) on behalf of Whitenton, a contractor to LCH and the EPA.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be 45.4-acres of land that contains the construction footprint of the project. The project site was formerly the site of a power plant that ceased operations in 2002 and was subsequently demolished. Horizon performed a field survey of the property and a desktop review on the archeological background and historical records within a one-mile radius of the APE. The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP).

Based on the results of the field survey, no archeological resources or historic structures were found within the APE. Based on the desktop review for the site, one previous cultural resources background study was done in 2008. Eight previously recorded archeological sites were identified within a one-mile radius of the APE, but none are within the APE. No cemeteries or historic properties listed on the NRHP are present within a mile of the APE.

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

On July 2, 2014, 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 EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit.

EPA submitted a copy of the final draft of the cultural report to the State Historic Preservation Officer for consultation and requested concurrence with its determination on August 14, 2014. 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.

XVII. 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.

XVIII. Conclusion and Proposed Action

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

APPENDIX

Annual Facility Emission Limits

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

Table 1. Annual Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements[1]
				TPY[2]		
CC-101	STK-101	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,255,491	1,256,763	920 lb CO_2/MWh (gross) with duct burning.[5] Start-up and Shutdown emissions limited to 500 hours per year. MSS emissions are limited to 115 tons CO_2/hr. See Special Conditions IV.A.1 and Table 2.
			CH_4	23.30		
			N_2O	2.33		
CC102	STK-102	Combined Cycle Combustion Turbine/Heat Recovery Steam Generator[4]	CO_2	1,255,491	1,256,763	920 lb CO_2/MWh (gross) with duct burning.[5] See Special Conditions IV.A.1 and Table 2
			CH_4	23.30		
			N_2O	2.33		
ABL-100	ABLSTK-100	Auxiliary Boiler	CO_2	2,779	2,779	Good Combustion and Operating Practices. Limit to 500 hours of operation per year. See Special Conditions IV.B.
			CH_4	0.052		
			N_2O	0.005		
EGEN-100	EGENSTK-100	Emergency Generator	CO_2	80	80	Good Combustion and Operating Practices. Limit to 100 hours of operation per
			CH_4	No Numerical		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements[1]
				TPY[2]		
				Limit Established[6]		year. See Special Conditions IV.C.
			N_2O	No Numerical Limit Established[6]		
FWP-100	FWPSTK-100	Fire Water Pump	CO_2	35.2	35.2	Good Combustion and Operating Practices. Limit to 100 hours of operation per year. See Special Conditions IV.C.
			CH_4	No Numerical Limit Established[6]		
			N_2O	No Numerical Limit Established[6]		
NG-FUG	NG-FUG	Natural Gas Fugitives	CO_2	Not Applicable	Not Applicable	Implementation of AVO Monitoring.
			CH_4	Not Applicable		
SF6-100	SF6-100	SF_6 Insulated Equipment	SF_6	No Numerical Limit Established[6]	4.1	Instrumented monitoring and alarm. See Special condition IV.D.
Totals[7]			**CO_2**	**2,518,530**	**2,517,468 CO_2e**	
			CH_4	**89**		
			N_2O	**4.67**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling total.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298, CO_2=1, SF_6=22,800
4. The annual emissions limit for the combustion turbines is based on operating at maximum duct burner firing for 4,375 hours per year.
5. The BACT limit for the combustion turbine does not apply during MSS.
6. All values indicated as “No Numerical Limit Established” are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. Total emissions are for information only and do not constitute an emission limit.