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June 19, 2020

VIA E-FILE & OVERNIGHT MAIL

Mr. Walter L. Thomas, Jr., Secretary
Alabama Public Service Commission
RSA Union Building
100 North Union Street, Suite 950
Montgomery, AL 36104

RE: Alabama Power Company Petition for Certificate of Convenience and Necessity; Docket No. 32953

Dear Secretary Thomas:

On behalf of Intervenors Energy Alabama and Gasp, please find *Energy Alabama and Gasp's Motion to Supplement the Record* enclosed for filing in the above referenced matter.

This filing is submitted to the Commission through its e-filing system, consistent with the rules and practices of the Commission. The original and one copy are being delivered to the Commission via overnight mail.

Please contact me if you have any questions or concerns regarding the enclosed.

Sincerely,

Keith Johnson

Keith Johnson
Southern Environmental Law Center

Encl.

BEFORE THE ALABAMA PUBLIC SERVICE COMMISSION

IN RE: Petition for a Certificate of	)	
Convenience and Necessity by	)	Docket 32953
Alabama Power Company	)	

ENERGY ALABAMA AND GASP'S MOTION TO SUPPLEMENT THE RECORD

Intervenors Energy Alabama and Gasp ("Intervenors") respectfully submit this Motion to Supplement the Record with new and material information that should be considered by the Alabama Public Service Commission ("Commission") in its disposition of the above-referenced docket.[1] Specifically, the following documentation regarding Southern Company's net-zero carbon goal and Alabama Power Company's ("Alabama Power" or "Company") carbon capture and storage cost estimates for the Barry Unit 8 fossil fuel plant should be considered in the Commission's determination of reasonableness and cost-effectiveness of the Company's proposed resource additions.

During its annual meeting of stockholders on May 27, 2020, more than two months after the hearing's conclusion, Alabama Power's parent Southern Company announced its long-term greenhouse gas emissions reduction goal of net-zero emissions by 2050. Exhibit A, Press Release, Southern Company, Southern Company announces transition to net-zero carbon emissions goal (May 27, 2020), https://www.southerncompany.com/newsroom/2020/may-2020/transition-to-net-zero-carbon-emissions-goal.html. This more ambitious goal replaces Southern Company's previous low to no carbon emissions by 2050 goal. Southern Company plans to meet this new goal through engagement with regulators—like the Commission—and policymakers, among others. The Southern Company statement promises to "incorporate

[1] The Commission has stated that this docket is an ongoing proceeding until it issues the final order. Press Release, Alabama Public Service Commission (June 9, 2020), http://psc.alabama.gov/Releases/2020/Alabama%20Power%20Certificate%20approval_Docket%2032953%20%20Press%20Release_6_9_20%20JAG.pdf.

negative carbon solutions, including technology-based approaches such as direct air capture of carbon." The net-zero carbon goal was announced during the pendency of Alabama Power's Petition for resource additions that will result in over 60% of the Company's overall portfolio being fossil fuel generation, including the Barry Unit 8 fossil fuel plant, whose 40-year life will extend well beyond 2050. Tr. 667:2-4.

To meet the previous low to no carbon goal (and presumably the new goal as well), the Company has stated that the proposed natural gas-fired Barry Unit 8 potentially could burn hydrogen or be equipped with carbon capture and storage (CCS), also known as carbon capture and sequestration. Tr. 406:15-20, 408:1-3, 532:14-21; Bush Rebuttal Test. 16:7-16; Kelley Dep. 202:1-9. Despite these statements, Company witnesses insisted during the March hearing and in prior depositions that they had no cost estimates or analysis for burning alternative fuels or retrofitting Barry Unit 8 with CCS technology. Tr. 406:15-407:11, 408:1-3, 622:10-16; Bush Dep. 80:20-81:8, 82:3-5; Looney Dep. 71:21-72:3.

Intervenors have recently discovered that Alabama Power submitted an air construction permit application to the Alabama Department of Environmental Management for Barry Units 8 and 9 in February 2020,[2] prior to the March 2020 hearing in this docket. Exhibit B, Ala. Power Co., Air Construction Permit Application, Barry Units 8 and 9 Combined Cycle Project (Feb. 2020) (relevant excerpts included in Exhibit B, entirety of application available at http://lf.adem.alabama.gov/WebLink/DocView.aspx?id=104268402&dbid=0). In that application, Alabama Power discussed at length the best available control technology for greenhouse gas emissions, including carbon capture and storage. The application also included a detailed cost estimate of CCS technology for both units of about $322 million on an annual basis,

[2] It is unclear why Alabama Power chose to submit an air permit application for two combined cycle plants at Plant Barry, while it has only requested approval of one such plant in this docket.

which Alabama Power claims is unreasonable. To counsel's knowledge, this information was not produced during discovery, and it was not discussed during the hearing.

If the cost for one unit is half of the cost estimate,[3] the cost of CCS for Barry Unit 8 is estimated at $161 million each year. In addition, Alabama Power stated that the cost estimate is conservative because it is based on a maximum operating scenario, and under normal conditions, carbon emissions would be lower, thereby increasing the cost of CCS on a dollar per ton basis. Exhibit B at 5-29 to -30.

Information about Southern Company's net-zero goal and its cost estimates for adding carbon capture and storage to Barry Unit 8 are directly relevant to Alabama Power's Petition because they go to its reasonableness and cost-effectiveness. Southern Company's new, ambitious net-zero goal makes it all the more likely that, in the future, Barry Unit 8 will either be retrofitted with expensive new technology like the estimated $161 million per year CCS controls or will no longer generate electricity, thus becoming a stranded asset. Either way, the burden will be on ratepayers to pay for the costly retrofit or the costs of a stranded asset.

The Company should not be permitted to downplay the carbon risk inherent in its Petition by suggesting it could later adopt CCS technology for Barry 8, while simultaneously withholding from review relevant and material information bearing on the costs associated with that technology. Contrary to Company witnesses' testimony at the hearing, not only was that information available, it had been submitted to another regulatory body. The Company's CCS cost estimates further throw its claims about the cost-effectiveness of Barry Unit 8 into question and render the Company's economic analysis incomplete and insufficient. Therefore, Intervenors respectfully request that the Commission supplement the record with the attached exhibits.

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[3] Due to the technologies involved, it is our understanding that equipping one unit with CCS would likely cost more than half. Halving the total cost is likely a conservative estimate.

Respectfully submitted this 19th day of June, 2020.

Keith Johnston

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CERTIFICATE OF SERVICE

I hereby certify that on June 19, 2020, I served the foregoing *Energy Alabama and Gasp's Motion to Supplement the Record* via electronic mail to the parties below:

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Keith Johnston

Exhibit A

Southern Company
(/)

Newsroom (/newsroom.html) | 2020 (/newsroom/2020.html) | Southern Company announces transition to net-zero carbon emissions goal

Southern Company announces transition to net-zero carbon emissions goal

May 27, 2020

Southern Company today moved to a long-term greenhouse gas (GHG) emissions reduction goal of net-zero emissions by 2050. The company also reaffirmed its intermediate goal of a 50 percent reduction of GHG emissions from 2007 levels by 2030. These are enterprise-wide goals across all electric and gas operations. Today's action, announced during the 2020 Southern Company Annual Meeting of Stockholders, replaces the low- to no-carbon goal the company unveiled in April of 2018.

Driven primarily by low natural gas prices, and through our regulators, Southern Company has seen a rapid transition of its system's generation fleet. The Southern Company system's carbon emissions have decreased by 44 percent through 2019, and the company now expects to achieve the 50 percent reduction goal well in advance of 2030, and possibly as early as 2025. The company remains a leader in formulating and implementing a comprehensive strategy to reduce GHG emissions and will offer further detail on its progress in a report to be issued later this year.

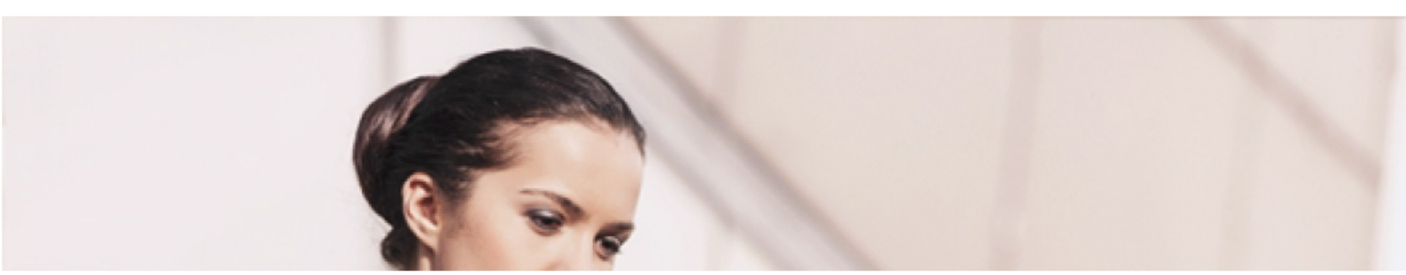
"I continue to be confident that we are prepared and well-positioned to meet the needs of our customers, employees, communities and investors well into the future and will succeed in the transition to a net-zero carbon future," said Tom Fanning, chairman, president and CEO of Southern Company. "As always, we are committed to providing clean, safe, reliable and affordable energy to the customers we are privileged to serve."

To achieve the net-zero goal, the company will continue to reduce GHG emissions and continue our long-term commitment to energy efficiency, but also incorporate negative carbon solutions, including technology-based approaches such as direct air capture of carbon as well as natural methods like afforestation. Since 2018, the interest in decarbonization efforts in the U.S. and beyond – including with Southern Company's board and stakeholders – has evolved to incorporate concepts related to negative carbon solutions.

This long-term, strategic approach is essential to successfully reducing carbon emissions while also maintaining reliability and affordability. The transition of the generation fleet helps ensure energy remains reliable and affordable for customers while also being sensitive to the impact this transition has on communities as well as employees. All of this is executed in the absence of mandates and by constructively engaging with policymakers, regulators, investors, stakeholders and customers to support outcomes that lead to a net-zero carbon future.

More...

(/newsroom.html)



(/newsroom/news-releases.html)

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Exhibit B

Prepared for:
Alabama Power Company
Birmingham, Alabama

Prepared by:
AECOM
Chelmsford, MA
60602366
February 2020

Air Construction Permit Application

Alabama Power Company Plant Barry Units 8 and 9 Combined Cycle Project Mobile County, Alabama

February 2020

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emission control equipment is less effective. Therefore, work practice standards are proposed in lieu of numerical emission limits during periods of transient operation.

5.2.6.1 Startup and Shutdown Operations Overview

During startup and shutdown conditions, the emissions control features (DLN combustor, SCR system, and oxidation catalyst) are less effective than under the steady state conditions that occur during normal load operations, between minimum load and full load. In particular, the SCR and oxidation catalyst systems require time to reach minimum operating temperatures in order to effectively control emissions. The periods of startup and shutdown are defined below.

Startup – the period from when the combustion turbine is started until it reaches the minimum emissions compliance load (MECL)

Shutdown – the period when the load on the combustion turbine is decreasing from the MECL

5.2.6.2 Startup and Shutdown BACT

The following work practice standards are proposed as BACT for NOx, CO, and VOC during periods of transient conditions which include startup and shut down:

- Take all reasonable actions to minimize the magnitude and duration of elevated emission conditions during these transient periods
- Employ good operation and maintenance practices, including on associated pollution control technologies
- Comply with emission monitoring, recordkeeping, and reporting requirements
- During startup, initiate reagent flow in the SCR once the flue gas reaches the requisite temperature for NOx control
- During shutdown, maintain reagent flow in the SCR until the flue gas temperature falls below the requisite temperature for NOx control
- During startup or shutdown of the duct burner, maintain reagent flow in the SCR consistent with technological limitations, manufacturer's specifications, and good engineering and maintenance practices for the SCR to minimize emissions to the extent reasonably practicable

5.2.7 BACT for GHG Emissions

5.2.7.1 Formation

Greenhouse gases (GHGs) emitted due to the combustion of natural gas in a combined cycle unit include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Based on the emission calculations summarized in Section 3.0, CO_2 represents 99.9% of the GHG emissions from a combined cycle unit on a carbon dioxide-equivalent (CO_2e) basis.

5.2.7.2 Step 1 - Available GHG Control Technologies

The only post-combustion technology for controlling CO_2 emissions is carbon capture, utilization, and storage (CCUS). Accordingly, CO_2 emission controls evaluated for potential availability for the combined cycle units are 1) energy efficiency, 2) use of low carbon fuels, and 3) CCUS. Each of these control alternatives are discussed in the following sections.

Combined Cycle Unit Energy Efficiency

CO_2 is a product of combustion of fuels containing carbon, which is inherent in any power generation technology using fossil fuel. The theoretical combustion equation for CH_4, for example, is:

$$CH_4 + 2\ O_2 \rightarrow CO_2 + 2\ H_2O$$

Consequently, CO_2 emissions are the essential and intended product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by impurities or by imperfect combustion. As a result, the only effective means to minimize the amount of CO_2 generated by a fuel-burning unit is through maximization of efficient use of the combustion heat, thereby resulting in the lowest quantity of fuel used per product. For a combined cycle unit, fuel efficiency is expressed as heat rate (i.e., Btu/kWh), and high fuel efficiency corresponds to a low heat rate. Minimizing the amount of fuel required to produce a given amount of electrical power output results in the lowest amount of CO_2 generated during the combustion process. Efficiency in a combined cycle unit can be achieved through good engineering design and good combustion/operational practices.

Design - Combined-cycle units operate based on a combination of two thermodynamic cycles: the Brayton and the Rankine cycles. A CT operates on the Brayton cycle, and the HRSG and steam turbine operate on the Rankine cycle. The combination of the two thermodynamic cycles allows for the very high fuel efficiency that is associated with combined-cycle units.

The natural gas CT technology proposed for the project is the high efficiency Mitsubishi M501JAC CT. The high-efficiency primary components of the turbine, including the upgrade components to be installed after the first turbine inspection, result in high overall efficiency. In addition to efficient turbine components, CTs are designed with evaporative inlet air cooling or inlet fogging. These devices are used during higher ambient air temperature operating conditions in order to lower the temperature and increase the density of the inlet combustion air. Increasing air density reduces the power required to compress the air before it is used in combustion, thus increasing the overall energy efficiency of the CT on hot days.

One of the primary causes of efficiency loss for a combined cycle unit is CT compressor fouling. As a preventive measure, CTs are designed such that inlet air to the CT passes through a high efficiency filtration system, which reduces the contaminants that cause compressor fouling.

CTs have high operating temperatures. The high operating temperatures are a result of the heat of compression in the compressor along with the fuel combustion in the burners. To minimize heat loss from the CT and protect personnel and equipment around the machine, CTs are designed with insulation blankets applied to the CT casing. These blankets minimize heat loss through the CT shell and help improve overall efficiency of the machine.

Finally, CTs are designed with sophisticated instrumentation and controls to automatically manage operation of the CT. The control system is a digital-type, is supplied with the CT, and controls all aspects of the turbine's operation, including the fuel flow rate and burner operations to achieve high combustion efficiency. The control system monitors operation of the unit and modulates fuel flow and turbine operation to achieve optimal high-efficiency, low-emissions performance under all operating cases.

Likewise, the Rankine cycle HRSGs are efficient by design. These heat exchangers are designed to capture as much thermal energy as possible from CT exhaust gases and duct burners. HRSGs take the heat from the CT exhaust and use this heat to convert boiler feed water into steam, which is used to drive a steam turbine. Maximizing steam generation increases the steam turbine's power generation, which maximizes overall plant efficiency. One aspect of the HRSG design in maximizing this waste heat conversion is the use of insulation on all gas path surfaces exposed to ambient air. Insulation minimizes heat loss to the ambient air, thereby improving the overall efficiency of the HRSG. Insulation is applied to the HRSG panels that make up the shell of the unit, to the high-temperature steam and water lines, and typically to the bottom portion of the stack.

Good Combustion and Maintenance Practices - CTs have regularly scheduled maintenance programs. These maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. As the CT is operated, the unit experiences degradation and some loss in performance. The CT maintenance program helps restore the recoverable lost performance. The maintenance program schedule is determined by the number of hours of operation and/or turbine starts. There are three basic maintenance levels: combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to maintain highly efficient operation. Also, while compressor fouling is minimized by design, to address compressor fouling that does occur, the compressor is cleaned periodically using online and offline water wash systems.

HRSG maintenance is also important. HRSGs are made up of a number of tubes within the shell of the unit that are used to generate steam from the high temperature CT exhaust gas. To maximize this heat transfer, the tubes and their extended surfaces need to be as clean as possible. Fouling of the tube surfaces impedes the transfer of heat. Fouling occurs from the constituents within the exhaust gas stream. Although filtration of the inlet air to the CT minimizes fouling, cleaning of the tubes is performed during periodic outages. By reducing the fouling, the heat transfer efficiency of the HRSG tubes is maximized.

Finally, minimizing the number and quantity of steam vents and the timely repair of steam leaks is important in maintaining the plant's efficiency. A combined-cycle unit has several locations where steam is vented from the process, including the deaerator vents, blowdown tank vents, and vacuum pumps/steam jet air ejectors. These steam vents are necessary to improve the overall heat transfer within the HRSG and condenser by removing solids and air that potentially reduce the efficiency of the heat transfer surfaces. Minimizing the number and quantity of steam vents and repairing steam leaks in a timely manner is important in maintaining the plant's efficiency.

Clean/Low Carbon Fuels

The CAA includes clean fuels in the definition of BACT; therefore, clean or low carbon fuels should be considered as a potentially available control technology for GHG emissions – provided they would not redefine the proposed source. GHG emissions from fuel combustion depend on the carbon content of the fuel. On a heat input basis, combustion of natural gas results in lower GHG emissions than the combustion of other fossil fuels.

Carbon Capture, Utilization, and Storage

The only potential post-combustion control technology for CO_2 emissions is CCUS. CCUS is an integrated suite of technologies that has the potential to work together to capture (separate and purify) CO_2 from stationary source emissions, compress and transport it to a suitable location, and then either use it or pump it into deep underground geologic formations for safe, secure, and permanent storage. Geologic storage refers specifically to the process by which CO_2 is pumped underground into rocks such that it is permanently trapped so it cannot enter the atmosphere. Captured CO_2 can also be transported and pumped into oil fields and utilized for enhanced oil recovery (EOR).

5.2.7.3 Step 2 - Technical Feasibility of GHG Control Technologies

The first two potentially available technologies identified above—energy efficiency and low carbon fuels—are technically feasible for the proposed units. However, for CCUS to be technically feasible, each individual step in the process must be technically feasible and the integrated suite of components must also be technically feasible such that each component integrates to work together without interfering with the essential operation of the units. As such, any potential barriers to the successful integration of these components must be considered in determining whether CCUS is technically feasible for the proposed units.

To date, CCUS has not been demonstrated at commercial scale on a natural gas-fired combined cycle (NGCC) unit. In an effort to advance technology development, Research & Development (R&D) programs are currently being funded by the United States Department of Energy (DOE) in cooperation with technology and industry partners to develop options, reduce project uncertainty, and improve technology deployment costs and performance. According to DOE:

> *The successful development of advanced CO_2 capture technologies is critical to maintaining the cost-effectiveness of fossil fuel-based power generation. Today, there are commercially available First-Generation CO_2 capture technologies that are being used in various small-scale industrial applications. At their current state of development, these [CO_2 capture] technologies are not ready for widespread deployment on fossil fuel-based power plants for three primary reasons. DOE is focused on supporting research and development (R&D) of novel technology solutions that address the three major issues with existing commercial CO_2 capture technology.*
>
> - *Reducing the impact of CO_2 capture on power generating capacity;*
> - *Scaling up novel CO_2 capture technologies to the necessary size for full-scale deployment at fossil energy power system; and*
> - *Improving the cost effectiveness of novel technologies for CO_2 capture so that fossil-based systems with carbon capture are cost competitive.*
>
> *. . .The Carbon Capture Program's approach to achieve these goals is to utilize a combination of developments in process chemistry, new chemical production methods, novel process equipment designs, new equipment manufacturing methods, and optimization of the process integration with other power plant systems (e.g., the steam cycle, cooling water system, carbon dioxide compression, etc.). Additionally, advances in boiler/gasifier technologies, materials of construction, process stream handling, heat integration, compression technologies, gas cleanup and separation, and power cycle technology under development within the Department's Clean Coal Research Program provide synergistic benefits are also required to meet program goals.*[15]

Notably, these technical challenges are perhaps more pronounced for gas-fired generation, due to unique issues associated with gas combustion at combined-cycle units and the previous focus on steam boilers. As stated by DOE:

> *Because of the many similarities between natural gas and coal fired power systems, DOE's current CCUS program does address many natural gas issues. However, because natural gas CCUS faces some unique issues, more [research, design, development, and*

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[15] U.S. Dep't of Energy, *Carbon Capture R&D*, https://www.energy.gov/fe/science-innovation/carbon-capture-and-storage-research/carbon-capture-rd (last visited Jan. 24, 2020).

> *demonstration] RDD&D is needed to focus on natural gas CCUS at a relevant scale. DOE is prepared to support a demonstration program to evaluate the adoption of these technologies and to reduce the cost of carbon capture for natural gas power systems.*[16]

EPA has likewise recognized the differences between coal-fired and gas-fired units in questioning whether full or partial CCUS is technically feasible for NGCC units. In light of those concerns, EPA rejected CCUS in determining the best system of emission reduction for GHG emissions from NGCC units in 2015. Specifically, EPA stated the following:

> *[T]he CO_2 concentration in the flue gas of a natural gas combustion turbine is much lower (usually approximately 4 volume percent) than the CO_2 concentration in the flue gas stream of a typical coal-fired plant (which is approximately 16 volume percent for a supercritical pulverized coal or circulating fluidized bed unit) and of the syngas of an IGCC unit (in which CO_2 can be as high as 60 volume percent). Therefore, the overall amount of CO_2 that can be captured in a CCS project is likely lower. Finally, unlike Subpart Da affected facilities, where there are full-scale plants with CCS that are currently under construction or in advanced stages of development, the EPA is aware of only one demonstration project, which is an approximately 40 MW slip stream installation on a 320 MW NGCC unit.*[17]

As previously mentioned in Section 4.4.7, EPA promulgated 40 CFR Part 60, Subpart TTTT which applies to new fossil fuel fired electric generating units including natural gas-fired combustion turbines. In promulgating these standards, EPA rejected CCUS as the best system of emission reduction for natural gas-fired combustion turbines because they did not have sufficient information to determine whether implementing CCUS was technically feasible.[18] In addition, EPA noted that the DOE has not yet funded a CCUS demonstration project for a natural gas-fired combined cycle unit and no natural gas-fired combined cycle CCUS demonstration projects are operational or being constructed in the United States. EPA has also proposed to reverse its prior conclusion that partial capture and sequestration is the best system of emission reduction for new coal-fired power plants, and in that action EPA did not propose any changes to its prior determination regarding the technical feasibility of CCUS for new combustion turbine facilities.[19] As part of its proposal to amend 40 CFR Part 60, Subpart TTTT, EPA concluded "…that CCS is not adequately demonstrated in certain key respects…" including availability of geologic sequestration sites, the scarcity of water needed for CCUS in certain areas of the country, and ongoing issues with successful demonstration of carbon capture technologies. Accordingly, the Agency revised its previous conclusion that partial CCUS represented the best system of emission reduction (BSER) for control of GHG emissions from newly constructed EGUs.[20]

The technical feasibility of each component of a CCUS system is discussed further below.

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[16] U.S. Dep't of Energy, *Carbon Capture Opportunities for Natural Gas Fired Power Systems*, https://www.energy.gov/sites/prod/files/2017/01/f34/Carbon%20Capture%20Opportunities%20for%20Natural%20Gas%20Fired%20Power%20Systems_0.pdf (last visited Jan. 24, 2020).

[17] 79 Fed. Reg. 1,430, 1,485 (Jan. 14, 2014).

[18] 80 Fed. Reg. 64,510, 64,612 (Oct. 23, 2015).

[19] 83 Fed. Reg. 65,424, 65,424 (Dec. 20, 2018).

[20] *Id.* at 65,441.

CO_2 Capture

CO_2 capture is the first step in post-combustion control of CO_2 through CCUS. Capture is the engineered process of separating CO_2 from flue gas or upstream fuel sources. CO_2 gas separation technologies have been developed and employed in the industrial sector (e.g., petroleum refining and natural gas purification) for commercial purposes for more than 70 years.[21] Also, CO_2 capture on a small scale has been happening for many years in the petroleum, ethanol, and industrial chemical industries. While having been deployed for many years in the industrial sector for commercial uses, the technology has not been deployed to date at commercial-scale as an environmental control technology. CO_2 capture is being evaluated for emissions reductions from industrial facilities such as cement and steel manufacturing, coal-fired power plants, and natural gas-fired power plants, but it has never been installed on a commercial- scale NGCC power plant. NGCC power plants inherently emit less CO_2 than other fossil fuel generation sources such as coal or petroleum systems, so capture technologies for NGCC systems have not historically been used to generate a CO_2 stream for commercial purposes nor have they been the focus of R&D for CO_2 capture for GHG emission reductions.

Smaller-scale carbon capture systems have been demonstrated on several power generation facilities as shown in Table 5-1. All but one of these systems have been on coal-fired EGUs.

Table 5-1: Power Generation Units with CCS in North America at Commercial Scale

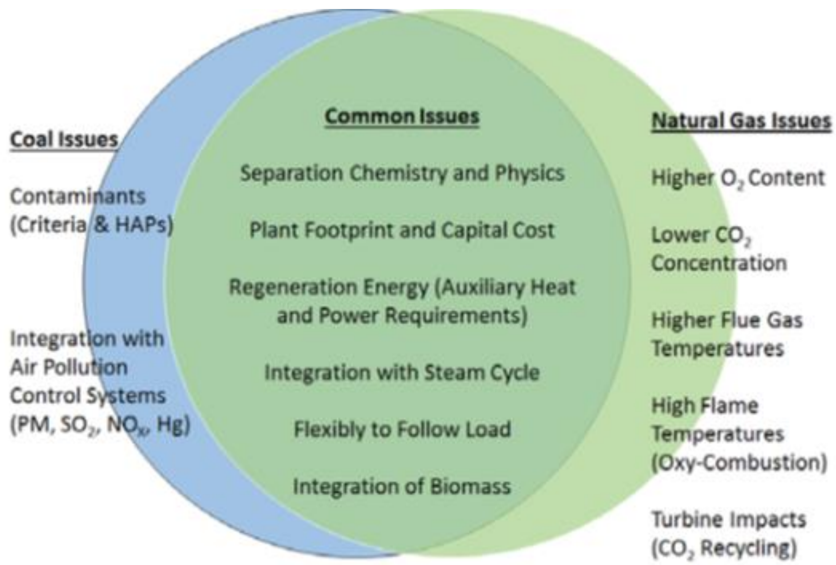
Project	Country	Fuel Type	Supplier/Technology	Tonnes CO_2 Captured per day	Project Start Date
Bellingham	U.S.	Natural gas CC (40 MW slipstream)	Fluor/Econamine FG PlusTM solvent	330	1991 - 2005
Mountaineer	U.S.	Coal boiler (20 MW slipstream)	Alstom/Ammonia (chilled)	300	2009 - 2011
Plant Barry	U.S.	Coal-fired boiler (25 MW slipstream)	MHI/KM CDR Process® and KS-1™ solvent	500	2011 - 2015
Trona	U.S.	Coal-fired boiler (108 MW)	McGee/ABB Lummus Crest/MEA solvent	800	1978 - present
Boundary Dam	Canada	Coal-fired boiler (110 MW)	Shell Cansolv/DC-103 solvent	2,740	2014 – present
Petra Nova	U.S.	Coal-fired boiler (240 MW slipstream)	MHI/KM CDR Process® and KS-1™ solvent	4,800	2016 - present

[21] *Report of the Interagency Task Force on Carbon Capture and Storage* (Aug. 2010), https://www.epa.gov/sites/production/files/2016-08/documents/ccs-task-force-report-2010.pdf (last visited Jan. 24, 2020).

The Bellingham NGCC project in Massachusetts operated from 1991-2005 to capture CO_2 for use in the food industry rather than as an environmental control system. Operating for this purpose allowed the carbon capture system to function essentially independently from the NGCC, diminishing the effects of power cycle fluctuations on carbon capture operations, and largely eliminating the impacts of outages in carbon capture equipment on power production.

Although, as shown in the table above, the majority of post-combustion carbon capture R&D has been done on coal-fired applications to date, the U.S. Department of Energy/National Energy Technology Laboratory (DOE/NETL) has been expanding its focus to all fossil fuel power generation and industrial carbon capture. Much of the CO_2 capture R&D is applicable to natural gas combined cycle units and to the industrial sector such as refineries, ethanol, cement, and steel plants. However, the lower CO_2 concentration in NGCC flue gas dictates that any solvent-based CO_2 absorber must be sized comparatively larger than the one used in a coal capture system; or for a membrane system, more energy and membrane area are required. (See Figure 5-1) NGCC flue gas also has higher oxygen content than other combustion source flue gases, which may cause faster rates of oxidative degradation to solvents.

Figure 5-1: Comparison of Coal and Natural Gas CCUS Issues[22]



Amine solvent is the most developed technology for post-combustion carbon capture. DOE is working on transformational technologies in all areas such as solvents, sorbents, membranes, hybrid, and cryogenic capture systems. As explained by the Fossil Energy Research and Development (FER&D) program, "FER&D will continue to focus on CCS and activities that increase the efficiency and availability of advanced power systems integrated with CCS."[23] This is evident from the recent DOE

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[22] U.S. Dep't of Energy, *Carbon Capture Opportunities for Natural Gas Fired Power Systems*, https://www.energy.gov/sites/prod/files/2017/01/f34/Carbon%20Capture%20Opportunities%20for%20Natural%20Gas%20Fired%20Power%20Systems_0.pdf (last visited Jan. 24, 2020).

[23] U.S. Dep't of Energy, *Carbon Capture, Utilization, and Storage: Climate Change, Economic Competitiveness, and Energy Security* (Aug. 2016), https://www.energy.gov/sites/prod/files/2016/09/f33/DOE%20-%20Carbon%20Capture%20Utilization%20and%20Storage_2016-09-07.pdf

awarded projects and work in many fronts including 1) Front-End Engineering Design (FEED) studies, 2) expansion of the National Carbon Capture Center (NCCC) managed by Southern Company to include testing for natural gas power plants, and 3) large pilot-scale projects at Technology Centre Mongstad (TCM) to simulate NGCC gas conditions. These efforts include nine FEED studies for CO_2 capture systems on both coal and natural gas power plants, with four being performed for retrofit of NGCC power plants with CCS described below:

- Bechtel National will perform the FEED study for a retrofit 2x2x1 NGCC to Panda Energy Fund's plant in Texas with a non-proprietary solvent.
- Electric Power Research Institute will conduct a study for a retrofit on California Resources Corporation's 550 MWe Elk Hills Power Plant (NGCC unit) using Fluor's amine based Econamine FG Plus process to capture 75% of the CO_2 produced.
- Southern Company will complete a study for installation of a Linde-BASF solvent process on an existing NGCC plant in the Southern system.
- The University of Texas at Austin will do a FEED study with the Piperazine Advanced Stripper process at the Mustang Station of Golden Spread Electric Cooperative in Texas.

Based on the lack of commercial deployment at similar NGCC units and barriers to applying second generation research to similar commercial scale NGCC units, carbon capture is technically infeasible for this application.

CO_2 Compression and Transport

In order for captured CO_2 to be permanently sequestered or geologically stored, it must first be compressed "from near atmospheric pressure to a pressure between 1,500 and 2,200 psia . . . ."[24] While compressing CO_2 is feasible, it is extremely energy-intensive and expensive. To reduce the energy intensity related to compression, DOE is evaluating various compression concepts using computational fluid dynamics and laboratory testing that will lead to development of prototypes and field testing. Their research efforts include "development of intra-stage versus inter-stage cooling, fundamental thermodynamic studies to determine whether compression in a liquid or gaseous state is more cost-effective, and development of a novel method of compression based on supersonic shock wave technology."[25]

Some pipelines exist today that transport compressed (dense-phase) CO_2. Since the 1970s, CO_2 has been transported in pipelines to oil fields for use in enhanced oil recovery (EOR) operations. The majority of this CO_2 has been sourced from naturally occurring underground geologic deposits because off-takers of CO_2 transported for use in EOR operations require steady-state production of CO_2.[26] Naturally occurring geologic deposits of CO_2 provide this steady delivery of CO_2. In contrast, the intermittent operation of power plants means that the transportation of CO_2 captured from those power plants is discontinuous and unpredictable. Additionally, existing CO_2 pipelines are not considered to be common carrier (open access) pipelines and are dedicated, with limited capacity, to accommodate private oil industry CO_2-EOR projects. As such, these existing pipelines were not

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[24] NETL, *DOE/NETL Carbon Dioxide Capture and Storage RD&D Roadmap* (Dec. 2010), https://www.netl.doe.gov/File%20Library/Research/Carbon%20Seq/Reference%20Shelf/CCSRoadmap.pdf

[25] U.S. Dep't of Energy, *A Review of the CO_2 Pipeline Infrastructure in the U.S.* (Apr. 21, 2015), http://energy.gov/sites/prod/files/2015/04/f22/QER%20Analysis%20-%20A%20Review%20of%20the%20CO2%20Pipeline%20Infrastructure%20in%20the%20U.S_0.pdf.

[26] Melanie D. Jensen, et al., *Operational Flexibility of CO_2 Transport and Storage*, 63 Energy Procedia 2715-2722 (2014), *available at* https://reader.elsevier.com/reader/sd/pii/S1876610214021092?token=70E82B8033A2B829AA2BFCC09057DCD9BA9342E54B9BAF82207EA43021E7A5E22AD99271091071189B0D6E325F938146.

designed to accommodate the intermittent flow of CO_2 from power plants. As a consequence, for CO_2 compression and transport to be a technically-viable component of CCUS, new CO_2 pipelines for commercial-scale capture operation would be required to be developed.

Still, construction of a CO_2 pipeline would be like construction of a natural gas pipeline, with applicable regulations, requiring the same attention to design, monitoring for leaks, and protection against overpressure, especially in populated areas. The proposed NGCC units at Plant Barry would need to construct a CO_2 pipeline to a suitable location where injection for saline formation storage or CO_2-EOR would take place if it were to pursue CCUS as a CO_2 control option. While it may be technically feasible to construct a CO_2 pipeline, considerations regarding the land use and availability need to be made. Based on experiences in the CO_2-EOR industry, compression and transport of CO_2 is considered technically feasible

CO_2 Geologic Storage Options

The pumping of CO_2 into deep geological formations or the utilization of the CO_2 for EOR are the last steps of the CCUS process. Both processes can lead to the long-term secure storage of CO_2. These storage operations can include pumping into a wide range of geologic formations including deep saline reservoirs, active and abandoned oil and gas fields, and other rock formations such as un-mineable coal seams and basalt formations. There are no un-mineable coal seams or basalt formations in proximity to the proposed NGCC units at Plant Barry, so these formations are not feasible as storage options in this case. While a few coal seams in North Alabama have been tested as potential storage sites, CO_2 storage in subsurface coal beds in not further considered in this analysis because of the greater distribution and storage capacity of CO_2 storage resources available in deep saline formations in closer to Plant Barry.

While active oil fields are present in South Alabama, no CO_2-EOR operations are currently active in the State of Alabama. The transition of an existing oil field to a CO_2-EOR operation requires significant capital expenditures[27] and permitting of the CO_2 pumping operations. Moreover, not all oil fields are amenable to CO_2-EOR operations. Significant feasibility studies would need to be planned to determine if CO_2-EOR would be a cost-effective option for recovery of oil in each field being considered. The potential for an oil company to engage in an agreement to use CO_2 for EOR also largely depends on the price of oil. As such, using CO_2 for EOR operations is not currently feasible for this application.

Alternatively, deep saline formations are present in the geologic subsurface in South Alabama that have been assessed to be feasible for safe geologic storage of CO_2. Safe, secure, and permanent geologic storage in deep saline formations has been successfully performed throughout the world and in the United States but requires the presence of a sufficiently permeable rock formation (typically sandstone or carbonate) which is sealed by rocks on top that have a very low permeability. These formations need to be at least 1 kilometer (km) deep to ensure that the CO_2 is stored as a dense phase, also called a supercritical fluid. To protect underground drinking water aquifers, CO_2 storage is only permitted in saline formations that are saltier than 10,000 parts per million (ppm) total-dissolved-solids per the EPA Class VI Underground Injection Control (UIC) regulations. The geologic seal (typically a shale formation or chalk) must be continuous over the entire area where the CO_2 is stored and free of defects such as permeable faults, fractures, or leaky wellbore penetrations. Additional considerations include an assessment of the risks of induced seismicity and the potential for CO_2 or brine leakage through preexisting boreholes. Brine is water containing dissolved salts that naturally

[27] Armpriester, Anthony. *W.A. Parish Post Combustion CO2 Capture and Sequestration Project Final Public Design Report*. United States: N. p., 2017. Web.

exists in a rock formation. To evaluate formations for suitability, extensive drilling and site characterization must be performed to certify a site to be geologically suitable for long-term geologic storage.

The CO_2 storage capacity estimates for the United States have been assessed by both the United States Department of Energy (DOE) and the United States Geological Survey (USGS). Both assessments indicate a large potential for storage, with median estimates ranging from 3,000 to 8,600 billion metric tons of CO_2. The economic potential, often referred to as a “storage reserve” is likely to be significantly lower, but how much lower is not fully evaluated. Regardless, conservative estimates are large compared to the amount of CO_2 emitted in the United States each year[28] - suggesting that storage capacity is unlikely to be a limiting factor in the United States.

Since CO_2 capture technology has to date not been applied to a NGCC power plant, there are currently no CO_2 geologic storage projects related to CO_2 sourced from NGCC power plants. Saline formation injection demonstration projects in the US and which Southern Company was a research participant include:

Plant Daniel Pilot Injection Project - This project was conducted by DOE’s SECARB Partnership and the Electric Power Research Institute (EPRI) and involved drilling one injection well and one observation well into the Tuscaloosa Formation (a deep saline formation) at Mississippi Power’s Plant Daniel. Approximately 3,000 tons of CO_2 were pumped into the injection well into a deep saline formation approximately 8,500 feet below ground surface (bgs) and monitored in the adjacent monitoring well. The pumping was completed in 2008, and monitoring was completed in 2010. The project included site characterization, permitting, CO_2 pumping operations, and monitoring of the small amount of CO_2 pumped into the subsurface.

Plant Barry Anthropogenic CCUS Demonstration/SECARB Phase 3 - Southern Company built and operated a 25 MW coal slipstream amine post-combustion capture plant at Plant Barry beginning in 2011. CO_2 subsurface pumping operations began in 2012 and the pumping operations concluded in 2014. The project was decommissioned in 2015. The injection wells have been plugged and abandoned. The capture project provided CO_2 for SECARB funded storage research. The project included drilling two injection wells and two observation wells into the Paluxy Formation (a deep saline formation) located in Citronelle Dome, geologically above the Citronelle Oil Field in South Alabama. The project pumped nearly 120,000 tonnes of CO_2 over three years. The project included construction and operation of a 12-mile pipeline that connected Plant Barry to the Citronelle Dome injection site. The project informed DOE and industry how effective monitoring and verification protocols for geologic storage could be deployed in the field.

Kemper County Energy Facility/Phase II CarbonSAFE - In Kemper County Mississippi, a DOE project awarded to the Southern States Energy Board (SSEB) provided funding for the drilling of three deep saline geological characterization wells to evaluate the facility of the storage of CO_2 in three separate saline reservoirs under that site. The results were positive in that good rock properties existed for the pumping and long-term safe storage of CO_2 at that site. No CO_2 was pumped as a pilot demonstration with this project. DOE has recently announced additional funding opportunities to continue additional work at sites within the CarbonSAFE program.

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[28] NETL, *FE/NETL CO_2 Saline Storage Cost Model* (Sept. 30, 2017), https://www.netl.doe.gov/research/energy-analysis/search-publications/vuedetails?id=2403.

Other geologic storage projects conducted in Europe, the United States, Canada, Australia, and Japan since 1990 with commercial scale storage operation as listed below in Table 5-2.

Table 5-2: Commercial-Scale Saline Formation CO_2 Pumping and Storage Projects

Owner/Operator	Location	CO_2 Amount Sequestered
In-Salah (a joint venture of Solargraph, BP, and Statoil)	Algeria in North Africa	1 million tons per year since 2004 <u>CO_2 source</u>: natural gas production upgrading operations
Statoil (Norwegian oil company)	Utsira Sandstone, saline formation under the North Sea associated with the Sleipner West Heimedel gas reservoir	Approximately 1 million tpy; equivalent to the output of a 150 MW coal-fired power plant <u>CO_2 source</u>: natural gas production upgrading operations
Southeast Regional Carbon Sequestration Partnership	Cranfield oil field in Mississippi	Approximately 100,000 tons per month (more than 6.6 million tons since 2010) <u>CO_2 source</u>: Jackson Dome naturally occurring geologic source
Midwest Regional Carbon Sequestration Partnership	Mount Simon Saline Sandstone Formation in Illinois	Approximately 9,490,000 tons since 2011 <u>CO_2 source</u>: ADM ethanol plant
Shell Canada, Chevron Canada and Marathon Oil Sands	Fort Saskatchewan, Alberta, Canada	Approximately 1 million tpy, beginning November 2016 <u>CO_2 source</u>: hydrogen plant

Although geologic research storage projects involving Southern Company and other entities exist, it is noted that large commercial scale storage projects from NGCC plants do not currently exist.

<u>Other Feasibility Considerations</u> - When CO_2 is pumped into a geologic formation, it occupies small voids within the geologic structure known as "pore space." Before pumping CO_2 into the subsurface for geologic storage, the storage operator must own the pore space, have permission from the owner, or otherwise have the right to use the pore space. The laws concerning property rights over pore space is a basic concern of state law rather than federal law and varies from state to state. The issue of pore space property rights is complicated by the fact that for a large CO_2 storage project, the CO_2 plume may extend over many square miles, and impacts to formations may extend over an even larger area. For large projects, multiple property or pore space owners are likely to be involved in the process of identifying and acquiring pore spaces rights. Addressing issues related to property rights and competing uses of the subsurface mineral rights could have an impact on the feasibility of CO_2 storage. Currently the State of Alabama does not have any clear defining laws addressing the potential legal issues related to pore space facing large commercial-scale injection of CO_2 for long-term geologic storage. For example, the ownership of property and mineral or groundwater rights relevant to use of pore space for long-term geologic storage are not well-established. Fee simple property rights may not be available, and subsurface rights divorced from fee and surface rights are complex. As a result, CO_2 storage in a geologic formation lies beyond the direct control of the source in most cases.

In addition to pore space ownership, there are issues associated with CCUS related to long-term responsibility for the stored CO_2. Some states have enacted laws governing these issues, but they vary. This is a problem for projects that operate in states without such laws and for projects that cover multiple states. Some states are beginning to address these issues, but no clarification has been made at a State level in Alabama to address the issues.

The closest geologic structure suitable for large volume geologic storage sourced from Plant Barry specifically, is the geologic structure named Citronelle Dome located approximately 12 miles from Plant Barry. As described previously, CO_2 has been pumped into the Citronelle Dome for field testing. It has been demonstrated to be a suitable storage structure for large-volume CO_2 storage. Pumping operations ceased in September 2014, with post-project monitoring of the 120,000 metric tons of CO_2 pumped for storage. However, Alabama Power has no legal rights to any pore space in the Citronelle Dome.

In light of the uncertainties regarding commercial scale CO_2 pumping and storage, including the long-term liabilities, the absence of EOR operations in the state, and the lack of legal access to pore space in the Citronelle Dome, CO_2 storage is not considered technically feasible in this application.

Integration

Regardless of the potential availability or feasibility of the individual components of CCUS, the integration of these systems at a commercial scale NGCC unit must also be evaluated. As an initial matter, no integrated CCUS system has ever been constructed to serve a commercial scale NGCC. And although there are two CCUS systems currently in operation at coal-fired generating facilities, only one of those is fully integrated: the SaskPower Boundary Dam CCUS Project. The Boundary Dam project processes essentially all of the flue gas from the 110 MW Boundary Dam coal-fired power station Unit 3. Boundary Dam experienced operational problems from its initial opening in 2014, including significant challenges in 2017 that led to lengthy outages and a much lower capture rate than originally anticipated. Operations have steadily improved since that time but remain below design CO_2 production levels. However, despite receiving $240 million from the Canadian federal government, the economic viability of the $1.5 billion 110-MW project remains questionable - an April 2016 Parliamentary Budget Office report found that CCUS at Boundary Dam doubles the price of electricity produced by this facility. Moreover, after that study was released, the initial operational challenges forced the facility to renegotiate its EOR contracts resulting in a significant reduction in annual revenue over the life of the project.

The only other commercial scale CCUS system currently in operation is the Petra Nova commercial demonstration project at the W.A. Parish coal-fired power plant Unit 8, which began operation in January 2017. The facility is not an integrated system because it operates on a slip stream of the unit's total flue gas. Moreover, the project requires an entirely separate natural-gas fired power plant to provide the power needed to operate the carbon capture and compression process. Thus, although the system was designed to capture approximately 33 percent of the CO_2 emitted from Unit 8 (90 percent capture of a 240 MW slipstream from the total 654 MW capacity of Unit 8), the NGCC providing power to the system will emit CO_2 as well, resulting in a lower net reduction in CO_2 emissions. Like Boundary Dam, Petra Nova received significant financial assistance from the government - $167 million from the U.S. Department of Energy - without which the $1 billion project may not have been possible.

The operational success of these two projects is encouraging, but difficulties with integrated CCUS facilities on a larger scale are expected to result from load fluctuations, outages, and CO_2 purity. Also, the reliability of the host-generating unit could be affected by problems associated with the CCUS processes as described below:

- **Loading** - Power plants do not run consistently; their load fluctuates as needed to meet electricity demand, which may affect the CCUS equipment. EOR operations historically have been supplied with CO_2 from some steady source, such as a natural geologic deposit of CO_2 or from a natural gas purification process. The knowledge available on CO_2 sequestration is mostly from EOR operations.
- **Outages** - Power plants experience planned and forced outages. During these outages, the CCUS processes would be suspended. It is unknown how this suspension will affect the injection operations and equipment.
- **CO_2 Purity** - CO_2 streams from power plants may not be the same as CO_2 produced from natural geologic deposits or from natural gas purification processes. It is unknown if CO_2 streams of varying composition will be able to be integrated into the same pipeline network.
- **Reliability** - Reliability of an integrated CCUS system, including the host power plant, will be affected by problems arising in each CCUS process. Because CO_2 capture, transport, and storage have not yet been integrated at a commercial scale NGCC power plant, it is unknown how the three processes will interact with each other and the host plant. For example, it is unknown how problems at the capture unit will affect the pumping and storage operations. Furthermore, if the capture unit fails and the CO_2 pumping process stops, there could be implications to the pressure in the geologic storage formation. If CO_2 cannot be pumped, the host generating unit may also not be able to run unless it is able to discharge its CO_2 emissions while the problems in the CCUS processes are addressed. Problems in one CCUS process will affect the operations of other processes and thus impact the reliability of the system and potentially the ability of the host generating unit to deliver reliable power to customers who depend on the end product-electricity.

Close attention to both Petra Nova and Boundary Dam commercial demonstration projects is crucial as they continue to develop operational expertise since there is very limited industry-wide operational experience.

In addition to the projects described above, another example is Southern Company's research project at Alabama Power's Plant Barry Anthropogenic CCUS Demonstration/SECARB Phase 3 project, which began integrated operation in 2012. It was one of the first projects in the world to study the integration of CO_2 capture operations at a coal plant with pipeline transportation and saline reservoir storage. This project was not commercial scale and consisted of CO_2 capture from the flue gas of a coal-fired boiler rather than from a NGCC unit and operation of the generating units was not dependent on operation of the capture system.

Southern Company has been involved in several demonstration projects that provided some experience with the integration of CCUS' three-step process (i.e., capture, compression and transport, and storage/use) on a commercial-scale power plant. However, these projects support the conclusion that CCUS is currently far from an adequately demonstrated CO_2 control technology at commercial scale on a NGCC power generation unit and requires additional research and development prior to full commercial scale implementation.

CCUS is different from other air pollution control technologies, because, if required for compliance, responsibility may need to be shared between multiple parties, not just the power plant owner/operator. For example, if CO_2-EOR is utilized to store CO_2, the power generator will likely have to enter into a contract with a third party to transport the CO_2 and demonstrate storage in the oil field. Under such arrangements where the power plant is dependent on a third party for compliance, there are always risks of contract breeches, dissolution of the contract parties, or other issues, including long-term responsibility of stored CO_2, that cannot be foreseen that could put the ability of the power plant to meet electricity demand at risk.

CCUS Conclusions

As discussed above, CCUS has the potential to reduce CO_2 emissions as a post-combustion control alternative. However, the technology has only been employed at small commercial scale at two coal-fired facilities and the success of those two projects has been limited. To date, CCUS has never been applied at a commercial scale NGCC unit. While each of the individual components of CCUS, including post-combustion capture, compression, pipeline transportation, and injection for storage in geologic formations are under development and in practice in other industries, additional research and development is needed before all of the components can be reliably integrated into a commercial scale power plant that must function efficiently across a range of operating conditions.

As EPA states in its GHG BACT Guidance (2011), "CC[U]S may be eliminated from a BACT analysis in Step 2 if it can be shown that there are significant differences pertinent to the successful operation for each of these three main components from what has already been applied to a differing source type. … Furthermore, CC[U]S may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, considering the integration of the CC[U]S components with the base facility and site-specific considerations."[29] Since significant challenges remain, for which technical solutions are not currently commercially available, CCUS is not technically feasible for the proposed NGCC units.

The elements of CCUS – capture, compression, transport, and storage/or utilization – have been technically demonstrated in various industries, but they have never been integrated and applied at commercial scale on NGCC units in the electric power industry. More effort and research are required to advance CCUS for gas-fired power generation before it can be deemed sufficiently feasible to form the basis of a BACT determination. As the Environmental Appeals Board has confirmed, technologies in the research phase of development or with unresolved technical difficulties in application would not be considered BACT.[30]

Step 2 of the top-down BACT analysis is the elimination of technically infeasible options. EPA considers a technology to be technically feasible if it is available and applicable to the source type under review. A control technology should also be considered technically available or applicable if it has been demonstrated on an exhaust stream with similar physical and chemical characteristics. Based on the above discussion of CCUS, CCUS is eliminated as a technically feasible option as BACT consistent with EPA's regulations and guidance.

5.2.7.4 Step 3 – Ranking of Available GHG Control Alternatives

The technically feasible options include energy efficiency and the use of low carbon fuels. Energy efficiency includes the high thermal efficiency design of the NGCC units as well as the planned upgrade improvements that are part of the project, as described in the previous sections. Accordingly,

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[29] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* (Mar. 2011), https://www.epa.gov/sites/production/files/2015-07/documents/ghgguid.pdf.

[30] In re Cardinal FG Co. 12 E.A.D. 153 (2005).

efficient units and the use of low carbon natural gas fuel are considered the top-level available alternatives for control of GHG emissions from combined cycle units.

5.2.7.5 Step 4 - Economic, Energy, and Environmental Impacts

Because energy efficient designs and the use of low carbon natural gas fuel are inherent in the proposed units, the impacts of those control options need not be evaluated under Step 4 and serve as the baseline against which to compare the cost-effectiveness and other impacts associated with other available control options (See 1990 Draft NSR Workshop Manual, at B.36[31]).

As demonstrated in Section 5.6.2.2 above, CCUS for control of CO_2 from a NGCC unit is not applicable or technically feasible. However, Alabama Power is also providing a cost assessment which independently confirms that CCUS must be rejected as the basis for a BACT determination for the combined cycle units. The costs associated with CCUS can be broken down into the same categories that the CCUS process is divided into: Capture, Compression and Transport, and Storage (or Use). Due to the size of the proposed combined cycle units, the GHG BACT cost analyses presented in Appendix F are based on a dedicated CCUS system for each combined cycle unit. Because the combustion turbines and supplemental duct burners will be capable of operating simultaneously, each CCUS system must be sized to accommodate the total flue gas and CO_2 flow rates from its associated turbine and duct burner.

CO_2 Capture and Compression Costs

CCUS costs can be adequately estimated for purposes of this study using published studies and government resources. The published CO_2 capture and compression costs studies relied upon represent cost on a "CO_2-Captured" basis. The CO_2-captured basis accounts for CO_2 that is removed from the process as a result of the installation and use of a control technology, without including any losses during compression, transport and storage. It is appropriate to use the CO_2 captured monetary estimates because the BACT analysis is based on emissions from a single stack source (e.g., the direct emissions from each combined cycle unit) and does not account for secondary emissions (e.g., the GHG emissions generated from the act of compressing the CO_2 to pipeline pressures).

Accordingly, cost estimates from the 2019 DOE/NETL Cost and Performance Baseline for Fossil Energy Plants Volume 1 (NETL-PUB-22638), the US Energy Information Administration's 2018 Cost and Performance Characteristics of New Generating Technologies: Annual Energy Outlook 2018, and the Global CCS Institute's 2017 Global Costs of Carbon Capture and Storage: 2017 Update were used to evaluate costs per ton of CO_2 captured. Even when narrowed to NGCC technologies, the costs of carbon capture and compression estimates can vary in published studies. Accordingly, three independent studies were evaluated. Notably, these studies are not intended to account for first-of-a-kind issues and costs that will be encountered by the first implementations of such technology at an NGCC. Thus, the cost analysis presented here and in Appendix F is conservative and higher costs are likely. The results of the cost analysis from each study, when adjusted to a consistent operating basis with the proposed units, indicate an average cost for only the capture (and compression) component of CCUS of $69 per ton of CO_2 captured.

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[31] EPA, *Draft New Source Review Workshop Manual*, at B.37 (Oct. 1990) ("When calculating the cost effectiveness of adding post process emissions controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. In other words, emission reduction credit can be taken for use of inherently lower polluting processes.")

CO_2 Transport Costs

The cost of pipeline installation and operation are obtained from the NETL's document Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs in NETL Studies (DOE/NETL-2019/2044) and the associated FE/NETL CO_2 Transport Cost Model. According to this document, the pipeline costs include pipeline installation costs, other related capital costs, and operation and maintenance (O&M) costs.

The closest potential carbon sequestration site to the proposed Project was found at the Citronelle Dome in Alabama, approximately 12 miles from the project location. For cost estimation purposes, a pipeline length of 12 miles is used. The FE/NETL CO_2 Transport Cost Model indicates that a 12-inch diameter pipeline would be appropriate for the projected volume of capture. NETL guidance on pipeline costs yields a final total capital expense associated with pipeline construction of over $17.9 million including 15% contingency and levelized annual O&M costs of over $262,100/year in 2020 dollars. Based on the projected volume of CO_2 capture, this translates to approximately $0.52 per ton of CO_2 captured for transportation costs.

Geological Storage Costs

Cost estimations for geological storage were developed using information and experience gained during the Plant Barry Anthropogenic CCUS Demonstration/SECARB Phase 3 project described previously at the proposed Citronelle Dome storage location. These estimates yield a final total capital expense of over $93.5 million including 15% contingency and levelized annual O&M costs of over $6 million/year in 2020 dollars. Based on the projected volume of CO_2 capture, this translates to approximately $3.78 per ton of CO_2 captured.

Overall Cost of Carbon Capture and Storage

Including the capture and compression costs for CO_2 emissions related to the combined cycle units, the cost to transport from the site, and the cost to sequester the resulting supercritical fluid into an appropriate site is estimated to be $73 per ton of CO_2 captured. Based on the size of the units, this equates to annual costs of $322 million.

This cost is plainly excessive, particularly given that the levelized cost of electricity from natural gas-fired combined cycle generation is reported to be between $183 million and $240 million per year.[32]

Moreover, this CCUS cost analysis is conservative as it evaluates the maximum design-case operating scenarios of the two units. However, under normal operating conditions, CO_2 emissions would be lower than the maximum design-case operating scenario, which will greatly increase the cost of CCUS on a dollar per ton of CO_2 captured.

In this analysis, partial CCUS was also considered. In order to meet an enforceable emissions limit, the initial size of the capture units and the capital investment would likely be similar in order to capture the same amount of CO_2 as the 90% capture CCUS system to account for reliability and performance issues that CCUS would inherently have. The same size capture system is required in order that the NGCC unit would still be able to provide reliable power to the end users when the CCUS system has reliability issues. As such, partial CCUS would be even more expensive per ton of CO_2 removed as the capital investment is the most significant part of the CCUS costs. On the other hand, if a smaller system was installed on each unit for partial CCUS, then the reliability issues associated with CCUS

[32] Lazard's Levelized Cost of Energy Analysis – Version 13.0, Lazard, (November, 2019).

would impact the NGCC's ability to provide reliable power to the end user while meeting an enforceable emissions limit in the same manner as full capture. Regardless, considering the quantity of CO_2 generated, this figure represents an unreasonable cost for GHG control leading to the conclusion CCUS, in addition to be technically infeasible, is cost prohibitive for the proposed project.

In addition to its direct costs, CCUS creates substantial indirect economic, environmental, and energy impacts. The energy impacts of CCUS implementation include the need for additional energy production to support on-site CO_2 compression and purification and further CO_2 compression at the wellhead. Additional combustion sources that emit CO_2 would be necessary to provide energy to these processes. For multiple reasons, the undue burden of applying a technology that has yet to be proven for combustion turbines, and the excessive cost to implement this technology, CCUS is eliminated from further review.

Use of high efficiency turbines, fueled by natural gas and employing good combustion/operating practices are the remaining control technologies and representative of BACT. A search of the RBLC was conducted to identify recently-permitted large natural gas-fired combined-cycle units with BACT determinations for GHGs. The results of this search are provided in Appendix E, Table E-6. A total of 82 natural gas-fired combined-cycle units that meet these criteria were identified. The measures concluded to be representative of BACT are identified in 62 of these listings. A total of 51 listings describe BACT as either energy efficiency or good combustion; an additional nine listings describe the use of low carbon-emitting fuels as BACT.

5.2.7.6 Step 5 – Evaluation of GHG BACT for the Combined Cycle Units

Selection of BACT

Step 5 of the top-down BACT analysis is the selection of BACT. Alabama Power proposes the following as BACT for GHG for the proposed combined cycle units:

- Use of combined-cycle technology,
- CT energy efficiency designs, practices, and procedures, and
- HRSG energy efficiency designs, practices, and procedures.
- Use of natural gas

Proposed GHG BACT Emissions Limit for the Combined-Cycle Unit

Alabama Power proposes a 2,445,022 tpy CO_2e emissions limit per combined cycle unit as GHG BACT for all operating cases, including during periods of startup and shutdown, averaged on an annual basis.

This numerical GHG BACT emissions limit is based on the exclusive use of natural gas in the combined cycle units. Compliance with this numerical GHG BACT emissions limit will be demonstrated by measuring and recording the total heat input to each combined cycle unit expressed in million British thermal units (Btu) per year. CO_2 emissions will be calculated using the methodology for calculating CO_2 emissions under the Acid Rain Program in accordance with 40 CFR 75[33], Equation G-4.

[33] 40 C.F.R. Part 75, App. G.

Annual methane and nitrous oxide emission rates will be calculated using emissions factors as defined in the Mandatory Greenhouse Gas Reporting Rule[34], Table C-2. CO_2e emissions will then be calculated using each GHG pollutant's respective Global Warming Potential (GWP) as defined in the Mandatory Greenhouse Gas Reporting Rule[35], Table A-1.

To ensure the inherent efficiency of each combined cycle unit remains high throughout all operating modes, Alabama Power will also meet an emission limit of 1,000 lb CO_2/MWh average on a gross output basis over a twelve (12) month operating period which is consistent with 40 CFR Part 60, Subpart TTTT[36]. Alabama Power will demonstrate compliance with the proposed emission limitation on an annual basis by measuring/monitoring total natural gas consumption and gross electrical output for each unit. Measuring and monitoring is a viable surrogate to ensure efficient operation during all operating periods. CO_2 emissions will be calculated using Equation G-4 under the provisions of the ARP, 40 CFR Part 75 using the heat input of the natural gas combusted on monthly basis. The total calculated CO_2 emissions on a monthly basis will be divided by the total gross power output in megawatt-hours generated on a monthly basis to obtain a CO_2 emissions rate expressed in pounds per megawatt-hour. A twelve operating month rolling average will be kept for the CO_2 emission rate (lb/MWh-gross).

In summary, Alabama Power proposes GHG BACT limits of 2,445,022 tpy CO_2e emissions limit per combined cycle unit. It is noted, Alabama Power will also meet the 40 CFR 60 Subpart TTTT limit of 1,000 lb CO_2/MWh-gross on a twelve (12) operating month average.

5.3 BACT for Auxiliary Boiler

5.3.1 BACT for Nitrogen Oxides Emissions

5.3.1.1 Step 1 - Available Auxiliary Boiler NOx Control Alternatives

NOx formation mechanisms for combustion sources are discussed in Section 5.2.1.1. The primary front-end combustion control method for boilers is the use of burners that are specifically designed to limit NOx formation. SCR and selective non-catalytic reduction (SNCR) can be used to remove NOx from boiler flue gas once it has been formed.

Low and Ultra Low NOx Burners

Burners specifically designed to minimize thermal NOx formation, generically referred to as Low NOx Burners (LNBs), control the mixing of fuel and air in a pattern that is intended to maintain low flame temperature and oxygen concentration in the flame zone. Some burner designs seek to control the flame shape in order to minimize the reaction of nitrogen in the combustion air with oxygen at the peak flame temperature. Others use air staging and/or fuel staging to develop flames that have fuel-rich and air-rich regions in order to reduce thermal NOx formation. The flame from an LNB is typically elongated compared to the short, intense flame produced by a conventional burner. According to the EPA, LNBs on natural gas-fired sources have emissions that are between 40 and 85% lower than with

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[34] 40 C.F.R. Part 98, Table C-2.

[35] 40 C.F.R. Part 98, Table A-1. GWPs were determined using 40 CFR Part 98 Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1, effective January 1, 2014, which are consistent with ADEM's GWP per ADEM Admin Code R. 335-3 Appendix I.

[36] 40 C.F.R. Part 60, Subpart TTTT, Table 1.

Appendix F

Greenhouse Gas BACT Supplemental Information

Table F-1 Potential CO_2 Emissions from Combined Cycle Units

Emission Factor[1] (lb/MMBtu)	Total Potential Heat Input[2] (MMBtu/hr)	Operating Duration (hr/yr)	Total Potential Emissions[3] (tpy CO_2)
117	9,534	8,760	**4,885,000**[4]

1. From Table C-1 of Subpart C of 40 CFR 98 for Natural Gas
2. Total Heat Input Capacity includes:
   Unit 8 Combustion Turbine 3,939 MMBtu/hr
   Unit 9 Combustion Turbine 3,939 MMBtu/hr
   Unit 8 Duct Burner 828 MMBtu/hr
   Unit 9 Duct Burner 828 MMBtu/hr
3. Emissions (tpy) = EF (lb/MMBtu) * Total Heat Input Capacity (MMBtu/hr) * Operating Duration (hr/yr)
4. See Appendix D, Table D-5 for emissions for one combined cycle unit.

Table F-2 Assumptions Used in CCUS Cost Estimation

Parameters	Value	Unit
Pipeline Length[1]	12	mi
Pipeline Diameter[2]	12	in
Number of Primary and Backup Injection Wells[3]	8	
Number of Pressure Monitoring Wells[3]	4	
Number of Ground Water Monitoring Wells[3]	5	
Uncontrolled Annual CO_2 Emissions[4]	4,885,000	tpy
Control Efficiency[5]	90	%
Annual Captured CO_2 Emissions	4,396,500	tpy
	12,045	tpd

1. Distance from the facility to the nearest potential CO_2 sequestration facility (Citronelle Dome).
2. Determined using *Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs in NETL Studies,* National Energy Technology laboratory, U.S. DOE, DOE/NETL-2019/2044 (August 2019) and FE/NETL CO_2 Transport Cost Model (Excel spreadsheet).
3. Estimates were based on previous site characterization completed through DOE's Southeastern Regional Carbon Sequestration Program (RCSP).
4. Potential CO_2 emissions calculated in Table F-1.
5. 90% CCS Control Efficiency from *Cost and Performance Baseline for Fossil Energy Plants Volume 1*, National Energy Technology laboratory, NETL-PUB-22638 (September 2019). 90% Capture is a common standard to facilitate comparison among various publicly available cost studies.

Table F-3 Total Costs for Carbon Capture

Estimated Annual Captured CO_2[1]	4,396,500	tpy
Cost of CO_2 Capture from Recent NGCC Post Combustion Capture Studies[2]		
Global Costs of Carbon Capture and Storage: 2017 Update, Global CCS Institute (June 2017)[3]	55.28	\$/ton CO_2 captured
Cost and Performance Baseline for Fossil Energy Plants Volume 1, National Energy Technology laboratory, NETL-PUB-22638 (September 2019)[4]	65.25	\$/ton CO_2 captured
Cost and Performance Characteristics of New Generating Technologies: Annual Energy Outlook 2018, US Energy Information Administration, (February 2018)[5]	86.05	\$/ton CO_2 captured
Levelized Annual Total Costs for CO_2 Capture[6]	\$302,747,059	annual additional cost to ratepayers for CO_2 capture

1. Estimated captured CO_2 from Table F-2
2. \$ / ton CO_2 captured for each study was calculated using the increase in levelized cost of electricity (LCOE) in \$/MWh between the non-capture and capture cost estimates divided by the CO2 capture rate (tons/MWh) of the capture case on a constant MWh basis. The LCOE consists of capital, O&M, and fuel components. Total overnight capital costs (MM\$) were converted to levelized annual capital costs (\$/MWh) using the annual MWh output and a fixed charge rate (FCR) that accounts for the weighted average cost of capital (WACC) and depreciation. Annual O&M costs were escalated and levelized using an assumed escalation rate and the WACC. Annual fuel costs were levelized using a projected fuel price forecast and the WACC.
3. The LCOE and \$/ton CO_2 captured published in this study were adjusted from 85% capacity factor to 100% to align with permitting application. The study FCR was based on funding with 40% debt and 60% equity and an after tax WACC of 8.74%
4. The LCOE and \$/ton CO_2 captured published in this study were adjusted from 85% capacity factor to 100% to align with the permit application. The study FCR was based on funding with 55% debt and 45% equity and an after tax WACC of 6.54%
5. The LCOE and \$/ton CO_2 captured published in this study were adjusted from 85% capacity factor to 100% to align with the permit application. The study did not provide financing assumptions so a typical investor-owned-utility assumption of 60% debt, 40% equity, and an after tax WACC of 7.7% was applied. *Lazard's Levelized Cost of Energy Analysis – Version 13.0*, Lazard, (November, 2019).
6. Estimated Annual Total Costs for CO_2 Capture = Estimated Annual Captured CO_2 (tpy) * Average \$/ton CO_2 captured from 3 studies

Table F-4 Capital and O&M Costs for CO_2 Transportation and Storage

Transportation and Storage Capital Costs				
Pipeline Costs[1]	**Formula for Estimate**[2]	**Units**	**June 2011 Dollars**	**June 2020 Dollars**
Pipeline Materials	70,350+2.01*L*(330.5*D2+686.7*D+26,960)	\$, D(in), L(mi)	\$2,068,926	
Pipeline Labor	371,850+2.01*L*(343.2*D2+2,074*D+170,013)	\$, D(in), L(mi)	\$6,268,854	
Pipeline Right of Way	51,200+1.28*L*(577*D+29,788)	\$, D(in), L(mi)	\$616,527	
Pipeline Miscellaneous	147,250+1.55*L*(8,417*D+7,234)	\$, D(in), L(mi)	\$2,177,378	
Surge Tank			\$1,244,744	
Pipeline Control System			\$111,907	
Total Pipeline Capital[4]			\$12,488,336	\$15,596,220
Storage Costs[3]	Number	Unit Cost, \$MM	**June 2019 Dollars**	**June 2020 Dollars**
Primary Injection Wells	5	\$5.0	\$25,000,000	
Backup Injection Wells	3	\$5.0	\$15,000,000	

Pressure Monitoring Wells	4	$4.0	$16,000,000	
Groundwater Monitoring Wells	5 Deep / 20 shallow	$0.20 / $0.025	$1,500,000	
Distribution Lines & Pumps	1 / 2	$10.0 / $1.0	$12,000,000	
Seismic and Microseismic Monitoring	Various	Various	$9,800,000	
Total Storage Capital[4]			$79,300,000	$81,282,500
	Total Capital + 15% Contingency			$111,410,530
Transportation and Storage O&M Costs				
Levelized Annual Transportation O&M[1,5]				$262,100
Levelized Annual Storage O&M[3,5]				$6,057,200

1. Transportation Capital and O&M values in 2011 dollars were developed with the FE/NETL CO_2 Transport Cost Model as detailed in: *Quality Guidelines for Energy System Studies: Carbon Dioxide Transport and Storage Costs in NETL Studies,* National Energy Technology laboratory, U.S. DOE, DOE/NETL-2019/2044 (August 2019)
2. Formulas for estimate do not give the same result as the CO_2 Transport Cost Model but are within 1%. They are for illustrative purposes.
3. Storage Capital and O&M estimates in 2019 dollars were based on previous site characterization completed through DOE's Southeastern Regional Carbon Sequestration Program (RCSP). The site is fully characterized and has been previously permitted with CO_2 injection and subsurface monitoring that was recently closed out from a pilot carbon capture unit at the site that captured CO_2 at a rate of 500 tpd.
4. "Total Pipeline Capital" in 2011 Dollars and "Total Storage Capital" in 2019 Dollars are changed to 2020 Dollars by escalating the capital expenses by 2.5% per year.
5. Transportation and Storage O&M costs were levelized by escalating costs in 2011 and 2019 dollars, respectively, by 2.5% annually throughout the relevant operating period to determine the NPV of each using a 7.7% discount factor. The levelized cost is the constant annual payment needed to equal the NPV assuming a 7.7% discount factor throughout the operating period. The operating period for transportation is 40 yrs while the operating period for storage includes 40 yrs of operation and 20 yrs of post-injection site monitoring to align with the CO_2 storage permitting (Class VI Underground Injection Control Permit).

Table F-5 Overall Cost of CCS

Levelized Annual Total Costs for CO_2 Capture[1]		$302,747,059
Total Capital Investment for CO_2 Transportation and Storage (TCI)[2]	$111,410,530	
Fixed Charge Rate (FCR)[3] (7.7% ATWACC, 2% property tax, AFUDC, 3 year construction period, 40 year operating period)	0.1132	
Amortized Annual Transportation and Storage Capital Costs (TCI*FCR)		$12,611,672
Levelized Annual Transportation O&M Costs[4]		$262,100
Levelized Annual CO_2 Storage O&M Costs[4]		$6,057,200
Total Annual CCS Costs		**$321,678,031**

1. From Table F-3
2. "Total Capital + 15% Contingency" from Table F-4
3. Grant, Ireson, and Leavenworth, *Principles of Engineering Economy, Seventh Edition*, Hoboken, NJ: John Wiley & Sons, 1982
4. From Table F-4