4. Please expand the discussion on the plant startup system and operations. Please explain your ramp up power generation in relation to the 2628 hours per year (more than 7 hours per day) auxiliary boiler operation you've requested for startup/shutdown. Typical startups are about 30 minutes per day. Please provide the technical basis for when your startup and shutdown ends for the specific turbine model that may be selected and pollution control equipment you are planning to utilize. Please provide additional information about the number of startups and shutdown per year.

The design of the new facility includes a natural gas fired auxiliary boiler to provide pre-warming steam to the steam turbine generator prior to startup. Use of the auxiliary boiler will decrease the amount of time that the combustion turbines must be run at low output levels during startup, particularly during cold startups; thereby reducing overall emissions from the plant.

The auxiliary boiler will be designed to nominally produce 31,000 pounds of steam per hour at a maximum heat input of 48.4 MMBtu/hr. The maximum annual capacity factor will be 30%, which equates to 2,628 hours per year. This amount of operating hours is conservatively high and includes auxiliary boiler startup time and operating time required to warm the steam turbine and hold the unit in warm standby. Typical startups for these units exceed 30 minutes per startup. The amount of time required to warm the steam turbine following an extended shut down (approximately 241 minutes for cold startup) will be significantly greater than a hot or warm start (approximately 93 to 136 minutes).

The LCH plant may have to operate as a merchant facility. If this is the case, the facility will require maximum operational flexibility to respond to the demands of the energy market, including the possibility of frequent startups. For the purpose of conservatively estimating the mass emissions that may result from the facility under a number of economic conditions, we assumed 572 total hours of startup/shut down events per unit per year. The duration of the startups will be minimized to the best extent possible for each unit.

A startup is initiated when the Data Acquisition and Handling System (DAHS) detects a flame signal and ends when the permissive for the emission control system are met (i.e., steady state emissions compliance is achieved). The turbines will have the following typical startups:

- Cold Startup: is a startup after an extended GT shutdown of greater than 64 hours, with the ST HP/IP metal temperatures less than 485 °F (252 °C). It is expected to have no more than 10 events per year at approximately 241 minutes per event;
- Warm Startup: is a startup after a GT shutdown of 16 to 64 hours, with the ST HP/IP metal temperatures between 485 °F (252 °C) and 685 °F (363 °C). It is expected to have no more than 50 events per year at approximately 136 minutes per event;
- Hot Startup: is a startup after a GT shutdown of less than 16 hours, with the ST HP/IP metal temperatures greater than ~ 685 °F (363 °C). It is expected to have no more than 200 events per year at approximately 93 minutes per event; and

A **shutdown** begins when the load drops to the point at which steady state emissions compliance can no longer be assured and ends when a flame-off signal is detected.

We have represented a conservative operating scenario that combines hot, warm, and cold startups to achieve the worst case (i.e., maximum emission rate expected from the new facility). This facility will likely be a merchant facility and cannot be operationally constrained to a specific number of hot, warm, or cold startups. Therefore, LCH has requested that compliance be demonstrated by maintaining short and long term emission rates below those represented in the permit application, rather than a specific number of hot, warm, and/or cold startups.

Operation of the auxiliary boiler at a maximum capacity factor of 0.3 (30%), will help ensure that this operational flexibility is available.

5. To date, EPA Region 6 has not eliminated carbon capture sequestration from its BACT determinations based on technical infeasibility for combined cycle power plants. Since this is a proposed natural gas combined cycle power plant, please provide additional details, for BACT purposes, on the economics of installing a CCS system at the plant.

- **(a) Specifically, please provide the site-specific information on the estimated concentration of CO_2 that is in the waste stream.**
- **(b) Also, please provide site-specific cost calculations including, but are not limited to, size and distance of pipeline to be installed for potential enhanced oil recovery (EOR) opportunities, estimated costs for a capture system (pumps, compressors, amine solution) that specifically identifies the equipment necessary to employ a post-combustion CCS system.**
- **(c) Please include the estimated cost of construction, operation and maintenance, on an annual basis. Feel free to provide an estimated cost per ton of CO_2 removed for the CCS system and/or the percentage of increased costs of a CCS system above your estimated non-CCS capital costs for the project. Please discuss in detail any site specific safety or environmental impacts associated with installation and operation of the CCS system.**

(a) Estimated concentration of CO2 in waste stream. CO_2 is present at low pressure (15-25 psia) and dilute concentrations (3-4 percent volume) from the gas-fired turbine exhaust streams. The estimated maximum concentration from the LCH exhaust stream is estimated to be 4.5 percent by volume. 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.

(b) CCS Cost Calculations. Please see attached cost estimate to implement CCS. The costs are summarized below and include the capture system, cost of the pipeline for transport, and post-combustion CCS system costs (storage).

Total CCS System Annualized Cost

CCS System Component	Technology Cost ($/metric ton)	CO_2 Controlled (metric tons/yr)	Total Annualized Cost
CO_2 Capture and Compression Facilities	$114	2,260,140.93	$257,656,067
CO_2 Transport Facilities [(2)]	$0.66		$1,493,605
CO_2 Storage Facilities [(3)]	$0.56		$1,265,679
Total CCS System Annualized Cost	**$115**		**$260,415,350**

(c) Site specific impacts. Several site specific factors need to be considered. This includes:

CO_2 Capture

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_2capture 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 to 70 percent) 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 percent 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 2,000 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 Lon C. Hill Power Station will produce an exhaust gas with a maximum CO_2 concentration of 4.5 volume percent. 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 percent or higher), as discussed in the “Report of the Interagency Task Force on Carbon Capture and Storage” (August 2010).

CO_2 Transport

Even if it is assumed that CO_2 capture could feasibly be achieved for the proposed project, the high-volume CO_2 stream generated (maximum 45,807 scf/min of CO_2) would need to be transported to a facility capable of storing it. Figure 1 is a map showing the location of current CO_2 pipelines in the United States.

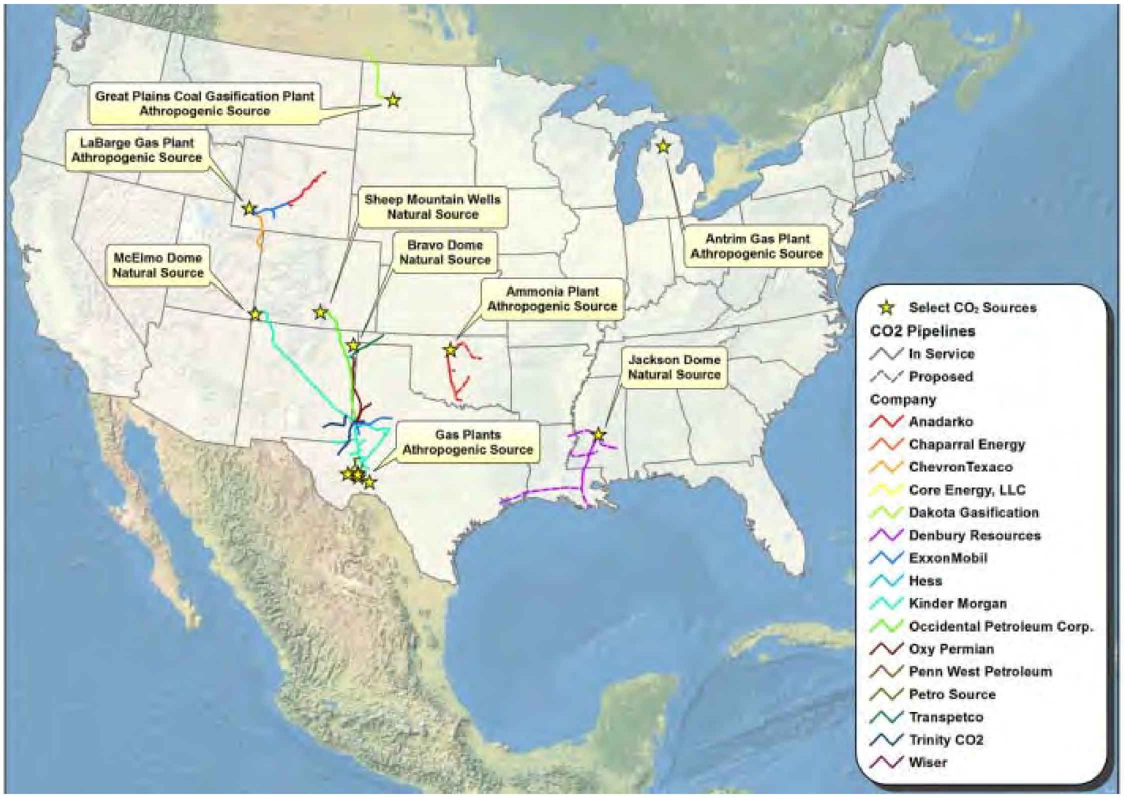

Figure 1 – Existing and Planned CO_2 Pipelines in the United States
[Source: Report of the Interagency Task Force on Carbon Capture and Storage, Fig. B-1, August 2010]

As shown on this map, there are no existing pipelines that could transport the CO_2 stream from the proposed plant to any potential storage facility. The closest site to the proposed project, with some demonstrated capacity for geological storage of CO_2, is the Scurry Area Canyon Reef Operators (SACROC) oilfield near the eastern edge of the Permian Basin in Scurry County, Texas[1]. This site is over 390 miles away from Lon C. Hill Power Station; therefore, a very long and sizable pipeline would be required to transport the large volume of high pressure CO_2 from the plant to the storage facility which will make CCS economically infeasible. Several other candidate storage reservoirs exist within 10 to 50 miles from the proposed project along the east Texas' basins (see Figure 2); however, none have been confirmed to be viable for large scale CO_2 storage at this time.

CO_2 Storage

Even if it is assumed that CO_2 capture could feasibly be achieved for the proposed project and that the CO_2 could be transported economically, the feasibility of CCS would still depend on the availability of a long-term safe storage site.

Ongoing regional-scale assessments suggest a large resource potential for storage in the United States. According to the National Carbon Sequestration Database and Geographic Information System

[1]http://www.beg.utexas.edu/gccc/sacroc.php

(NATCARB)[2] Texas CO_2 potential storage resources are within 441,283 metric tons (low estimate) and 4,297,550 metric tons (high estimate) including saline formations, unminable coal seams and oil/gas reservoirs. Figure 2 shows the Basins outlines in the United States, as provided by NATCARB 2012 United States and Canadian Carbon Storage Atlas.

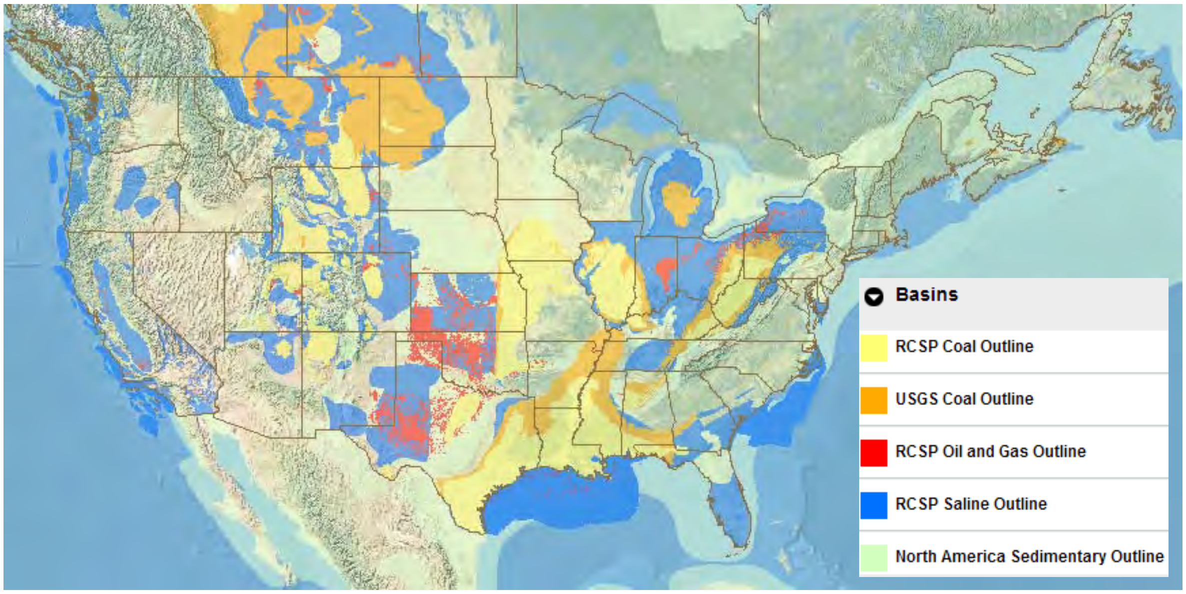

Figure 2 –Basins Outlines in United States
[Source: NATCARB 2012 United States and Canadian Carbon Storage Atlas]

According to the conclusions of the "Report of the Interagency Task Force on Carbon Capture and Storage" (August 2010)[3], to enable widespread, safe, and effective CCS, CO_2 storage should continue to be field-demonstrated for a variety of geologic reservoir classes, with large-scale projects targeted at high-priority reservoir classes and smaller-scale projects covering a wider range of classes that are important regionally.

Small and large-scale field tests in different geological storage classes are being conducted to confirm that CO_2 capture, transportation, and storage can be achieved safely, permanently, and economically. Results from these tests will provide a more thorough understanding of migration and permanent storage of CO_2 within various open and closed depositional systems. The storage types and formations being tested are considered regionally significant and are expected to have the potential to store hundreds of years of CO_2 stationary source emissions.

Accounting that permanent CO_2 storage in geologic formations may not be a viable option for all CO_2 emitters and that this option could result in no environmental benefit at significant cost, the DOE-NETL[4]

[2]http://www.netl.doe.gov/technologies/carbon_seq/natcarb/index.html
[3]http://www.epa.gov/climatechange/Downloads/ccs/CCS-Task-Force-Report-2010.pdf
[4]http://www.netl.doe.gov/technologies/iccs/index.html

is also researching the development of alternatives that can use captured CO_2 or convert it to a useful product, such as a fuel, chemical, or plastic, with revenue from the CO_2 use offsetting a portion of the CO_2 capture cost.

Based on the reasons provided above, CCS has only been effectively proven in small scale projects in specific regions, and is therefore considered technically infeasible for this project.