NORTH CAROLINA
PUBLIC STAFF
UTILITIES COMMISSION

May 29, 2024

Ms. A. Shonta Dunston, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

Re: Docket No. E-100, Sub 190 – Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)

Dear Ms. Dunston:

Yesterday, in the above-referenced docket, the Public Staff inadvertently filed an incorrectly redacted public version of the testimony and exhibit of Jeff Thomas, Engineer with the Energy Division of the Public Staff – North Carolina Utilities Commission. The incorrectly redacted version of the testimony has been removed from the docket system. Attached please find the **public corrected redaction version** of witness Thomas's testimony.

A copy of the public corrected redaction version was forwarded to all parties of record by electronic delivery yesterday evening. Confidential information is located on pages 30-32, 41, 47-48, 72, 74-75, 103-104, and 112 of the testimony.

The confidential version has been provided to those parties that have entered into a confidentiality agreement.

Sincerely,

Electronically submitted
/s/ Lucy E. Edmondson
Chief Counsel
lucy.edmondson@psncuc.nc.gov

/s/ Nadia L. Luhr
Staff Attorney
nadia.luhr@psncuc.nc.gov

Attachments

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-100, SUB 190

In the Matter of		
Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S. § 62-110.9 and § 62-110.1(c)	)))))	**TESTIMONY OF JEFF THOMAS PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION**

May 28, 2024

Q. Please state your name, business address, and current position.

A. My name is Jeff Thomas. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an engineer with the Energy Division of the Public Staff – North Carolina Utilities Commission.

Q. Briefly state your qualifications and experience.

A. A summary of my qualifications and experience is attached as Appendix A.

Q. What is the mission of the North Carolina Public Staff?

A. The Public Staff represents the concerns of the using and consuming public in all public utility matters that come before the North Carolina Utilities Commission. Pursuant to N.C. Gen. Stat. § 62-15(d), it is the Public Staff's duty and responsibility to review, investigate, and make appropriate recommendations to the Commission with respect to the following utility matters: (1) retail rates charged, service furnished, and complaints filed, regardless of retail customer class; (2) applications for certificates of public convenience and necessity; (3) transfers of franchises, mergers, consolidations, and combinations of public utilities; and (4) contracts of public utilities with affiliates or subsidiaries. The Public Staff is also responsible for appearing before State and federal courts and agencies in matters affecting public utility service.

Q. What is the purpose of your direct testimony in this proceeding?

A. The purpose of my direct testimony is to set forth the Public Staff's findings and recommendations resulting from our examination of the consolidated 2023 Carbon Plan and Integrated Resource Plan (CPIRP) filed by Duke Energy Progress, LLC (DEP), and Duke Energy Carolinas, LLC (DEC) (together, Duke or the Companies), in Docket No. E-100, Sub 190, on August 17, 2023, as well as the supporting direct testimony filed on September 1, 2023. My testimony also addresses the Supplemental Planning Analysis (SPA) filed on January 31, 2024, as a result of significant increases in Duke's electric load forecast.

Q. Briefly explain the scope of your investigation regarding the CPIRP.

A. My investigation largely covers the modeling inputs and techniques employed by the Companies in the development and presentation of their CPIRP. I performed modeling using EnCompass™ software by Yes Energy, the same modeling software used by the Companies, and in doing so collected input data, proposed modifications to

Duke's input data, and incorporated assumptions developed by other Public Staff witnesses.

Q. How is your testimony organized?

A. My testimony is organized as follows:

I. Introduction and Overview
II. Review of Duke's CPIRP
III. Investigation and Findings
IV. Public Staff Modeling Results
V. Public Staff Recommendations

Q. Are you providing any exhibits with your testimony?

A. Yes. I am including one exhibit, described below:

Thomas Exhibit 1. Final Report of the Southeast Regional Carbon Sequestration Partnership

I. INTRODUCTION AND OVERVIEW

Q. Please provide an overview of the testimony provided by Public Staff witnesses in this proceeding.

A. Public Staff witness Dustin Metz discusses his investigation into nuclear and natural gas generation resources included in the CPIRP, as well as transmission impacts and reliability. Witness Evan Lawrence discusses electric vehicle (EV) load forecasting, as well as onshore and offshore wind generation resources included in the CPIRP. Witness Blaise Michna discusses coal and natural gas resources and commodity price forecasts, as well as Duke's proposed conversion to 100% hydrogen in later model years. Witnesses Bob Hinton and Patrick Fahey (Load Forecast Panel) address the Companies' electric load forecast, including the large economic development load forecast that prompted the Companies to file the SPA. Witness David Williamson addresses the Companies' bill impact analyses and their assumptions regarding energy efficiency (EE) and demand side management (DSM) programs, as well as other load modifiers, tariffs, and customer programs. Witness Jordan Nader discusses the United States Environmental Protection Agency's (EPA) rulemaking pursuant to the Clean Air Act to address carbon dioxide (CO_2) emissions from coal and natural gas generation facilities. Finally, witness Michelle Boswell presents her recommendations regarding the Companies' request for relief and discusses potential federal funding opportunities under the Department of Energy's (DOE) Energy Infrastructure Reinvestment (EIR) program, which provides loan guarantees for certain projects that are aligned with decarbonizing the electricity system.

The Public Staff Index of Designated Issues, filed contemporaneously with the Public Staff's testimony, identifies the topics covered in the Public Staff's testimony, specifies which witness addresses each topic, and provides page references. In addition, Appendix B to each Public Staff witness' testimony identifies the topics covered by that witness and provides page references.

Public Staff's Investigation

Q. Please describe the Public Staff's investigation into the CPIRP.

A. The Public Staff's investigation of the CPIRP began immediately following the Commission's December 30, 2022 Order Adopting Initial Carbon Plan and Providing Direction for Future Planning (2022 Carbon Plan Order). The first stakeholder engagement session associated with the CPIRP was held in February 2023, with four additional meetings covering a wide array of topics held through June 2023. Numerous breakout groups met to discuss additional topics throughout this time period. The Public Staff participated in each of these meetings, which were used to develop the CPIRP.

Once the CPIRP was filed, the Public Staff engaged in detailed discovery in order to gather data and supporting information on the CPIRP, both sending its own discovery and reviewing the discovery sent by other parties. In the course of its investigation, the Public Staff met with several intervenors, and the Companies, multiple times to discuss various technical matters. Data used in the development of the CPIRP was compared against external sources and historical data, and a thorough investigation of the Companies' proposed electric load forecast was undertaken, with particular emphasis on large economic development customer loads.

Q. Did the Public Staff perform its own modeling?

A. Yes. Since 2022, the Public Staff has held a license for the EnCompass software used by Duke in the 2022 Carbon Plan and the current CPIRP. This license enables the Public Staff to perform its own modeling and sensitivity analyses, and to better understand how the model works and how data and assumptions are used in the model. My testimony will present the results of this modeling and explain the findings resulting from our sensitivity analyses. Witness Metz's testimony further explains how the modeling results have impacted the Public Staff's proposed near-term action plan (NTAP). The Public Staff's modeling input and output data files will be provided to parties who have entered into the appropriate confidentiality agreements upon request.

Key Findings and Recommendations

Q. What key recommendations are you making to the Commission?

A. The Public Staff's principal recommendation is that the Commission direct Duke to pursue the Public Staff's proposed NTAP, as presented in witness Metz's testimony. The Public Staff's proposed

NTAP is "least regrets" in the face of uncertainty and is likely to result in compliance with the 70% interim carbon reduction target[1] by 2034, rather than 2035 as requested by Duke in its recommended "P3 Fall Base" portfolio. The Public Staff's modeling shows that achieving compliance earlier than 2034 would require development and interconnection of unrealistic quantities of new resources, could threaten system reliability, and would significantly increase costs borne by ratepayers. The shift in compliance from Duke's proposed 2035 date to the Public Staff's proposed 2034 date results in several deviations from the Companies' NTAP and long-lead time resource development actions, summarized below.

Overall, the Public Staff's modeling suggests that the majority of Duke's proposed near-term actions are in line with a least-cost path towards carbon neutrality, although we do propose some modifications. As discussed in more detail in witness Metz's testimony, nearly all Public Staff model runs call for significant additions of solar, solar plus storage, standalone batteries, onshore and offshore wind, advanced nuclear, and natural gas resources.

[1] The interim compliance target is defined in N.C. Gen. Stat. § 110.9 as "a seventy percent (70%) reduction in emissions of carbon dioxide (CO_2) emitted in the State from electric generating facilities owned or operated by electric public utilities from 2005 levels by the year 2030…" The Commission has flexibility in implementing the interim compliance target, as outlined in N.C.G.S. § 110.9(4).

The Public Staff's proposed NTAP deviates from Duke's in the following ways: (1) it procures a higher proportion of solar capacity as solar plus storage; (2) it develops energy storage at a faster rate; (3) it accelerates work with offshore wind developers to closely evaluate project costs and, if appropriate, begin joint development actions;[2] and (4) it accelerates advanced nuclear development to meet or exceed modeled availability for new nuclear resources. Witness Michna's testimony addresses the Public Staff's concerns with Duke's plan to file five applications for Certificates of Public Convenience and Necessity (CPCNs) for new natural gas CC facilities prior to the issuance of the 2025 CPIRP final order, as more time is needed to assess the materialization rate of new large load customers and the impact of the new EPA emission standards.

As discussed later in my testimony, there is a critical period between approximately 2027 and 2033 during which there are limited resources available to add to the system (only solar, battery storage, and natural gas) and load is expected to grow rapidly from economic development projects. The Companies' Load Forecast Panel explains that these potential customers have very high load factors[3]

[2] *See* the Public Staff's April 17, 2024 Motion Requesting Issuance of Commission Order.

[3] Load factor is calculated as the ratio of average demand to peak demand. A load factor of 100% would correspond with load that consumes power at its peak load for all

and therefore require resources with high capacity factors. Coupled with the retirement of coal generation, the pace of these new load additions generally drives the selection of new natural gas fired combined cycle (CC) generation assets. However, as discussed in the testimony of witnesses Metz, Michna, and Nader, this selection of natural gas CCs carries with it significant risks, including that the expected load will not materialize and that the recently published EPA Clean Air Act rules[4] targeting the CO_2 emissions of new natural gas and existing coal generation plants will significantly increase costs by operationally limiting these facilities, either making them obsolete or requiring additional investment before the end of their useful life.

My testimony also provides recommendations for ways Duke might increase its interconnection capacity for new low-carbon generation assets and meet or exceed the interconnection limits set forth in the CPIRP. In addition, the Public Staff does not believe Duke is interpreting the DOE's EIR as broadly, or pursuing it as aggressively,

---

hours of the year. Many new, large load development customers have estimated load factors over 90%.

[4] *See* New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule, 89 Fed. Reg. 39,798 (May, 9, 2024). https://www.federalregister.gov/documents/2024/05/09/2024-09233/new-source-performance-standards-for-greenhouse-gas-emissions-from-new-modified-and-reconstructed

as it should, and witness Boswell and I therefore identify opportunities for maximizing available federal funding assistance.

As discussed by the Public Staff witnesses in their respective testimonies, there are significant challenges and risks facing Duke and its ratepayers as the Companies seek to meet future demand while decarbonizing. No source of generation is without risk in terms of cost, development timeline, and deployment, and the selection and pace of deployment of new resources in the CPIRP must contend with the costs and constraints that are included in the CPIRP's modeling, as well as with the potential costs and risks that are not.

The Public Staff's proposed NTAP places Duke on a path to achieving compliance with HB 951's carbon reduction targets (1) in a least-cost manner, (2) while maintaining grid reliability, and (3) in the fastest reasonable timeframe.

Q. If Duke implements the NTAP proposed by the Public Staff, is compliance with HB 951 guaranteed?

A. No. With the significant amount of uncertainty around the dates by which new resources will be available and the costs that will be incurred to procure them, it is not possible to guarantee compliance by a certain date. Much can happen even if the NTAP is perfectly implemented, such as an unseasonably hot summer or cold winter.

Compliance with S.L. 2021-165 (House Bill 951 or HB 951) is predicated on "reasonable steps,"[5] and the Public Staff does not expect Duke to forego the use of carbon-emitting resources during a system emergency for fear of violating CO_2 constraints.

However, if our recommended pathway is followed, and Duke aggressively pursues the federal funding and cost-effective opportunities enumerated in the Public Staff's collective testimony, the costs of compliance can be minimized. The least-cost pathway is not only statutorily required, it is critically important to ratepayers throughout this state, who have made their voices heard through thousands of statements of position and testimony before this Commission over the years, and who have already seen their electricity bills increase significantly in recent years. I have read and listened to hundreds of these statements in my time with the Public Staff, as many have spoken of the financial burden of their electricity bill and of their concern for their communities and their futures. The Public Staff's review, modeling, and testimony therefore place an emphasis on the appropriate balance between emission reductions, cost, reliability, and execution risks.

[5] Section 1 of HB 951 states that "[t]he Utilities Commission shall take all reasonable steps to achieve a seventy percent (70%) reduction in emissions of carbon dioxide (CO_2) emitted in the State from electric generating facilities owned or operated by electric public utilities from 2005 levels by the year 2030 and carbon neutrality by the year 2050."

II. REVIEW OF DUKE'S CPIRP

Q. Please briefly summarize this section of your testimony.

A. This section of my testimony provides an overview of Duke's modeling process and the tools that underlie Duke's CPIRP proposal. I will describe Duke's proposed reserve margin and the Company's process for evaluating the contribution of variable resources towards that reserve margin. Finally, I will address Duke's inclusion of Bad Creek II in the CPIRP and provide an overview of Duke's portfolio costs.

Q. Please provide a general overview of Duke's CPIRP.

A. Duke's CPIRP, filed August 17, 2023, included numerous modeling scenarios, including three Pathways with interim compliance dates of 2030, 2033, and 2035, respectively; variants addressing resource availability and natural gas supply; sensitivities with high and low resource costs, fuel costs, EE and DSM, and electric load; and supplemental portfolios addressing the proposed (now finalized) EPA Clean Air Act rule. Duke requested Commission approval of its recommended portfolio, Portfolio 3 Base (P3 Base), which meets the interim compliance target in 2035.

The Companies provided an analysis of each Pathway, sensitivity, and variant, in addition to the corresponding EnCompass input and output files. The Companies also modeled each scenario in the

Strategic Energy Risk Valuation Model (SERVM), which has been used for several years to validate portfolio reliability and to estimate the target reserve margin and the Effective Load Carrying Capability (ELCC) of renewable resources. The Companies also calculated the estimated Present Value of Revenue Requirements (PVRR) and the estimated North Carolina retail bill impacts for each scenario.

In its January 2024 SPA, the Companies updated their load forecast, adding significant new load driven by economic development projects in the Carolinas. In addition, the Companies made several changes to their modeling assumptions, as outlined in Table SPA 2-1. These updates included modifications to resource costs and interest rates based on market data; updates to natural gas supply assumptions, increasing the number of CCs the model was permitted to select from three to six; and modifications to resource availability for solar, battery storage, offshore wind, and advanced nuclear.

Q. Please describe the modeling process that underlies Duke's CPIRP.

A. The CPIRP and SPA are both based on energy system modeling performed in EnCompass. However, even before EnCompass was used, the Companies had to develop input data. Inputs come from the Companies' operational experience and a variety of external sources. Some inputs, such as the target reserve margin and ELCC of renewable energy and battery storage, were derived from the use of the SERVM software that Duke has licensed from Astrapé Consulting.[6] These inputs were reviewed, finalized, and then put into the appropriate format for EnCompass.

EnCompass seamlessly integrates two types of models used in the development and assessment of each scenario. The first model is referred to as a capacity expansion model. This model has low temporal granularity, modeling representative days of the week (weekday, weekend) and optimizing over representative time periods (six time periods per day). The capacity expansion model is used to determine the optimal retirement date of existing coal units, and also economically select new resources to meet load and comply with model constraints. Due to the number of variables for which the model must solve, it is not possible for a capacity expansion model to simulate each hour of the year.

The results of the capacity expansion model are then fed directly into a production cost model, which performs a more detailed analysis of system operations without needing to economically select new resources. The production cost model solves for each hour of the

[6] SERVM is a reliability model that performs hundreds of simulations using random draws of generator outages, renewable output profiles, weather, and load. These simulations are analyzed to estimate system reliability.

year over the CPIRP modeling period (2024 through 2050), dispatching existing and economically selected resources to meet demand on an hourly basis.

Q. Does EnCompass have the ability to validate system reliability?

A. No. EnCompass is referred to as a deterministic model – the results assume that the input hourly load forecast and renewable generator output profiles are fixed and known, and only one forecast and one profile is used. Since it is impossible to know what the actual demand and solar output will be in the future, the model result represents a single possible outcome.

Q. How did the Companies test their proposed portfolios to ensure that they will "maintain or improve upon the adequacy and reliability of the existing grid"?

A. To evaluate whether the selected portfolio can maintain system reliability, the SERVM model is used. SERVM is a stochastic model that incorporates uncertainty by creating dozens of possible load shapes and output profiles based on historical weather data. SERVM then analyzes the system over a single year hundreds of times, randomly drawing different load shapes, output profiles, and generator outages for each run. The results are analyzed to determine if the system can maintain a Loss of Load Expectation (LOLE) of one event in ten years, accounting for a combined DEC and DEP system. In the event that a selected portfolio does not meet the LOLE target, Duke manually adds combustion turbines (CTs) until the target is met.

Compliance with 2022 Carbon Plan Order and Changes from 2022 Carbon Plan

Q. Is the CPIRP largely similar in structure and process to the 2022 Carbon Plan?

A. Yes. While many of the input values and assumptions have changed since the 2022 Carbon Plan was filed, the basic overarching process was similar. Along with the CPIRP, Duke also filed a Resource Adequacy Study supporting its proposed 22% target winter reserve margin and two ELCC studies supporting its proposed treatment of wind and solar resources.

Q. Are there any matters in which the CPIRP or the SPA deviate from the 2022 Carbon Plan Order?

A. Yes. My investigation of the CPIRP and SPA has revealed at least three significant deviations from the 2022 Carbon Plan Order. First, the Companies utilized a seven-year optimization period for their capacity expansion modeling, while the Commission directed Duke to make all practicable efforts to maximize its optimization period, recommending an optimization period of 15 years or greater.[7] Duke stated that this deviation was due to excessively long run times when using a longer optimization period.[8]

The second deviation relates to the Commission's directive that it is appropriate to assume for modeling purposes that all new CO_2 emitting resources will be located in North Carolina and therefore subject to the statutory carbon limit.[9] In the SPA, however, Duke assumed that one CC would be located in South Carolina and not subject to the carbon emission limits.[10]

Finally, the Commission directed Duke to incorporate the impact of the Inflation Reduction Act (IRA), the Infrastructure Investment and Jobs Act (IIJA), and other future legislation into its CPIRP.[11] While the Companies did incorporate the impacts of the IRA's tax credits available to clean energy resources, including consideration of the energy community bonus adder, the Companies did not incorporate the IIJA or other aspects of the IRA. Some of the individual grant applications the Companies have submitted under the IIJA are not likely to impact resource selection in the CPIRP, as many of these

---

[7] *See* 2022 Carbon Plan Order, at 49-50.

[8] *See* Direct Testimony of witnesses Snider, Quinto, Beatty, and Passty, at 27-29.

[9] *See* 2022 Carbon Plan Order, at 45.

[10] *See* Supplemental Planning Analysis, at 26.

[11] *See* 2022 Carbon Plan Order, at 48.

grants would be for existing hydroelectric uprates or for existing nuclear plants. However, the Companies did not incorporate a major component of the IRA, specifically, the EIR loan program administered by the DOE's LPO. As discussed in more detail later in my testimony, the Public Staff has concerns regarding Duke's failure to model the EIR program, which is authorized to provide up to $250 billion in guaranteed federal government loans to eligible projects, including projects that replace fossil fuel infrastructure.[12]

Q. Does the Public Staff agree with these deviations?

A. With respect to the optimization period, the Public Staff understands the Companies' concerns regarding a longer optimization period. In its own modeling, the Public Staff attempted to use a 15-year optimization period for its capacity expansion plans. Unfortunately, this led to significantly extended model run times, with capacity expansion models taking between six and 24 hours to complete; in some cases, 15-year model runs failed entirely. In addition, while longer optimization periods did show slight variation in resource selection (e.g., slightly accelerated battery deployments), they generally did not impact the selection of offshore wind or CCs. As such, the Public Staff agrees with Duke's rationale for using a seven-

[12] *See* the Title 17 Clean Energy Financing Program Guidance (Title 17 Program Guidance), available at https://www.energy.gov/lpo/articles/program-guidance-title-17-clean-energy-program.

year optimization period and has likewise used a seven-year optimization period in its own modeling.

The Public Staff does not agree with Duke's assumption that one CC unit will be built in South Carolina and be exempt from the carbon emission constraint. As discussed in more detail in witness Metz's testimony, it is certainly possible that Duke will build a CC in South Carolina, but it is unclear when such a unit might be proposed or whether it would be approved by the South Carolina Public Service Commission (SCPSC). The Public Staff has therefore removed the South Carolina CC from its modeling portfolios.

Finally, the Public Staff is concerned that Duke has not incorporated the EIR into its modeling. As discussed later in my testimony and in the testimony of witness Boswell, the EIR represents a significant opportunity for cost savings for ratepayers tied to the deployment of new clean energy resources that can help drive down the projected costs of the CPIRP. The Public Staff has incorporated EIR financing assumptions for eligible resources into its model to illustrate the baseline portfolio resource changes and associated savings impact that the loans can provide.

Interim Target and Carbon Constraint Modeling

Q. Please describe the role of the interim target and how it is modeled.

A. The year chosen to meet the interim compliance target is a fundamental input to the CPIRP and can be considered as influential to resource selection as the electric load forecast. The carbon constraint not only drives resource selection, but also drives resource dispatch – for example, an earlier interim compliance year might result in a decline in coal generation with a corresponding increase in natural gas generation when the CO_2 constraint is binding, even if it is uneconomic. While the model can violate the CO_2 constraint, it imposes a $10,000 per ton penalty for such a violation, even though no such penalty is required by HB 951. In other words, the penalty for violating the CO_2 constraint is a function of the model alone.[13] Duke also assumes that 2050 carbon neutrality will be met in part through the use of carbon offsets, up to 5% of the authorized goal, as permitted by N.C.G.S. § 110.9.

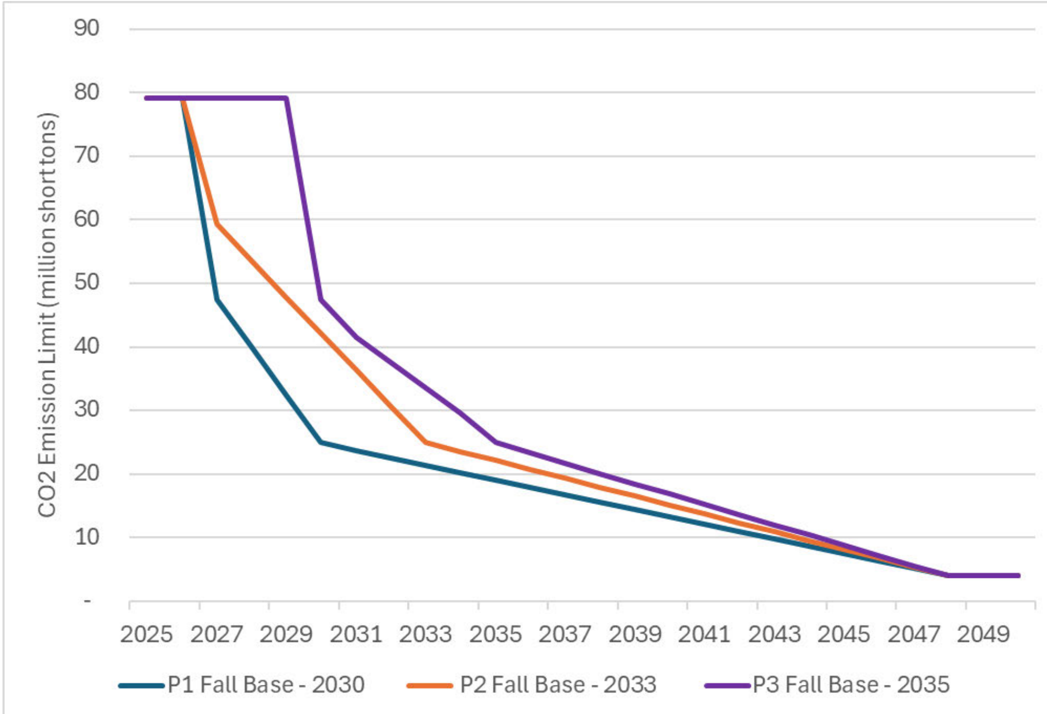
[13] The constraint is modeled in this way to allow for flexibility if the limit imposed is impossible to meet. If a penalty is not imposed, the optimization algorithm could simply ignore the carbon cap. In order to ensure the model prioritizes reliability over meeting carbon emission targets, the penalty for shedding load is significantly greater than the penalty for violating the carbon constraint. The Public Staff used the same penalty as was used in Duke's modeling.

The carbon constraints used by the model are shown in Figure 1 below. Notably, Duke models the interim target at approximately 24.9 million short tons. While this target is technically higher than the interim target of 22.8 million short tons approved in the 2022 Carbon Plan Order,[14] the difference is due to the Companies' fossil fuel-fired units located in South Carolina.[15] The modified CO_2 limit was designed to be imposed as a system-wide limit that would result in a system that meets North Carolina requirements without relying on uneconomic dispatch of South Carolina generators.

[14] *See* 2022 Carbon Plan Order, Ordering Paragraph 3, at 131.

[15] This includes the Lee, Mill Creek, and Darlington CTs (together, approximately 1,111 MW of winter capacity); the W.S. Lee CC (809 MW); and the Clemson Combined Heat and Power generator (15.5 MW).

Figure 1: Carbon Constraints used in the CPIRP



Q. Please explain what you mean by "uneconomic dispatch of South Carolina generators."

A. While Duke could have used the 22.8 million short ton emission cap as its interim limit and excluded the South Carolina emissions from the limit, doing so would have resulted in uneven dispatch as the model would have utilized the South Carolina fossil fuel units over North Carolina units to comply with the limit, potentially deviating from least-cost economic dispatch and instead relying on environmental dispatch.[16] As shown in Table 1 below, the approach utilized by Duke results in North Carolina meeting the interim compliance target of 22.8 million short tons in 2035. The Public Staff views this modeling approach as reasonable.

Table 1: Summary of CO2 Emissions in P3 Fall Base Interim Compliance Year

Emission Source P3 Fall Base - 2035	CO_2 Emissions (million short tons)
Total system emissions	28.1
New South Carolina CC	3.1
Existing South Carolina Units	2.2
Total North Carolina Emissions	**22.8**

Q. What interim target year did the Companies utilize?

A. The Companies' recommended portfolio, P3 Fall Base, targets an interim compliance year of 2035. In addition, the Companies submitted portfolios that target interim compliance in 2030 (P1 Fall Supplemental) and in 2033 (P2 Fall Supplemental). Significant changes were made to the base interconnection limits for each of these portfolios in order to comply with the target, primarily by increasing the amount of solar and batteries that could be added while accelerating offshore and onshore wind deployment.

[16] Environmental dispatch describes an action where the utility prioritizes environmental constraints in the dispatch of its generation fleet, such as dispatching natural gas before coal even when coal is less expensive, in order to reduce CO_2 emissions. This is in contrast to economic dispatch, where the utility dispatches its fleet based on least cost operations.

Q. How will the Companies evaluate compliance with the interim target?

A. As described in Appendix A of the 2022 Carbon Plan, the Companies intend to utilize emissions data submitted to the EPA through the Clean Air Markets Division's (CAMD) Power Sector Emissions Data software and reported through eGRID.[17] While publication of eGRID annual data is typically delayed, with data through 2022 released in January 2024, the Companies state that they will be able to provide emissions data validated by the EPA in the first quarter following the year in question (e.g., validated emissions data for 2030 would be available in the first quarter of 2031). The Public Staff finds this acceptable.

Resource Adequacy Study

Q. What is a reserve margin?

A. A reserve margin is defined as the amount of generation that is available on the system in excess of peak load. During day-to-day system operations, the reserve margin is a mathematical calculation based on peak load and available generation. During resource planning, the reserve margin is used as an input to the model that forces the model to build more than is needed simply to meet the

[17] *Available at* https://www.epa.gov/egrid/download-data.

forecasted peak load. This margin is an important aspect of resource planning because the load forecasts used are weather normalized and are not based on the very high loads associated with extreme weather. Resource planning also assumes typical outage characteristics and representative output profiles for solar and wind.

In practice, weather, electric load, generator outages, and renewable output can vary greatly from projections used in resource planning. The reserve margin is therefore used to ensure that even if weather and load are more extreme than projected, more outages occur than expected, or renewable generation is lower than anticipated, there will still be sufficient generation to meet demand in most instances.

Q. What are the risks when selecting a target reserve margin?

A. A target reserve margin that is higher than necessary will provide a more reliable system and reduce the likelihood of future load shed events; it results, however, in higher costs due to the acquisition and interconnection of excessive generation. A target reserve margin that is too low may reduce system costs by foregoing some generation plants, but it increases the likelihood of load shed events. Determining the appropriate reserve margin is therefore a complex evaluation of tradeoffs between cost and desired reliability.

Q. How does Duke determine its target reserve margin?

A. Duke estimates the appropriate target reserve margin in its 2023 Resource Adequacy Study (2023 RA Study), included as Attachment I to the CPIRP. This study is substantially similar in structure to the resource adequacy studies filed with the Companies' integrated resource plans since 2012. Conducted using SERVM,[18] the 2023 RA Study evaluates system reliability in 2027 by completing hundreds of model runs, all of which draw upon different weather years, load profiles, solar and wind output profiles, and outage occurrences. These runs are then analyzed to determine the LOLE that is achieved; if the 0.1 LOLE standard is not met, the portfolio is "calibrated" by adding capacity resources (CTs) until the standard is met. The resulting reserve margin, inclusive of the added resources, becomes the target reserve margin. The target reserve margin is then used as an input to the CPIRP, which requires the model to maintain sufficient reserves to meet that reserve margin.

Q. What is Duke's target reserve margin for the CPIRP?

A. In this proceeding, Duke proposes a winter target reserve margin of 22%, which is a significant increase from the 17% used in the 2022 Carbon Plan. This target reserve margin is based on simulations that treat DEC and DEP as a combined system with access to capacity

---

[18] This is the same model that Duke uses to evaluate portfolio reliability and to determine the contributions made towards the reserve margin by solar, storage, and wind resources.

from neighboring balancing authorities (BAs) such as PJM Interconnection (PJM) and the Tennessee Valley Authority (TVA).

Q. What is driving the increase to Duke's target reserve margin?

A. The 5% increase in the target reserve margin is being driven by three main factors: (1) a reduction in assumptions of available neighbor assistance; (2) assumptions regarding long-term forecast error; and (3) increased generator outages, particularly during cold weather events.[19]

Q. Please explain Duke's assumption that neighbor assistance would be reduced.

A. The reduction in neighbor assistance is driven by two factors: (1) a shift from summer to winter risk;[20] and (2) coal retirements and buildouts of solar, wind, and storage resources in neighboring BAs.[21]

[19] *See* 2023 RA Study, at 52.

[20] *See* the North American Reliability Council (NERC) 2023 Summer Assessment, which found that PJM, SERC-East, and SERC-Southeast were at a low risk of capacity shortfalls in the summer. Compare this to NERC's 2023/2024 Winter Assessment, which found that PJM, SERC-East, and SERC-Central were at an elevated risk of capacity shortfalls in above-normal winter conditions. Duke is a member of SERC-East.

2023 Summer Assessment, at 6: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf

2023/2024 Winter Assessment, at 5: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf

[21] For example, Dominion Energy, which neighbors Duke to the northeast, is subject to the Virginia Clean Economy Act of 2020, which requires Dominion to deliver electricity from 100% renewable sources by 2045. This is driving a buildout of solar, wind, and battery storage.

As neighboring BAs build out solar and wind, resource diversity across the region decreases, which can reduce Duke's ability to rely on those BAs as it likewise builds out solar and wind. On a cool spring afternoon, Duke may not be able to sell its excess solar energy into PJM if PJM also has excess solar energy; and on a cold winter morning, neighboring BAs that also rely heavily on solar may compete with Duke as each BA attempts to secure external capacity assistance.[22] The reduction in the assumption of neighbor assistance accounts for an estimated 1.75% of the overall 5% increase.

Q. What changes did Duke make to its long-term forecast error assumptions?

A. When a load profile is randomly selected during the 2023 RA Study, a long-term forecast error multiplier is also selected to account for uncertainty in load forecasts. The probability distribution is based on Moody's Analytics economic scenarios that estimate the probability that economic forecasts (which are correlated with load forecasts) may be incorrect. This multiplier will either increase or decrease the selected load profile, corresponding to Duke either under or over forecasting load, respectively. In the 2023 RA Study, Duke shifted

[22] For example, during Winter Storm Elliot, Duke had 900 MW of "firm" capacity purchases curtailed by PJM, exacerbating the system emergency in Duke's territories. *See* the Commission's December 22, 2023 Order Making Findings And Directing Actions Related To Impact Of Winter Storm Elliott, at 8 and 10.

the long-term forecast error probability distribution towards potential under-forecasting errors. This modification is responsible for an estimated 0.75% of the overall 5% increase.

Q. Why is updated generator outage data driving a higher reserve margin?

A. While thermal resources are assumed to be capable of supplying 100% of their nameplate capacity to meet the reserve margin, the calculation of the target reserve margin takes into account unit outages. All else equal, a higher outage rate for thermal resources will result in more outages, increasing the likelihood of load shed events and driving a higher target reserve margin. The 2023 RA Study updated the Companies' generator outage data to incorporate more recent generator outages from 2018 through 2022, inclusive of Winter Storm Elliot (the 2020 RA Study used in the 2022 Carbon Plan was based on generator outage data from 2014 through 2019).

[BEGIN CONFIDENTIAL] [redacted]

[redacted] **[END CONFIDENTIAL]** However, it should be noted that the outage rates used in the 2023 RA Study do not reflect any of the cold weather improvements the Companies are implementing in response to recent winter storms, including Winter Storm Elliot.[23]

Figure 2: Actual and modeled unit outages at various temperatures, 2018 to 2022

[BEGIN CONFIDENTIAL]

[redacted]

[23] *See* the Companies' presentation during the September 26, 2023 Technical Conference on Winter Storm Elliot in Docket No. M-100, Sub 163. The presentation was filed in the docket on December 21, 2023.

[redacted]

[END CONFIDENTIAL]

The update to generator outage data, along with additional quantified winter capacity risk related to the increased risk of generator outages and very high loads in extreme winter weather, is responsible for an estimated 2.5% of the overall 5% increase. The Public Staff has addressed this declining reliability in other proceedings,[24] and witness Metz addresses it in his CPIRP testimony.

Q. How did Duke implement the target reserve margin in the CPIRP?

A. In its initial filing, Duke implemented the 22% reserve margin target beginning in 2029, allowing the system to maintain a 17% reserve margin until then. In the SPA, Duke delayed the 22% reserve margin until 2031.

[24] *See* Direct Testimony of Dustin Metz, filed on July 19, 2023, in Docket No. E-2, Sub 1300, at 63; and the Direct Testimony of Dustin Metz, filed on March 27, 2023, in Docket No. E-7, Sub 1276, at 22.

Q. What is the overall impact of the 22% reserve margin?

A. While it is difficult to quantify the cost of the increase in the reserve margin, the amount of incremental firm capacity that must be available is easily determined based upon the peak load forecast. By 2035, a 22% reserve margin requires an additional 1,115 MW of firm capacity in DEC and 806 MW of firm capacity in DEP, relative to a 17% reserve margin.[25] As described later in my testimony, firm capacity refers to the winter rating of dispatchable thermal resources and the capacity value of renewable and energy storage resources.

Q. Did the Public Staff identify any issues with the 22% reserve margin?

A. No. While many assumptions are made in the 2023 RA Study, the overall trend of higher reserve margins has been observed throughout the southeast. TVA is using a 25% winter reserve margin;[26] Georgia Power is recommending a 26% winter reserve margin;[27] Dominion Energy South Carolina is targeting a 20.1%

---

[25] Based upon DEC's forecasted net system peak of 22.3 GW in 2035 (*see* Table SPA 2-6) and DEP's forecasted net system peak of 16.1 GW (*see* Table SPA 2-7).

[26] *See* TVA's 2019 IRP, at 4-7, available at https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/default-document-library/site-content/environment/environmental-stewardship/irp/2019-documents/tva-2019-integrated-resource-plan-volume-i-final-resource-plan.pdf?sfvrsn=44251e0a_4

[27] *See* Georgia Power's 2023 IRP, at 5, available at https://www.georgiapower.com/content/dam/georgia-power/pdfs/company-pdfs/2023-irp-update-main-document.pdf

winter reserve margin;[28] and Santee Cooper is utilizing a 17% winter reserve margin.[29] It is not unreasonable to assume that a higher reserve margin is necessary given the changes to system dynamics that have occurred since the 2020 RA Study was completed. The Public Staff is concerned that declining generator reliability across the Companies' existing fleets is driving the need for a higher reserve margin, particularly given that recent winter-weather improvements are not reflected in the data. However, even if the impact of these updated outages were removed, the Companies would likely still increase their reserve margins to over 20%.

Q. What reserve margins did P3 Fall Base achieve?

A. The modeled winter reserve margin for P3 Fall Base is shown in Figure 3 below.[30] Because the reserve margin constraint is just one of many constraints that influence resource selections, it is evident that the winter reserve margin is higher than needed for most of the planning horizon. However, there are several key periods where the reserve margin drives the need for new resources: in approximately

---

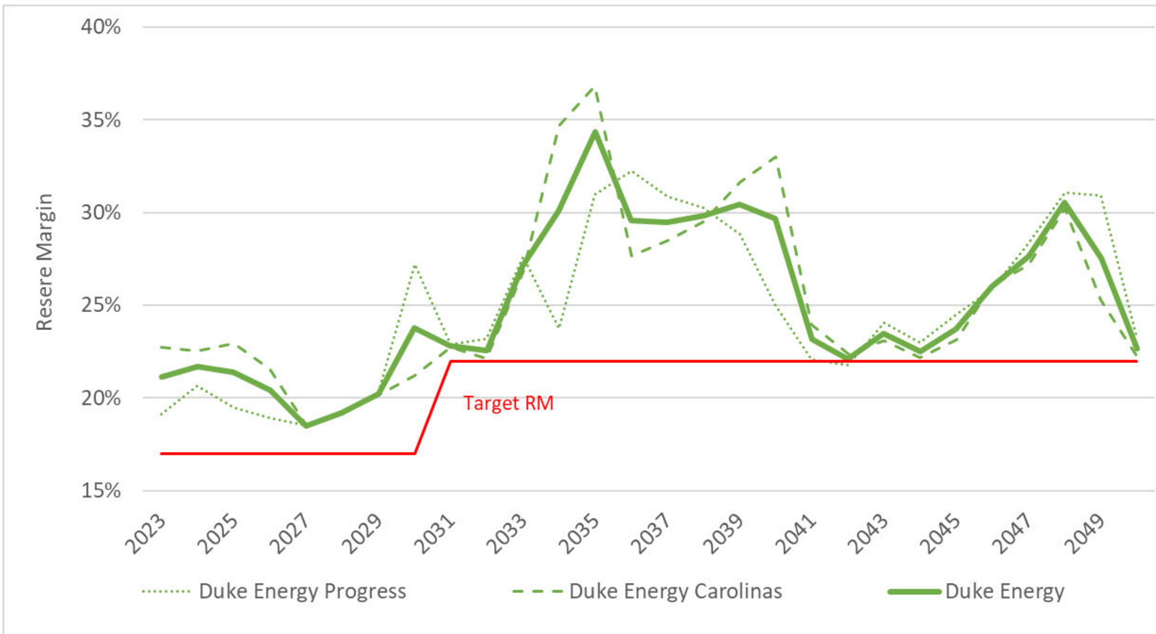
[28] *See* Dominion Energy South Carolina's 2023 IRP, at 51, available at https://www.dominionenergy.com/-/media/pdfs/global/company/desc-2023-integrated-resource-plan.pdf

[29] *See* Santee Cooper's 2023 IRP, at 73, available at https://www.dominionenergy.com/-/media/pdfs/global/company/desc-2023-integrated-resource-plan.pdf

[30] The summer reserve margin is generally non-binding on the model, due to the significantly higher capacity value of solar in the summer than the winter.

2032 and again in the early 2040s. The need for additional capacity in the early 2030s is due to the factors I discussed previously that make this early period so critical – rapid load growth, large-scale coal retirements, and limited availability of resources.

Figure 3: P3 Fall Base Winter Reserve Margin



Between 2040 and 2044, the model assumes approximately 5.9 GW of existing capacity, primarily CTs, will retire as they reach the end of their operable lives. This decline in available capacity may contribute to the sustained growth of advanced nuclear during this time period, with P3 Fall Base adding 2.1 GW of small modular reactors (SMRs) and 1.3 GW of advanced nuclear capacity between 2040 and 2044.

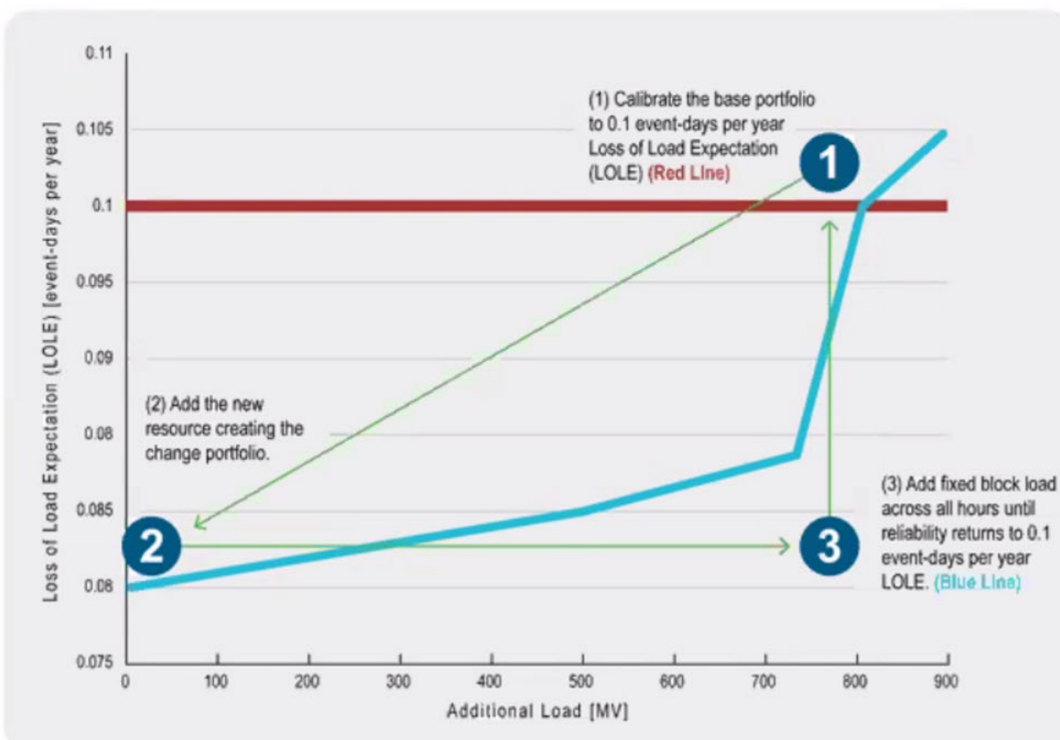
Solar, Battery, and Wind Effective Load Carrying Capability Studies

Q. You previously discussed "firm capacity" as it relates to the target reserve margin. How is firm capacity determined for renewable resources?

A. Unlike dispatchable resources whose generation output generally mirrors their nameplate rating at any time (barring an outage), non-dispatchable or energy-limited resources cannot count their full nameplate capacity towards the reserve margin target because they are dependent upon weather conditions or solar irradiance, or may be otherwise energy-limited (e.g., a 100 MW / four-hour battery can only output its maximum capacity for up to four hours). Therefore, these resources instead use a capacity value to determine the proportion of the resource's capacity that can be relied upon to meet the reserve margin. For example, the capacity value of solar during the winter morning peak is very low but may be much higher for the summer peak. The capacity value of solar, wind, and energy storage is determined by an ELCC study, which Duke has submitted as Attachment II and III to its CPIRP.

The ELCC study also utilizes SERVM to estimate the capacity value through a three-step process, as shown in Figure 4 below. First, the base portfolio is calibrated to a 0.1 LOLE by adding CTs, in a similar manner as the 2023 RA Study. Next, a block of the resource being studied is added to the resource mix (e.g., 200 MW of solar), reducing the LOLE to below 0.1. Finally, load is added in each hour until the LOLE returns to 0.1. The capacity value of the studied resource is the ratio of the amount of load added to the amount of resource added. In this example, if a 50 MW increase to load returns the model to 0.1 LOLE, the capacity value of solar would be 25% (50 MW load increase / 200 MW of added solar).

Figure 4: ELCC Process



Q. Are capacity values for non-dispatchable or energy-limited resources constant?

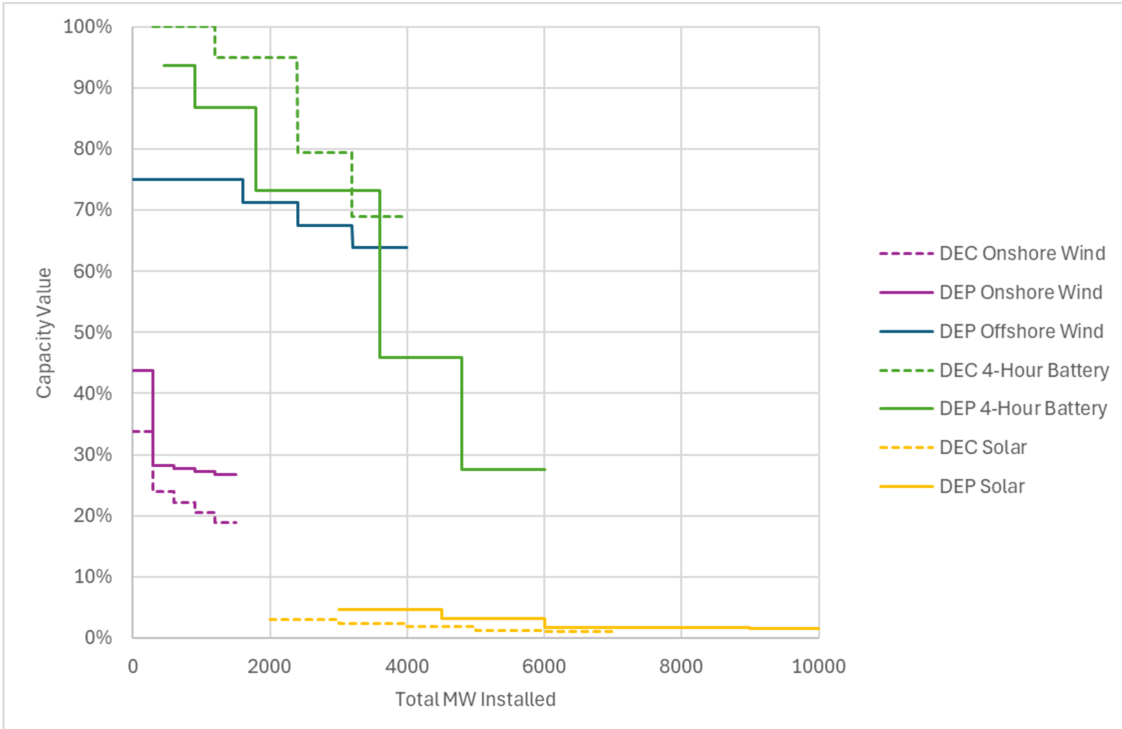
A. No. The ELCC studies employed by the Companies create an ELCC curve, which generally shows that as more of a particular resource is added, the capacity value of that resource decreases.[31] The marginal winter ELCC curves for wind, solar, and four-hour batteries are found in Figure 5 below.[32]

---

[31] For example, as more solar is added to the grid, it will reduce the load during solar hours and may eventually shift the peak load net of solar into the evening hours, where solar is not as productive. This shift in peak will decrease the capacity value of incremental solar resources.

[32] Solar and battery storage ELCC values were derived from Attachment II, Tables 5 and 6. Wind ELCC values were derived from Attachment III, Table 3.

Figure 5: Marginal Winter ELCC Curves for Wind, Four-Hour Batteries, and Solar



These declining ELCC curves are modeled in EnCompass, which assigns an incremental capacity value to new resources that depends upon the cumulative amount of the resource that has been added.

Q. Does the Public Staff find the Companies' determination of capacity values to be reasonable?

A. Yes. Reliability-based estimates of capacity value through an ELCC study are widely accepted in the industry and provide a more precise estimate than approximation methods used in the past. While I discovered some discrepancies related to how offshore wind capacity values were incorporated into EnCompass, which I address later in my testimony, overall, the determination of capacity values appears reasonable.

Bad Creek II

Q. Please address the Companies' inclusion of Bad Creek II in the CPIRP.

A. Bad Creek II is a planned expansion of the Bad Creek pumped storage facility located in DEC's South Carolina service territory that would add a second powerhouse, doubling the generating capacity while halving the duration.[33] Bad Creek was primarily designed to store large quantities of energy over the weekend and discharge it during the week, but due to changes in Duke's system since it was first constructed in 1977, it now operates on a daily basis to store solar energy and discharge it when it is needed. Duke's plans to increase the capacity of Bad Creek are under review as part of ongoing relicensing efforts at the Federal Energy Regulatory Commission (FERC). The Companies have stated that they are currently working to contract with consultants familiar with pumped

[33] A second powerhouse will require its own set of penstocks to move water between the upper and lower reservoirs. When this is added, the maximum discharging and charging capacity of the entire Bad Creek facility will be doubled because twice as much water can flow through the turbine generators. However, water in the upper reservoir can now be drained at twice the previous rate, which would halve the amount of time the powerhouses could discharge the stored energy.

storage and have engaged an engineering, procurement, and construction contractor to review bid packages and design work.

The Companies, through their Petition for Relief, are requesting that the Commission make a determination that engaging in initial development activities for pumped storage hydro "is a reasonable and prudent step in executing the updated Carbon Plan and necessary to enable execution of . . . Bad Creek II."[34] The Companies further request Commission approval of approximately $165 million in costs for development activities related to Bad Creek II from 2023 through 2026.[35] Duke's estimated capital cost for Bad Creek II is approximately **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in 2034.

Q. How did the Companies model Bad Creek II?

A. As in the 2022 Carbon Plan, the Companies forced Bad Creek II into most model runs in 2034, rather than allowing it to be economically selected. Generally, this decision is made because a capacity expansion model tends to undervalue longer-duration energy storage. In the CPIRP, the Companies validated the inclusion of Bad Creek II in two ways.

---

[34] Amended Petition for Relief, at (2)(d)(i).

[35] Amended Petition for Relief, at (2)(d)(iii) (requesting that the Commission determine that Duke is "authorized to incur project development costs up to $165 million for the development of pumped storage hydro from 2023 through 2026").

First, the Companies compared portfolios with and without forcing in Bad Creek II, providing PVRR analyses showing that without Bad Creek II, total portfolio costs were higher. In P3 Fall Base, the PVRR through 2050 was approximately $1 billion, or 0.7%, higher when Bad Creek II was excluded. This finding generally supports the inclusion of Bad Creek II, although the PVRR reduction is relatively low.

The second method was only performed in the initial filing, where Duke allowed Bad Creek II to be economically selected in its P3 Base portfolio, rather than forcing it in. The model did economically select this resource in 2036, making it part of the least-cost path to compliance through the P3 Base portfolio. This step was not repeated in the SPA. Duke explained that it was still prudent to pursue Bad Creek II by 2034, as it allows for project delays, can accommodate future load growth, and serves as a hedge against future constraints in the battery storage pipeline.

Q. Does the Public Staff support the inclusion of Bad Creek II in the CPIRP and the Companies' engagement in initial project development activities?

A. Yes. The Public Staff recognizes the value of long-duration energy storage as the system increasingly relies on carbon-free intermittent resources to meet demand, and generally has no issues with the planned in-service date of 2034. The Public Staff further believes that it is reasonable for the Companies to engage in initial development activities for Bad Creek II. The Companies' planned expenses of $165 million to begin development of Bad Creek II are also reasonable and well supported. I have provided this recommendation to witness Boswell, whose testimony addresses the Companies' request to incur project development costs. I also recommend that if the estimated costs of Bad Creek II increase by 15% or more prior to the next CPIRP, that Duke notify the Commission and submit a revised capacity expansion plan using updated cost information.

Portfolio Costs

Q. How did the Companies calculate the estimated cost of each portfolio?

A. Total portfolio cost is presented in terms of both PVRR and retail customer bill impacts. The PVRR is the present value of the revenue requirements for constructing and operating each portfolio, inclusive of rate base increases, return on equity, and operating costs. As this is a present value calculation, costs that are further out are more highly discounted and have a smaller impact on the PVRR. However, this metric is one that generally indicates the total cost to ratepayers of each plan.

The bill impact analysis converts the annual revenue requirement figures into an estimated bill impact for retail customers, which is then translated into monthly bill increases over a set period of time. The Companies' bill impact analysis is discussed in more detail in witness Williamson's testimony.

Q. Can you speak to the 20% capital cost adder used by the Companies in certain portfolios?

A. Yes. For the 2030 interim compliance portfolios (P1 Base in the initial filing and P1 Fall Supplemental in the SPA), the Companies ran the models with the same capital costs as all other models. However, to account for "cost risk premium" associated with such high levels of resource additions, the Companies applied a 20% capital cost increase in the PVRR calculation. Because this cost risk premium was added only during PVRR calculations, it did not influence the economic selection of resources.

Q. Did this cost risk premium apply only to renewable resources?

A. No. This adder was applied to all resources in the PVRR analysis.

Q. Do you have any issues with the cost risk premium?

A. No, not in the way it was applied. If the premium were only applied to renewable resources, or if it were used to influence the selection of resources in the model, it may have been inappropriate. However, procuring the significant quantity of resources needed to implement

P1 Fall Supplemental will almost certainly cause costs to increase. These higher costs could include higher interconnection costs as this work is expedited, or higher capital costs as the Companies compete on the open market for critical components.

For example, consider the annual solar and solar plus storage competitive procurements that the Companies use to obtain resources identified in the CPIRP. In the 2023 Solar Procurement, approximately 5,100 MW of projects bid into the Request for Proposals (RFP), and the range of project bids inclusive of network upgrades can be significant.[36] P1 Fall Supplemental would require the procurement of at least 4,250 MW of new solar and solar plus storage, which would have resulted in nearly every bid being accepted, including projects that would not otherwise be competitive.

Q. Would P1 Fall Supplemental be least cost if the adder was removed?

A. No. Even with the adder removed, the costs of P1 Fall Supplemental are significantly higher than P2 Fall Supplemental and P3 Fall Base, as seen in Table 3.

[36] For illustrative purposes only, the most competitive bid (inclusive of network upgrade costs) might be $60 per MWh, while the most expensive bid might be $180 per MWh.

Table 3: Duke Base Portfolio PVRR

Portfolio	Interim Compliance Year	PVRR through 2038 ($B)	PVRR through 2050 ($B)	Increase Over Least Cost
P1 Fall Supplemental	2030	$94.2	$182.8	23%
P1 Fall Supplemental *(no adder)*	2030	$86.5	$164.1	10%
P2 Fall Supplemental	2033	$81.0	$154.9	4%
P3 Fall Base	2035	$77.9	$149.0	Least Cost

Q. Did the PVRR estimates for Duke's portfolios increase in the SPA?

A. Yes, the cost estimates increased substantially. The PVRR through 2050 for Duke's recommended portfolio in the initial filing (P3 Base) was estimated at $119 billion; in the SPA, the PVRR of Duke's recommended portfolio (P3 Fall Base) increased by 25% to the $149 billion shown in Table 3.

Q. Please explain why there is an increase in the PVRR estimates.

A. There are two drivers of the increased PVRR estimates. The most obvious factor is the increase in load growth – higher load means more generation needs to be built and more fuel needs to be purchased, which will increase the PVRR. The PVRR does not take into account the impact to a customer's bill, and it is therefore possible that while PVRR could increase, the corresponding increase in sales may keep the estimated bill impact relatively constant. However, this is not the case due to the second factor that is driving the increased PVRR – capital costs.

In the SPA, Duke also updated capital costs and other financial assumptions for the suite of technologies available to the model.[37] While the changes to capital costs vary by technology, capital costs increased across the board, as summarized in Table 4 below. Table 4 shows, by year, the capital cost change in the SPA. Cells shaded in grey represent years before the technology is able to be selected by the model. As this table shows, most capital costs have increased significantly – for example, in 2035, the first year nuclear SMRs can be selected by EnCompass, SMR capital costs are **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** in the SPA than in the initial filing. Due to the quantity of new capacity needed, these capital cost increases are driving a significant portion of the PVRR increase seen in the SPA.

[37] *See* Supplemental Testimony of Snider et al, Table 1, at 11.

[BEGIN CONFIDENTIAL]

[redacted]

[END CONFIDENTIAL]

Q. Does the Public Staff generally agree with the updated capital costs used in the SPA?

A. Generally, yes, although other witnesses may go into more detail about specific costs. The Public Staff had several concerns with the costs used in the initial filing, including a concern that the cost assumptions used for natural gas plants in the Companies' EnCompass modeling were lower than the estimated costs in two ongoing natural gas CPCN proceedings.[38] The cost increases seen in the SPA reflect what the Public Staff believes are more accurate estimates that reflect the most recent data available as well as the impacts of higher interest rates.

III. INVESTIGATION AND FINDINGS

Q. Please briefly summarize this section of your testimony.

A. This section of my testimony will describe three main issues that I reviewed during my investigation and present my corresponding recommendations. I will address (1) the Public Staff's position on the appropriate interim compliance target, (2) resource availability and interconnection limits, and (3) natural gas risks.

Interim Target

Q. Did the Commission determine the appropriate interim compliance year in its 2022 Carbon Plan Order?

A. In its 2022 Carbon Plan Order, the Commission found that "at this time, it is not appropriate to determine whether it is reasonable or necessary to extend the Interim Target compliance date beyond 2030."[39] The Commission expressed its expectation that Duke would

---

[38] *See* Marshall CT CPCN, Docket No. E-7, Sub 1297; and Person County CC CPCN, Docket No. E-2, Sub 1318.

[39] *See* 2022 Carbon Plan Order, at 19.

continue to pursue compliance with the interim target by 2030, including modeling at least one portfolio with an interim compliance date of 2030 in the next Carbon Plan proceeding. The Commission reaffirmed this commitment to review interim compliance by 2030 in its January 17, 2024 Order Scheduling Public Hearings, Establishing Interventions and Testimony Due Dates and Discovery Guidelines, Requiring Public Notice, and Providing Direction Regarding Duke's Supplemental Modeling (SPA Order), directing Duke to "file a portfolio that meets the 70% reduction by 2030 along with its planned supplemental modeling."[40]

Q. Does the Public Staff agree with Duke's delay of the interim compliance date from 2030 to 2035?

A. No. The Public Staff believes that interim compliance can be achieved earlier than 2035 if targets for solar, battery, wind, and natural gas procurement can be realized. The Public Staff recognizes, however, that the incremental load forecast in the SPA, particularly the forecasted large economic development projects with high load factors, make compliance by 2030 nearly impossible and likely cost prohibitive.

---

[40] *See* SPA Order, at 5.

Q. What was the Public Staff's position on the interim compliance date in the 2022 Carbon Plan proceeding?

A. In the 2022 Carbon Plan proceeding, the Public Staff did not recommend that the Commission authorize a delay in the interim compliance date. The Public Staff did, however, note that N.C.G.S. § 110.9 provides the Commission with flexibility to consider the "optimal timing and generation and resource mix," stating further that a determination to delay the interim compliance date should only be made "after Duke has demonstrated that the interconnection of sufficient resources to meet the interim compliance date by 2030 is not possible."[41] The Public Staff further stated that it had "serious concerns about Duke's ability to interconnect the amount of renewable generation that must be installed by 2030 to meet the targets, particularly given the challenges associated with the required major transmission network upgrades . . ."[42]

The Public Staff testified that while the 2030 target in HB 951 is important, there are other considerations that the Commission must also take into account.

> [T]he Commission also needs to consider . . . cost and execution risk, executability, and reliability as well. And [HB] 951, much like Senate Bill 3, which enacted the

[41] *See* the September 2, 2022 direct testimony of witness Thomas, Docket No. E-100, Sub 179, at 12.

[42] *Id.* at 13.

> [Renewable Energy Portfolio Standard] mandates, provided the Commission flexibility to determine . . . when these targets are met and to protect ratepayers from . . . undue risk, unreliable grid, or excessive cost. And I think the Commission has to consider all of those, part of that three-legged stool, to make its decision on when – what portfolio should be adopted and . . . what interim compliance year should be met."[43]

Ultimately, the Public Staff recommended that Duke take all reasonable steps to comply by no later than 2032, balancing cost, execution risk, and reliability.[44] The Public Staff believes now that the interconnection of sufficient resources to meet the interim compliance date by 2030 is not possible.

Q. What interim compliance year is the Public Staff recommending in this proceeding?

A. In its base modeling portfolios, the Public Staff utilizes a 2034 interim compliance year due in part to the obstacles that arose in modeling earlier compliance years.

Q. Please explain why the Public Staff believes 2030 compliance is not possible.

A. The interim compliance date is inherently tied to the annual interconnection limits imposed on each resource, particularly solar, storage, wind, and natural gas. All else equal, earlier compliance

---

[43] *See* Docket No. E-100, Sub 179, Tr. Vol 22, at 363-364.

[44] *See* Docket No. E-100, Sub 179, Tr. Vol 21, at 294.

generally accelerates the required deployment timelines for solar, storage, and wind, while also increasing costs. Portfolio costs for earlier compliance years increase due to the scale of resource additions, which results in a rapid increase to the Companies' revenue requirement, and because these resources are expected to have lower costs in future years due to technological learning curves.

The Companies' P1 Fall Supplemental, which achieves interim compliance in 2030, makes multiple unreasonable assumptions regarding the ability to interconnect and integrate new generation resources. As shown in Table 5 below, P1 Fall Supplemental requires the interconnection of as much as 4,250 MW of solar in 2028, 2029, and 2030; over 1 GW of battery storage in 2028 and 3.5 GW in 2029; 2.4 GW of offshore wind coming online between 2028 and 2030; and 1 GW of onshore wind in 2030. The Public Staff views these targets as impossible to meet, as described in more detail later in my testimony and in the testimony of witness Metz.

Table 5: New economically selected resource interconnections by year, P1 Fall Supplemental

Resource	2028	2029	2030	2031
Solar (Solar and SPS)	4,275	4,275	4,275	1,575
Batteries (Standalone and SPS)	1,300	3,520	120	40
Onshore Wind	0	0	1,050	300
Offshore Wind	800	800	800	0
Natural Gas (CC and CT)	0	3,483	2,624	0
Total Interconnections (MW)	**6,375**	**12,078**	**8,869**	**1,915**
Coal Retirements	0	-3,050	-3,629	0

Notably, of the three leaseholders of the offshore wind energy areas (WEAs) off the coast of North Carolina, not one is currently positioned to reach commercial operation by 2028. The Public Staff also notes that according to data from the United States Energy Information Administration (EIA) going back to 2017, only one state has ever exceeded 4 GW of annual utility-scale solar interconnections: Texas in 2023.[45] No other state comes close to that level of annual interconnections. While historic performance is not indicative of future performance, it does help put these projections into perspective.

The Public Staff has significant doubts as to whether it is possible to interconnect more than 27 GW of new capacity between 2028 and 2030 while simultaneously retiring more than 6 GW of coal generation, which would be required for interim compliance in 2030.

Q. Did the Public Staff attempt to model other interim compliance years?

A. Yes. As I will discuss later in my testimony, we began our modeling using an interim compliance date of 2032, using aggressive but potentially achievable interconnection limits; however, these model runs were unable to meet the emission reduction target for interim

---

[45] Based on an analysis of data from the EIA's Electric Power Monthly (Table 6.2.B) and Electric Power Annual (Table 4.7.B) reports.

compliance. The model consistently violated the CO_2 limits in the 2028 to 2033 period, as no additional resources were available for interconnection in order to reduce carbon emissions. Even when significantly expanded grid edge resources were modeled for illustrative purposes, a 2032 compliance date resulted in CO_2 violations. In addition, the Public Staff modeled 2030, 2034, and 2035 compliance dates to determine what resource additions would be necessary to meet interim compliance in those years. Despite significant expansion of the resources available, the Public Staff's model runs with a 2030 interim compliance date were also unable to meet the carbon constraints.

Q. Does the Public Staff believe the Commission has the authority to delay the interim compliance target beyond 2032?

A. Yes.[46] North Carolina General Statute § 62-110.9 allows for a delay beyond 2032 in the event that additional time is required for completion of nuclear or wind energy facilities, or if necessary to maintain the adequacy and reliability of the existing grid. As previously stated, the Public Staff does not believe it is possible to interconnect over 27 GW of new generation resources between 2028 and 2030; should the Companies also retire over 6.6 GW of coal

[46] For a more detailed discussion, *see* the September 9, 2022 Comments of the Public Staff, filed in Docket No. E-100, Sub 179, at 4-7.

generation during that same time frame in order to meet a 2030 interim compliance date, it is highly likely that there will be insufficient capacity to meet even weather-normal load, much less extreme winter peaks such as those that occurred during Winter Storm Elliot in December 2022.

Therefore, the Public Staff believes that a delay beyond 2032 is necessary to ensure the adequacy and reliability of the grid. The scale of resource additions and retirements necessary to comply by 2030 simply does not appear to be possible.

Resource Availability and Interconnection Limits

Q. Can you briefly summarize the interconnection limits imposed on the model by Duke?

A. Yes. Table 6 below summarizes the annual and cumulative interconnection limits for each resource in the initial CPIRP (P3 Base) and the SPA (P3 Fall Base) across both DEC and DEP. In addition, there are certain constraints on resource additions that apply to DEC or DEP individually, which are not shown in the table below.

Table 6: Interconnection Limits for P3 Base and P3 Fall Base in the CPIRP

Resource	Initial CPIRP Assumption – P3 Base		Supplemental Planning Analysis Assumption – P3 Fall Base	
	Annual	Cumulative	Annual	Cumulative
Solar (including SPS)	2028-2030: 1,350 MW 2031+: 1,575 MW	N/A	2028-2030: 1,350 MW 2031: 1,575 MW **2032+: 1,800 MW**	N/A
Stand-alone Battery	2027+: 4,400 MW	N/A	**2027: 200 MW** **2028-2029: 500 MW** **2030+: 1,000 MW**	N/A
CT	2029+: 4,250 MW	N/A	**2029+: 2,120 MW**	**4,664 MW (11 CT Units)**
CC	2029: 1,360 MW 2030+: 2,720 MW	4,080 MW (3 CC Units)	2029: 1,360 MW 2030+: 2,720 MW	**8,160 MW (6 CC Units)**
Onshore Wind	2031: 300 MW 2032+: 450 MW	2,250 MW	2031: 300 MW 2032+: 450 MW	2,250 MW
Pumped Storage	2034: 1,680 MW	1,680 MW	**2034: 1,834 MW**	**1,834 MW**
Offshore Wind	2032+: 800 MW	2,400 MW through 2038	2032+: 800 MW	2,400 MW through 2038
Advanced Nuclear	2035: 2 Units	15 Units through 2040	2035: 2 Units	**11 Units through 2040**

Q. What interconnection limits did Duke use for its 2030 interim compliance pathway?

A. The interconnection limits in Table 6 apply to P3 Base and P3 Fall Base, which achieve interim compliance in 2035. Achieving interim compliance earlier than 2035 required adjustments to the availability of solar, storage, wind, and nuclear. P1 Fall Supplemental, which achieves interim compliance in 2030, allows the addition of up to 4,250 MW of solar and solar plus storage from 2028 through 2030; up to 3,300 MW of battery storage in 2030; and up to 2,100 MW of onshore wind in 2030. P1 Fall Supplemental also allows the first offshore wind capacity to be interconnected by 2028, years before even the more advanced Kitty Hawk WEA is expected to reach commercial operation. P1 Fall Supplemental also limits the number of CC units to four, down from six in P3 Fall Base. These interconnection quantities are unreasonable and would be nearly impossible to achieve given Duke's transmission constraints and development timelines in recent competitive solicitations.[47]

Q. What interconnection limits did Duke use for its 2033 interim compliance pathway?

A. P2 Fall Supplemental, which achieves interim compliance in 2033, utilizes far more realistic interconnection limits than P1 Fall Supplemental. It allows the addition of up to 1,875 MW of solar and solar plus storage from 2028 through 2030, increasing to 2,500 MW per year in 2032; increases the battery storage interconnection limit to 700 MW in 2028 through 2029, increasing to 1,300 MW in 2030 and 1,400 MW from 2031-2033; and allows up to 600 MW of onshore wind in 2031 with an additional 750 MW in 2032. P2 Fall Supplemental also allows the first offshore wind capacity to be interconnected by 2031, which would require aggressive near-term action on offshore wind development.

[47] To put the amount of solar required under P1 Fall Supplemental in context, the recent 2023 Solar Procurement targeted 1,435 MW of solar and solar plus storage capacity, and approximately 5,100 MW of projects submitted bids.

While the interconnection limits in P2 Fall Supplemental are certainly more aggressive than P3 Fall Base, the Public Staff believes that the quantity of resources selected in P2 Fall Supplemental are within the realm of possibility, but not without challenges and risks.

Q. Does the Public Staff find the interconnection limits in Duke's P2 Fall Supplemental to be reasonable?

A. Yes, for most resources. In the 2022 Carbon Plan proceeding, the quantity of new resources that could be interconnected in each year – particularly solar and storage – was a significant point of contention among the parties. As previously discussed, the period between approximately 2028 and 2032 is extremely constrained, with significant load growth and limited options for adding new resources. Peak retail demand and retail sales are projected to grow at a compound annual growth rate of 2.6% and 3.2%, respectively, from 2027 to 2032; compared to 1.9% and 2.2%, respectively, from 2024 to 2038.

The Public Staff believes that Duke's assumptions regarding the first year of availability of onshore wind, offshore wind, and advanced nuclear are generally reasonable in both P2 Fall Supplemental and

P3 Fall Base.[48] In order to reach the interim compliance goal earlier than 2035, the Public Staff supports the use of the interconnection limits used in the development of P2 Fall Supplemental and has incorporated these limits, with minor adjustments, into its own modeling. Meeting these dates will require a robust effort by both the Companies and third-party developers, particularly in the case of wind. As discussed in the testimony of witness Lawrence, the Public Staff is making recommendations related to the speed and scale at which the Companies should pursue offshore and onshore wind.

As for the annual solar interconnection limits in P2 Fall Supplemental, the Public Staff generally finds these reasonable for planning purposes. Utility-scale solar interconnections to Duke's system peaked around 2018, with approximately 990 MW of solar capacity interconnected to Duke's system (including Qualified Facilities (QFs) and Duke-owned facilities). Figure 6 is an analysis of state profile data published by the EIA,[49] showing utility-scale solar interconnections across both North and South Carolina. The largest quantity of solar that has been connected in any year to all utilities within both states is approximately 1,150 MW in 2017, when the vast

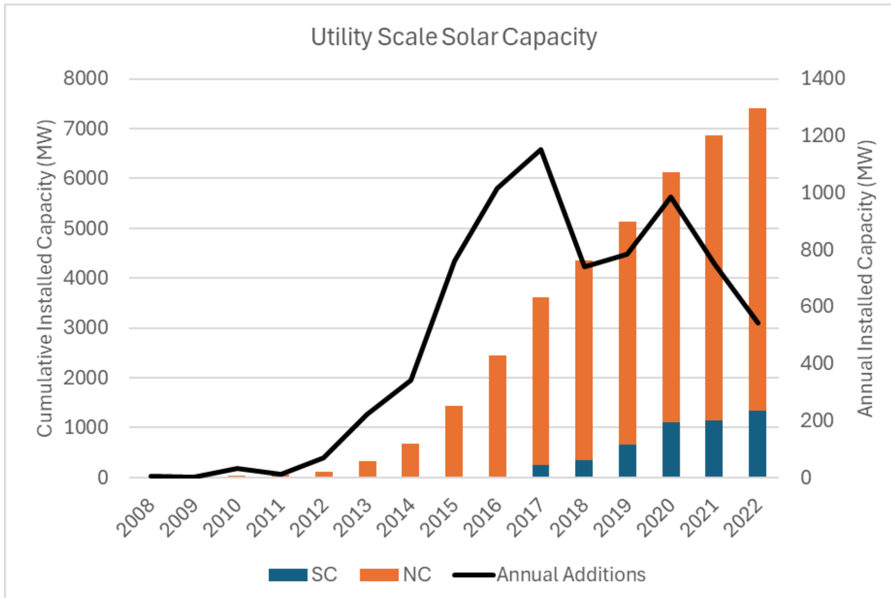
---

[48] Witnesses Lawrence and Metz, respectively, discuss the availability of offshore wind and nuclear in more detail. As discussed later in my testimony, the availability of offshore wind is subject to significant uncertainty.

[49] *See* https://www.eia.gov/electricity/state/southcarolina/ and https://www.eia.gov/electricity/state/northcarolina/.

majority of projects were small-scale, distribution-connected solar facilities.[50]

Figure 6: Utility-Scale Solar Capacity, North Carolina and South Carolina



The initial limits in P2 Fall Supplemental and P3 Fall Base of 1,350 to 1,875 MW annually are likely achievable given the cluster study process and the shift towards fewer but larger transmission-connected projects, assuming that the Companies can properly coordinate transmission outages and complete critical transmission projects in a timely manner, and that RFP attrition[51] can be reduced.

---

[50] Slight differences may exist between QFs interconnecting to Duke's system and the EIA data, due to differences in how each source records a project added to the grid and because EIA data covers all solar installations in North and South Carolina.

[51] RFP attrition refers to winning projects withdrawing after signing a Power Purchase Agreement (PPA) or asset transfer agreement. Attrition had significant negative impacts on the Competitive Procurement of Renewable Energy program.

Achieving the higher levels of 1,800 to 2,500 MW per year by the early 2030s, as called for in P2 Fall Supplemental and P3 Fall Base, will require significant improvements to the interconnection study process, proactive transmission planning, and other creative solutions.

Q. Do these annual and cumulative interconnection limits restrict the model from adding economically selected resources?

A. Yes. While not all these constraints restrict the model in every year, some constraints do restrict the model from adding new resources and are referred to as binding. These binding constraints are most often found in the period between 2027 and 2032, with the exception of the offshore wind and advanced nuclear limits.

For example, in Duke's P3 Fall Base portfolio, the standalone energy storage constraints are binding in 2027, 2028, and 2029, but are not binding again until 2035 when 1,000 MW are added. The solar and solar plus storage constraint is binding from 2028 through 2036, with the exception of 2030.

The constraints for advanced nuclear and wind are also binding. In every year from 2035, when advanced nuclear is first available, through 2048 (with the exception of 2036), the 600 MW limit on advanced nuclear is binding. Likewise, the model selects as much onshore wind as possible from when it first becomes available in

2031, through 2035, as well as the maximum amount of offshore wind in 2033, nearly as soon as it is available. The Public Staff's Base Portfolio similarly selects the maximum amount of new resources as soon as they are available.

Q. What does the frequency of binding constraints in the modeling reveal?

A. Overall, the significant load growth expected by the Companies, coupled with the economic retirement of existing coal assets, is driving unprecedented resource needs in the Carolinas. To serve load at least cost while complying with carbon reduction requirements, the capacity expansion model selects a significant quantity of new resources at a very rapid pace. The fact that so many constraints are so often binding indicates that the underlying process for the interconnection of new resources will be extremely taxed in the coming years as Duke and third-party power producers attempt to interconnect these resources to the grid. Further, a binding constraint indicates that the model would select more of that resource if it could, which would reduce the total cost (assuming larger quantities of resources could be procured at the same cost the model assumes). A binding constraint imposed on the model will tend to increase total costs.

It should also be noted that Duke has set annual interconnection limits on individual resources but has not set an overall limit on the total amount of capacity that is to be added to the system each year. Both P2 Fall Supplemental and P3 Fall Base will require the successful interconnection of over 6 GW of new resources in certain years, particularly in the early 2030s.

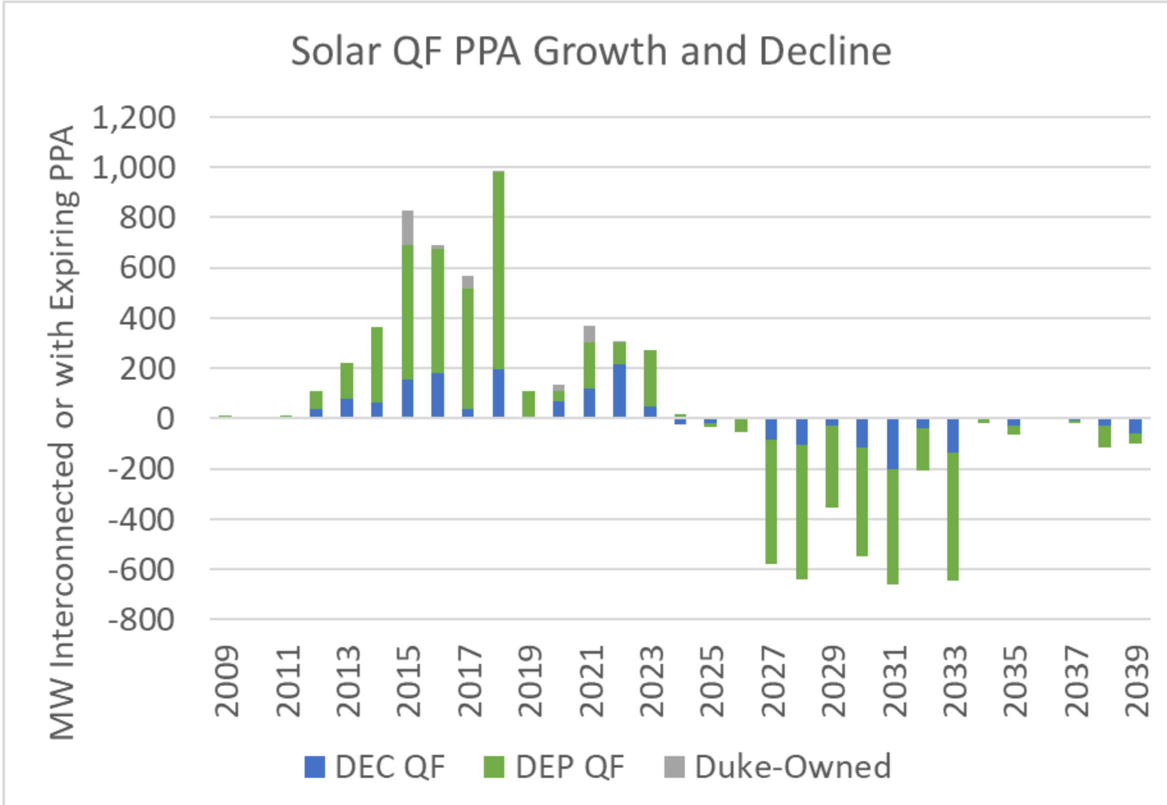
In addition, there is a high concentration of binding interconnection constraints in the period between 2028 and 2032, a critical period in the expansion of Duke's system. High load growth, in particular the load growth projected for high load factor customers associated with new economic development projects, coupled with the retirement of over 2.6 GW of coal generation during this period, creates a significant deficit in the Companies' systems that must be filled by new generating capacity. The interim compliance target further complicates this dynamic, as new carbon-emitting resources built to meet demand risk jeopardizing compliance with HB 951's carbon reduction targets.

Q. Are there any other complicating factors associated with both meeting load growth and achieving carbon emission reduction targets?

A. Yes. North Carolina saw a significant growth of QF solar capacity in the 2013 to 2019 period. As shown in Figure 7 below, from 2013 to

2019, over 3.5 GW of solar QF capacity was interconnected to Duke's system. Between 2027 and 2033, 3.6 GW of this QF solar capacity will come to the end of their PPA terms, typically 10 or 15 years. In its CPIRP, as with past IRPs, Duke assumes that QF capacity will be "replaced in kind." However, if these solar QFs decide to decommission their facilities at the end of their PPA term, there will be a significant gap between the amount of solar needed on the system and the amount actually installed, making future HB 951 compliance more challenging and expensive, as these operational solar QFs must be replaced by new solar facilities. Even if these facilities were to simply continue operating until the end of their operable lives without repowering, we would be faced with a significant missed opportunity.

Figure 7: Interconnection of Solar QFs and Expiring Solar QF PPAs



Q. What do you mean by a "missed opportunity"?

A. As previously mentioned, the higher interconnection levels in excess of 1.5 GW per year will require significant effort and creative solutions. The limits on the interconnection of new resources, particularly solar and solar plus storage, are largely due to the effort and time required to construct new transmission facilities and network upgrades associated with the new generation. However, the large quantity of expiring PPAs during this critical period presents an opportunity to increase the amount of solar and storage interconnected to the system while minimizing expensive transmission upgrades.

As alluded to in Docket No. E-100, Sub 194 (2023 Avoided Cost proceeding),[52] the Public Staff believes that a competitive procurement targeted specifically towards adding solar and/or storage capacity on the distribution grid at existing, operational QF sites has significant potential to interconnect new resources at least cost. If even a quarter of these small QFs repowered with more efficient panels and added energy storage at 50% of the new solar capacity, this effort could add 900 MW of solar and 450 MW of energy storage with less risk of expensive and time-consuming transmission upgrades.

Q. Please describe your recommendation regarding distribution-level competitive procurement.

A. The Public Staff recommends that Duke initiate an RFP specifically for incremental solar capacity and energy storage co-located at existing QFs, either as part of its ongoing transmission-connected annual procurement or conducted in parallel.

---

[52] *See* Reply Comments of the Public Staff, filed on March 27, 2024, in Docket No. E-100, Sub 194, at 8.

The Public Staff notes that such an RFP could allow for incremental solar capacity to be added to the system while avoiding the costly and time-consuming transmission upgrades necessary to integrate new solar resources procured to comply with HB 951. Solar technology has rapidly improved over time, and many small 2 to 5-MW QFs connected to the distribution system and currently selling power to Duke under avoided cost contracts were executed between 2013 and 2016. Commercial solar panels available at that time were approximately 300 watts using direct current (W_{DC}) per panel.[53] Solar panels available today are nearly double that capacity.[54] If solar QFs are located on distribution circuits that can host additional capacity, repowering the facility would increase the export capacity and result in minimal additional upgrades.[55] In situations where the distribution feeder is constrained or additional output from the facility would impact the transmission system, the facility could be repowered, increasing the DC capacity, but the existing export capacity limit could be maintained and energy storage could be added to store and

[53] For examples, see the CPCN applications in Docket Nos. SP-2363, Sub 6 and SP-2363, Sub 9 (filed in 2014, 4.99 MW facilities using 300 W panels); Docket No. SP-5196, Sub 0 (filed in 2015, 4.99 MW facility using 300 W panels).

[54] For examples, see the CPCN applications filed in Docket Nos. SP-60462, Sub 0 (filed in 2023, 4.99 MW facility using 585 W panels); Docket No. SP-62430, Sub 0 (filed in 2024, 80 MW facility using 600 W panels); Docket Nos. SP-62437, Sub 0 and SP-62438, Sub 0 (filed in 2024, both 80 MW facilities using 615 W panels).

[55] Some re-study would be required for facilities adding storage, as solar-only QFs were only studied during daylight hours during the interconnection process.

discharge the incremental carbon-free energy when it is needed most.

For facilities that seek to add storage to avoid network upgrades or for any other reason, the bids should be specified in $/MW-month, similar to the existing solar plus storage bids in the 2023 Solar Procurement[56] and 2024 Solar Procurement.[57] Duke could set a target for additional storage, open the bids to existing QFs, and pay the QFs for their storage via a PPA that provides Duke control over the storage device or, in the absence of direct control, clear and flexible dispatch signals.

Q. Are there challenges associated with your proposed competitive procurement?

A. Yes. The Public Staff acknowledges that there are complex technical and commercial issues to resolve in order to enable such a procurement, such as the appropriate quantities of solar and storage to procure, the cost caps and ratepayer protection guardrails that would be necessary to ensure projects are cost competitive, the dispatch and control structure for projects with energy storage, and the sophistication of distribution-level QF solar developers relative to the larger transmission-connected solar developers that participate

[56] Docket Nos. E-2, Sub 1297 and E-7, Sub 1268.

[57] Docket Nos. E-2, Sub 1317 and E-7, Sub 1290.

in the ongoing solar procurements. As such, the Public Staff recommends that the Commission direct Duke to convene a stakeholder process with solar and storage developers to design a competitive procurement and pro forma PPA targeted towards smaller, less sophisticated distribution-connected projects, integrated into the 2025 Solar Procurement cycle. A distribution-level competitive procurement could enable Duke to reach the higher levels of solar and storage interconnection needed in the CPIRP.

Q. Do you recommend any other creative solutions to the interconnection challenges you describe in your testimony?

A. Yes. I believe that there is some potential for new transmission-connected solar and storage resources to be added at the site of existing fossil fuel generators utilizing the established Surplus Interconnection Request[58] or Generator Replacement Request[59] process. This process, colloquially referred to as "clean repowering," allows a new generation facility to interconnect at the point of interconnection (POI) of an existing resource generally without significant transmission system impacts.[60] This process is identified

[58] FERC Large Generator Interconnection Process, Section 4.3.

[59] FERC Large Generator Interconnection Process, Section 4.9.

[60] In the case of a Surplus Interconnection Request, the maximum export capacity at the POI cannot be exceeded. In the case of a Generator Replacement Request, only the incremental capacity above the existing POI export rights is studied.

as a potential solution to interconnection backlogs in the DOE's April 2024 Transmission Interconnection Roadmap.[61]

Clean repowering has the greatest potential at CT sites but could have potential at coal and CC sites as well. Because a CT operates very few hours each year but has reserved export capacity rights equal to its full output, CTs are particularly good candidates for clean repowering given the many hours of the year when the export capacity at the CT's POI is unused. Connecting solar or battery resources at the CT POI under a Surplus Interconnection Request could avoid, or significantly reduce, required transmission upgrades for the new resource, thus reducing total costs as well as enabling faster interconnections of solar and storage resources that are not dependent on system upgrades. The Companies are already utilizing this process to interconnect a 25-MW battery at DEC's 55-MW Monroe solar facility, resulting in "reduced costs and a significantly reduced development timeline compared to storage projects using a new interconnection."[62] DEC's proposed battery storage investment at the retiring Allen coal plant is another example of clean

---

[61] *See* Section 2.5. Report is available at https://www.energy.gov/sites/default/files/2024-04/i2X%20Transmission%20Interconnection%20Roadmap.pdf.

[62] *See* the Direct Testimony of Laurel M. Meeks and Evan W. Shearer, filed on January 19, 2023, in Docket No. E-7, Sub 1276, at 9.

repowering,[63] as is Xcel's investment in 710 MW of solar and energy storage at the Minnesota Sherco coal generator complex.[64]

The Public Staff notes that clean repowering can avoid or significantly reduce the risks that contribute to the annual solar interconnection constraint, including third-party contracting delays and termination risk, planning complexities caused by system and transmission upgrade needs and project size, and outage increases and reliability impacts.[65] Further, the interconnection of solar and battery storage at these POIs could qualify as EIR-eligible project investments, which means that these investments are likely to be approved if included in an EIR application.

The Public Staff recommends that the Commission direct Duke to study the interconnection of solar and battery storage resources at existing fossil generator sites across its footprint as soon as possible in order to reduce costs and development timelines, and to include such projects in future competitive procurements as self-developed

---

[63] *Id.*, Exhibit 2, at 11. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[64] *See* Eric Wesoff, "*Minnesota's Biggest Solar Project Will Help Replace A Huge Coal Plant,"* Canary Media, May 1, 2024, https://www.canarymedia.com/articles/solar/minnesotas-biggest-solar-project-will-help-replace-a-huge-coal-plant?utm_campaign=canary-social&utm_source=twitter&utm_medium=social&utm_content=1714570318.

[65] *See* the Verified Petition for Approval of 2023-2024 Carbon Plan and Integrated Resource Plans of DEC and DEP, Appendix I at 8 and Appendix L at 19.

projects.[66] It appears that Duke may have already utilized this process to an extent in the development and selection of its Robinson solar project in the 2022 solar procurement. The planned 76-MW solar facility will be located at the retired Robinson coal plant and operational Robinson nuclear plant.[67]

The Public Staff also notes that lengthy interconnection timelines associated with new resources are not unique to the Carolinas. The Lawrence Berkeley National Laboratory (LBNL) found that interconnection wait times are lengthening across the country as interconnection queues grow. The typical project built in 2023 took nearly five years from the interconnection request to commercial operation, compared to three years in 2015 and less than two years in 2008.[68] The FERC addressed these bottlenecks in its Order No. 2023, which requires improvements to generator interconnection requests and agreements,[69] and its Order No. 1920, which requires improvements to long-term transmission planning and cost

---

[66] The maximum benefit from a surplus interconnection request can depend on proper coordination between both the new renewable resource and the existing fossil generator, which is maximized when the utility owns and operates both resources.

[67] *See* https://news.duke-energy.com/releases/duke-energy-progress-looks-to-add-solar-power-in-eastern-south-carolina-as-part-of-diverse-plan-to-support-booming-growth.

[68] *See* the LBNL "Queued Up: 2024 Edition", available at https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf.

[69] *See* https://www.ferc.gov/media/e-1-order-2023-rm22-14-000.

allocation.[70] The DOE's Transmission Interconnection Roadmap referenced above goes beyond the requirements of Order No. 2023, and lays out many potential solutions to these challenges based on extensive stakeholder feedback.

Q. Is Duke taking any action to facilitate interconnections?

A. Yes. During stakeholder meetings for the 2024 Solar Procurement, Duke proposed a limited modification of the North Carolina Interconnection Procedures to allow for provisional interconnection service for state-jurisdictional projects. This process, which already exists for FERC-jurisdictional projects, would allow state projects to deliver energy at a reduced capacity and subject to curtailment while the required transmission upgrades are completed. While this approach is not without challenges, it could provide an avenue for projects dependent on large, long lead-time transmission upgrades to reach commercial operation more quickly while still maintaining grid reliability.

In addition, Duke is already working to accelerate planned battery storage projects. In DEC's recent general rate case, it proposed a 50-MW battery to be sited at the retiring Allen coal site. **[BEGIN CONFIDENTIAL]** [redacted]

[70] *See* https://www.ferc.gov/media/e1-rm21-17-000.

[redacted] [END CONFIDENTIAL] In DEP's recent general rate case, it proposed a 100-MW battery at the Knightdale substation that would come online in phases, with 50 MW online in 2025, 20 MW added in 2028, and 30 MW in 2040. **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

Natural Gas

Q. Is the Public Staff concerned about Duke's planned natural gas buildout represented in P3 Fall Base?

A. Yes, to an extent. While the Public Staff's modeling suggests that new natural gas units, both CCs and CTs, are necessary to meet load and maintain system reliability, natural gas comes with significant regulatory risk. As discussed in more detail in witness Nader's testimony, the recently finalized EPA Clean Air Act rules require new natural gas plants that operate at an annual capacity factor of more than 40% to control carbon emissions through carbon capture and sequestration (CCS) by 2032.[71] Should these rules survive legal challenges, they could lead to either underutilization of

[71] For an analysis of the Clean Air Act rules that describes the standards for new natural gas facilities, *see* https://eelp.law.harvard.edu/2024/04/timelines-of-epas-final-rules-to-reduce-climate-changing-pollution-from-power-plants/.

these assets as output is lowered from an expected 60-80% to below the 40% annual limit, or require significant capital investments to retrofit the plants with CCS. Environmental regulations, as well as uncertainty regarding the materialization of new economic development load in the Carolinas, underlie the Public Staff's concern with Duke's plans to file five CPCN applications for natural gas CCs before the next CPIRP is approved in late 2026.

Q. Did Duke model the EPA's proposed Clean Air Act rules?

A. Yes. Although the rules were recently finalized in April 2024, Duke provided two pathways to compliance in its initial filing based upon the rules as proposed at the time. The first pathway assumed hydrogen blending standards for existing and new natural gas plants, forcing approximately 10% hydrogen blending by 2032 and 96% by 2038.[72] The second pathway limited the capacity factor of existing coal and natural gas facilities, as well as new natural gas, in such a way as to avoid hydrogen blending or CCS requirements.[73]

In its SPA, Duke did not submit additional sensitivities examining the impact of the proposed rules under the increased load forecast.

[72] The proposed rules appear to have mandated a 30% hydrogen blending standard by 2032. It is unclear why Duke chose to model a 10% hydrogen blending standard in its EPA modeling.

[73] As discussed in witness Nader's testimony, baseload units are subject to the most stringent requirements, which can be avoided if the generators operate below the threshold.

Witness Michna discusses Duke's EPA model runs in more detail, highlighting the load increase that would be required if hydrogen production was assumed to be located in Duke's territories.

Tax Credits

Q. Please explain how Duke incorporated tax credits from the IRA in its modeling.

A. Duke incorporated the IRA's production tax credits (PTC) and investment tax credits (ITC) into its modeling by reducing the revenue requirement associated with eligible resources. Solar, wind, and new nuclear received the PTC, while energy storage received the ITC. These tax credits were modeled under the assumption that Duke would satisfy the prevailing wage requirements, thus receiving a higher ITC and PTC (approximately 30% for the ITC and $30 per MWh for the PTC). For energy storage, some proportion of projects were assumed to be located in energy communities, increasing the available ITC to 40%.

It should be noted that the IRA's tax credits have a sunset provision that phases out the tax credits over a three-year period that begins in the first calendar year after the later of (1) 2032 or (2) a determination that annual greenhouse gas emissions from electricity generation are 75% lower than 2022.[74] Based on a review of several studies of national greenhouse gas emission trajectories, Duke has made the assumption that the tax credits will extend throughout the planning horizon (i.e., until 2050).[75]

Q. Does this assumption present any particular risks to executing the least-cost plan?

A. Yes. All of the expansion plans presented by both Duke and the Public Staff utilize this same assumption, which results in a lower cost for any eligible resource placed into service in 2033 and beyond. Should this assumption turn out to be incorrect and the tax credits phased out earlier than 2050, there will likely be a significant impact on total costs and resource selection. This would likely impact offshore wind and advanced nuclear the most, as these are capital-intensive resources that are not expected to be available until the mid to late 2030s. This risk underscores the importance of taking actions today that will enable Duke to reasonably accelerate offshore wind and new nuclear, as the risk of losing access to these tax credits grows with each year of delay.

---

[74] *See* 26 U.S.C. § 48E(e) (2022).

[75] *See* CPIRP Chapter 2, at 42.

IV. PUBLIC STAFF MODELING

Q. Please briefly summarize this section of your testimony.

A. This section of my testimony will provide an overview of the Public Staff's modeling process and describe several changes I made to Duke's modeling inputs based upon my own investigation and the investigation of other Public Staff witnesses. I will briefly summarize insights gained from the modeling modifications, but the primary purpose of this section of my testimony is to support the Public Staff's proposed NTAP as described in the testimony of witness Metz.

Q. Please summarize the process the Public Staff followed in developing its CPIRP positions.

A. The Public Staff began by reviewing the EnCompass input files provided by the Companies with their initial filing and using them to recreate Duke's EnCompass database, which consists of numerous scenarios and many individual datasets. The Public Staff then re-ran Duke's portfolios to validate that similar results were achieved. In most instances, similar results were achieved, although due to differences in computer hardware, slight variations in resource selection and dispatch were noted.

After validating Duke's portfolios, the Public Staff modified those datasets based on its investigation, which involved creating or modifying certain resources, modeling assumptions, load forecasts, and other inputs. These modified models were run to generate base portfolios and sensitivities.

Q. Please describe the Public Staff's base portfolios and sensitivities.

A. The Public Staff structured its modeling to examine several different interim compliance years, including 2030, 2032, 2034, and 2035. Because the year chosen for interim compliance has such a profound impact on the modeling results, these different pathways enabled the Public Staff to understand how the interim compliance year drove resource selection and portfolio costs. In addition, the Public Staff ran multiple sensitivities on each portfolio, as described later in my testimony. While my testimony describes the details of these modeling portfolios and draws conclusions from the results, witness Metz discusses the impact on the NTAP in more detail.

Carbon Constraint and Interim Compliance

Q. What interim compliance years did the Public Staff consider in its modeling?

A. While the Public Staff's base portfolio is presented with a 2034 interim compliance year, the Public Staff also ran sensitivities with 2030, 2032, and 2035 interim compliance dates. The results of this modeling, and sensitivities within each interim compliance year, support the Public Staff's positions and base portfolio in this proceeding. Broadly speaking, based on the 2028-2032 resource additions shown in Table 7 below, there is minimal difference between the resources needed for compliance in 2034 and 2035, relative to the significant additions needed under earlier compliance years. A 2034 interim compliance date requires aggressive action but is still potentially achievable.

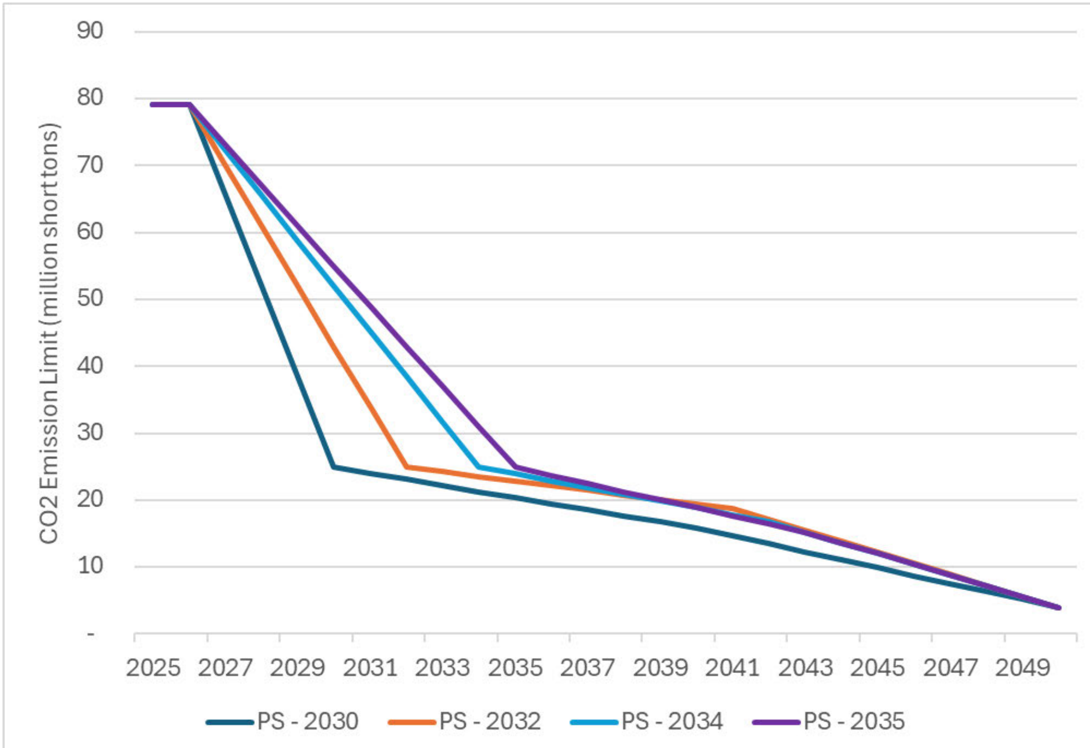
Table 7: Public Staff resource additions from 2028 through 2032 based on interim compliance year (MW)

Resource Deployments (2028 - 2032)	**PS - 2030**	**PS - 2032**	**PS - 2034**	**PS - 2035**
Nuclear	0	0	0	0
Solar (Solar and SPS)	19,500	10,200	9,150	9,150
Batteries (Standalone and SPS)	13,880	11,880	2,900	2,240
Onshore Wind	2,250	1,350	1,050	1,050
Offshore Wind	0	2,200	2,200	2,200
Natural Gas CC	5,436	6,796	4,077	5,436
Natural Gas CT	1,270	4,629	1,270	1,270
Total Interconnections (MW)	**42,337**	**37,055**	**20,648**	**21,347**
Coal Retirements	-4,406	-4,406	-4,406	-4,406

Q. You previously described how Duke implemented its carbon constraint. Did the Public Staff modify these constraints in its own modeling?

A. Yes. Due to challenges in meeting load in the near-term while complying with carbon constraints, and the availability of additional carbon-free generation sources in the mid to late 2030s, the Public Staff slightly relaxed the carbon constraints immediately following the interim target, allowing additional time for new nuclear and wind resources to contribute to the generation mix. The Public Staff's carbon constraints are shown in Figure 8.

Figure 8: Public Staff Carbon Constraints for 2030, 2032, 2034, and 2035 Interim Compliance



Q. Did the Public Staff allow the selection of new natural gas resources?

A. Yes. In most portfolios, including the base case portfolio, the proposed South Carolina CC was removed and all emissions from undesignated future units were counted towards the carbon cap. In every model run that permitted the selection of natural gas, both CCs and CTs were economically selected as part of the least-cost path to carbon neutrality. Natural gas emits approximately half of the carbon per MWh as coal, and the retirement of over 8 GW of coal capacity by 2036 must be part of an overall transition that either maintains or improves upon grid reliability. In this context, the scale of anticipated load growth and the impact of coal retirements cannot be understated.

As discussed in the testimony of witnesses Michna and Metz, the Public Staff has significant concerns regarding the stranded asset risk associated with new natural gas resources, including the impact the recently finalized EPA rules might have on their costs and operations. However, restricting the model from building any gas plants requires the deployment of unrealistic amounts of solar and batteries while potentially putting grid reliability at risk, particularly if large load customers materialize at the expected or a higher-than-expected rate. Because many of the new, large load customers have a very high load factor (over 90%), they require a significant amount of energy and round-the-clock generation. Meeting this new load, which is likely to materialize prior to the availability of wind and new nuclear plants, entirely with solar and storage is a significant challenge. A 300-MW data center operating at a 98% load factor would require over 1,000 MW of solar to produce the required energy, while significant quantities (well over 300 MW) of battery storage would need to be added to shift the energy to where it is needed.

The Public Staff notes that there are many Duke customers who have provided public testimony and filed consumer statements of position in this proceeding in opposition to the building of new gas plants. Multiple intervenors in the 2022 Carbon Plan proceeding also opposed the inclusion of new gas plants in the Carbon Plan. The Public Staff explored this concept through the modeling of a portfolio with a 2030 interim compliance date, with and without new natural gas CCs. When new CCs were prohibited, the Public Staff permitted the model to select up to nine total CTs to ensure reliability. As discussed below, the model relied heavily on new CTs when it could not build new CCs.

Q. Please describe the results of the Public Staff's 2030 interim compliance date modeling.

A. The Public Staff modeled a resource portfolio with a 2030 interim compliance date and several sensitivities: (1) base accelerated resource interconnection assumptions; (2) base accelerated resource interconnection assumptions and no new CC units; and (3) base accelerated resource interconnection assumptions, no new CC units, and significantly expanded grid edge programs.[76] The

[76] As discussed in witness Williamson's testimony, the expanded grid edge sensitivity doubles forecasted participation in EE, DSM, rooftop solar, and critical peak pricing tariffs.

resource additions required by each of these scenarios is presented in Table 8 below.

Table 8: Public Staff 2030 Modeling Resource Selections (MW)

Resource Deployments (2028 - 2031)	2030 Base	2030 No CC	2030 No CC, High Grid Edge
Solar (Solar and SPS)	16,425	16,425	15,975
Batteries (Standalone and SPS)	13,540	16,320	15,500
Onshore Wind	2,250	2,250	2,100
Offshore Wind	0	1,100	1,100
Natural Gas CC	5,436	0	0
Natural Gas CT	1,274	4,169	3,398
Total Interconnections (MW)	**38,926**	**40,264**	**38,073**
Coal Retirements	-3,088	-3,088	-3,088

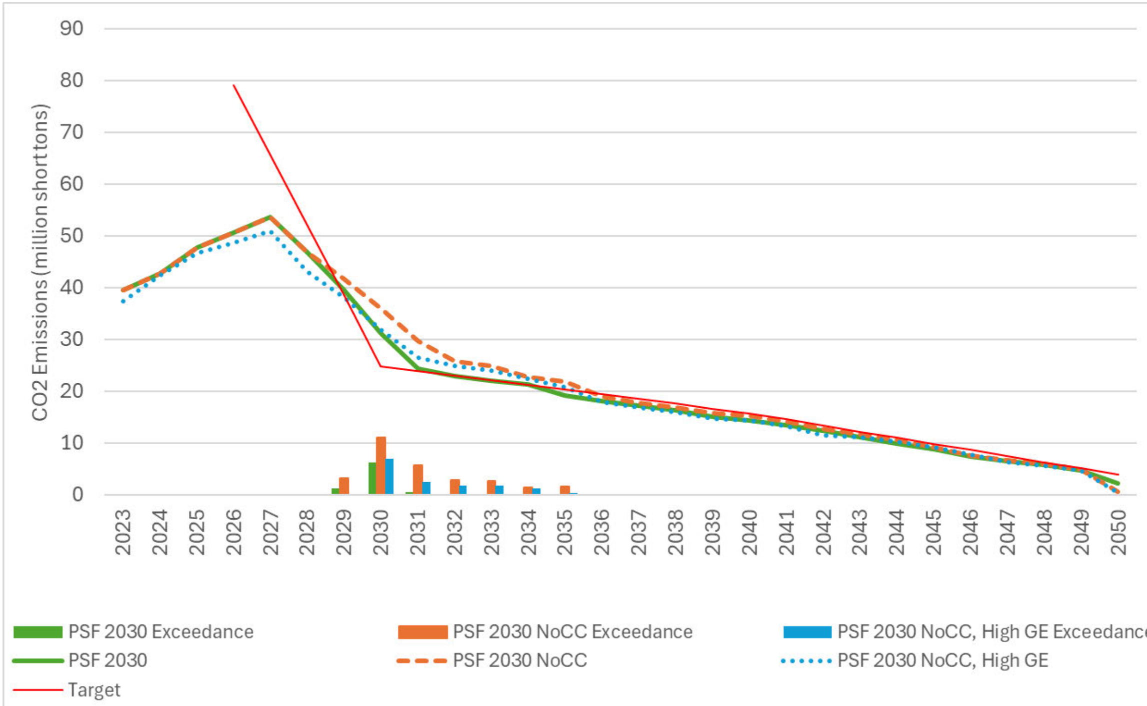
As previously discussed in my testimony, it is difficult to grasp the sheer scale of resource additions that would be required to implement these portfolios, particularly when the model is not allowed to select a new CC. Assuming that no CCs are built and Grid Edge cannot be significantly increased beyond Duke's baseline projections, the 2025 and 2026 solar procurement cycles would each need to target procurement of more than 4 GW of solar, and the pace of wind and storage development would need to be accelerated and expanded to an unrealistic extent.

Q. Putting aside the scale of resource additions required to meet the interim compliance target by 2030, did these simulations meet the carbon cap?

A. No. In both cases where no CC was added, the model was overly constrained and was unable to meet the CO_2 limit, as shown in Figure 9.[77] The model run with no CCs and base grid edge assumptions did not comply with the interim target until 2034; when the high grid edge sensitivity was included, the interim target was met in 2032. While the 2030 portfolio had fewer exceedances when it was allowed to build CCs, it still violated the limit in 2030, and the interim compliance target was not achieved until 2031.

[77] This figure shows the emissions relative to the target from the production cost runs, which have the carbon constraint removed to facilitate weekly dispatch optimization. However, even the capacity expansion models saw violations of the CO_2 limit.

Figure 9: CO_2 Emissions and Exceedances in 2030 Portfolios



Q. Please describe the results of the Public Staff's 2032 interim compliance date modeling.

A. The Public Staff modeled a resource portfolio with a 2032 interim compliance date and several sensitivities: (1) base accelerated resource interconnection assumptions; and (2) base accelerated resource interconnection assumptions and the same significantly expanded grid edge programs used in the Public Staff's 2030 model runs. The resource additions required by each of these scenarios is presented in Table 9 below. While this buildout is significantly less than that called for under a 2030 interim compliance date as shown in Table 8, it still requires a significant quantity of resources and therefore poses significant challenges. In particular, the quantity of energy storage required to reach the interim compliance target by 2032 is concerning. Similar to the 2030 portfolios discussed above, without the high grid edge sensitivity, the base 2032 portfolio violates the CO_2 emission limits from 2030 through 2032, not reaching the interim target until 2033.

Table 9: Public Staff 2032 Modeling Resource Selections (MW)

Resource Deployments (2028 - 2031)	**PS - 2032**	**PS - 2032 - High Grid Edge**	**Delta**
Nuclear	0	0	0
Solar (Solar and SPS)	7,725	7,725	0
Batteries (Standalone and SPS)	9,460	7,080	(2,380)
Onshore Wind	600	600	0
Offshore Wind	1,100	1,100	0
Natural Gas CC	4,077	4,077	0
Natural Gas CT	4,633	1,274	(3,359)
Total Interconnections (MW)	**27,596**	**21,857**	**(5,739)**

Resource Availability

Q. Please describe the resource availability assumptions used by the Public Staff in its base portfolio.

A. The Public Staff largely based its resource availability assumptions on Duke's P2 Fall Supplemental model, which represents an aggressive but potentially achievable target for new solar, storage, and wind resources. Adjustments that were made to Duke's P2 resource availability assumptions include keeping a lower interconnection limit for solar plus storage relative to standalone solar, accounting for risks in the battery supply chain. In most model runs, the Public Staff allowed up to six CCs to be selected, although the South Carolina CC was not included in the model. Finally, the Public Staff modeled the first available block of offshore wind as available in 2031, which would correspond roughly to the procurement of energy from the Kitty Hawk facilities, which are further along in development than Carolina Long Bay. A summary of the Public Staff's resource availability limits, compared to Duke's P3 Fall Base assumptions, is shown below in Table 10, with differences shown in bold.

Table 10: Interconnection Limits for P3 Fall Base and the Public Staff's 2034 Base

Technology	Duke P3 Fall Base Assumptions		Public Staff 2034 Base Assumptions	
	Annual	Cumulative	Annual	Cumulative
Stand-alone Solar	2028-2030: 1,350 MW 2031+: 1,575 MW 2032+: 1,800 MW	N/A	**2028-2030: 1,875 MW** **2031+: 2,100 MW** **2032+: 2,475 MW**	N/A
Solar Plus Storage			2028-2029: 1,350 MW **2030: 1,875 MW** **2031+: 2,100 MW** **2032+: 2,475 MW**	N/A
Stand-alone Battery	2027: 200 MW 2028-2029: 500 MW 2030+: 1,000 MW	N/A	**2027: 300 MW** **2028: 800 MW** **2029: 900 MW** **2030+: 1,300 MW**	N/A
CT	2029+: 2,120 MW	4,664 MW (11 CT Units)	2029+: 2,120 MW	**5,088 MW** **(12 CT Units, no H2 CT)**
CC	2029: 1,360 MW 2030+: 2,720 MW	8,160 MW (6 CC Units)	2029: 1,360 MW 2030+: 2,720 MW	8,160 MW (6 CC Units)
Onshore Wind	2031: 300 MW 2032+: 450 MW	2,250 MW	**2031: 600 MW** **2032+: 750 MW**	2,250 MW
Pumped Storage	2034: 1,834 MW	1,834 MW	2034: 1,834 MW	1,834 MW
Offshore Wind	2032+: 800 MW	2,400 MW through 2038	**2031+: 1,100 MW**	**5,500 MW** **through 2038**
Advanced Nuclear	2035: 2 Units	11 Units through 2040	2035: 2 Units	**11 Units** **through 2040**

Q. You previously testified that you believe the resource availability assumptions in Duke's P2 Fall Supplemental were "within the realm of possibility." Please explain how you arrived at this conclusion.

A. I would first point out that the resource availability assumptions used by the Public Staff differ from Duke's P3 Fall Base in four main ways: (1) higher levels of standalone solar allowed in 2028 through 2030, and higher levels of standalone solar and solar plus storage allowed in 2030 and beyond; (2) slightly accelerated standalone storage assumptions; (3) higher levels of onshore wind deployments; and (4) more rapid deployment of offshore wind.

As described in more detail in witness Metz's testimony, because the Public Staff's base portfolio relied heavily on solar plus storage, the procurement targets in the Public Staff's NTAP are only marginally greater than Duke recommends – 6,700 MW by 2031, compared to 6,460 MW in Duke's P3 Fall Base. The amount of energy storage in the Public Staff's NTAP is also nearly identical, although more of the storage would be coupled with solar. Based on the results of the Public Staff's modeling, the procurement targets for solar and storage in the Public Staff's NTAP are largely similar to Duke's. While there is divergence in the amount of solar and storage called for in the Public Staff's portfolios beyond the NTAP (i.e., resources in the 2027 and 2028 procurement cycles to be placed in service in 2031 and 2032), those specific quantities will be determined in the next CPIRP proceeding and will be informed by lessons learned during the ongoing competitive procurement cycles. In addition, I have offered several proposals that, if adopted by the Commission and implemented by Duke, could enable the Public Staff's higher forecasted levels of solar and storage interconnection beyond 2030.

With respect to onshore wind resources, the Public Staff's NTAP recommends an additional tranche of 600 MW of incremental onshore wind by 2033, for a total of 1,800 MW. While this target is certainly more aggressive than Duke's target of 1,200 MW, based on the information available to the Public Staff, including the number of potential sites and third-party developer interest, the Public Staff does not view this target as unreasonable. In addition, as noted in witness Lawrence's testimony, onshore wind is an economic resource even without a carbon constraint – deploying this resource at the scale envisioned by the Public Staff should be a priority of the Commission and Duke, as it would result in cost savings for ratepayers.

Finally, the Public Staff notes that its offshore wind assumptions – as much as 1,100 MW available in 2031 – may no longer be achievable. Information that the Public Staff has obtained since its base modeling assumptions were locked down leads me to believe that the earliest possible date for offshore wind deployment would be 2032, associated with a Kitty Hawk WEA, while development of offshore wind at either of the two Carolina Long Bay[78] sites would take longer. As described in more detail in witness Lawrence's testimony, the

[78] Carolina Long Bay East is owned by an unregulated Duke Energy (Duke Energy Corporation is the parent company of DEC and DEP, with electric and natural gas service territories in North and South Carolina, Tennessee, Ohio, Kentucky, Indiana, and Florida) affiliate.

Public Staff is concerned that Duke's proposal to conduct an Acquisition Request for Information (ARFI) and report the results back in the next CPIRP is essentially a "re-do" of the request for information (RFI) that Duke conducted in 2023 and reported in this proceeding. Duke's proposed structure and timeline for the ARFI may result in an unnecessary delay in the development of offshore wind; in addition, without the modifications to the ARFI proposed by witnesses Lawrence and Metz in their testimonies, there is no indication that the Companies' proposed ARFI is appropriately scoped to provide the information needed.

That being said, based on concerns related to timelines for offshore wind development, the Public Staff did explore two sensitivities with offshore wind: (1) limiting the total amount to 2,200 MW, with the first block available in 2033; and (2) limiting the total amount to 2,200 MW, with the first block available in 2035. The results of these analyses are presented in more detail in witness Metz's testimony; however, neither sensitivity results in significant changes to the Public Staff's NTAP with respect to solar, storage, or onshore wind.

Q. What resource sensitivities did the Public Staff model?

A. The Public Staff explored a variety of resource availability sensitivities, most of which were based on the Public Staff's base 2034 model. These sensitivities included:

1. EIR removal – removing the assumed impact of the EIR program.

2. Accelerated nuclear – allowing the first nuclear unit to come online in 2031.

3. Limited batteries – constraining the model to a slower battery deployment scenario to represent potential supply chain risks.

4. Limited offshore wind – allowing no more than 2.2 GW of offshore wind to be selected, aligned with the procurement of only Carolina Long Bay. These sensitivities explored in-service dates of 2033 and 2035, reflecting uncertainty regarding the pace of development.

5. Limited natural gas – allowing the selection of only four CCs and up to 10 CTs.

6. GHG rule implementation –imposing restrictions on future gas generators to exempt them from CCS requirements imposed on baseload plants in the EPA's CAA rule published on April 27, 2024.

Q. What insights did the Public Staff gain from these sensitivities?

A. These model runs were illustrative in exploring how different risks or opportunities could influence the selection of new resources. Of particular note is the accelerated nuclear sensitivity, which had two impacts: first, only four CCs were selected by the model; second, only 1.1 GW of offshore wind was selected, and not until 2038. As discussed by witness Metz, this accelerated nuclear sensitivity was perhaps the most influential in changing resource portfolios, illustrating the importance of nuclear in meeting the carbon reduction targets. The amount and timing of offshore wind was also one of the most significant variations as resource assumptions changed. The remainder of my testimony will describe several of these sensitivities and their relationship to the NTAP.

Department of Energy Loan Program Office[79]

Q. Please describe the EIR Program.

A. The EIR is a federally backed loan program created by the IRA that is primarily intended to finance projects that reinvest in energy infrastructure throughout the United States. The IRA authorized the DOE Loan Programs Office (LPO) to administer up to $250 billion in guaranteed federal loans, which can be used to finance energy-related projects that achieve significant and credible greenhouse gas

[79] The Public Staff engaged the Rocky Mountain Institute (RMI) for federally funded technical assistance on the EIR program. RMI staff executed the necessary non-disclosure agreements to assist the Public Staff and worked with the Public Staff to identify EIR funding opportunities.

pollution reductions.[80] EIR loans can provide debt financing at lower rates than corporate debt,[81] which enables projects receiving EIR funding to create ratepayer savings. A condition of EIR loans is that benefits must be passed on to the customers of recipient utilities. Notably, when applied to tax credit eligible resources and investments, EIR loans can be used in tandem with tax credits, preserving the value of the credits and multiplying the savings.

Q. Why is it important for the Commission and the Companies to consider the EIR program in the CPIRP?

A. Utilities must submit an EIR application to LPO prior to project completion in order to be considered for the program. By statute, EIR funds must be conditionally committed to an applicant by September 30, 2026, after which time the authorization for the program is set to expire. The program's disbursement end date is September 31, 2031, and EIR loans must either be (1) spent on projects that enter into service by that date, or (2) allocated towards project milestones that are completed by that date.

---

[80] Details on eligible projects and program requirements are laid out in the Title 17 Program Guidance, at 25.

[81] *The Energy Infrastructure Reinvestment Program Emerging; Opportunities from the DOE Loan Program Office's Upgraded Toolkit,* Charles River Associates, 2022, https://media.crai.com/wp-content/uploads/2022/12/21120848/CRA-Whitepaper-The-Energy-Infrastructure-Reinvestment-Program-FEBRUARY-REVISION-1.pdf.

These time constraints render the current CPIRP critical for identifying new clean energy projects, grid investments, and reinvestments in existing energy infrastructure that (1) qualify for the EIR program; (2) can meaningfully reduce utility emissions; (3) will be able to complete construction by September 30, 2031; and (4) can be incorporated into an application for an EIR loan to DOE LPO in time for conditional approval prior to September 30, 2026.

Q. What resources and project types are eligible for EIR loans?

A. There are two categories of eligible EIR project investments. Category 1 investments retool, repower, repurpose, or replace energy infrastructure that has ceased operations. If a Category 1 project involves electricity generation through the use of fossil fuels, it is required to have controls or technologies to avoid, reduce, utilize, or sequester air pollutants and emissions of greenhouse gases. Category 2 investments enable operating energy infrastructure to avoid, reduce, utilize, or sequester air pollutants or greenhouse gas emissions.

EIR eligible projects do not need to be sited *exactly* where the retired or to-be-retired infrastructure is located. As long as new investments “replace the [electricity and grid balancing] services no longer provided by the legacy infrastructure” or “utilize legacy infrastructure for new uses,"[82] projects will likely qualify, which will allow the Companies latitude in replacement siting to increase the operational value of the replacement assets and/or maximize tax credit adders.[83]

There are many examples of potential projects included in the program guidance, but some examples include replacing retired fossil fuel infrastructure with renewable energy, energy storage, distributed energy, or nuclear energy; providing transmission interconnections and upgrades for new clean energy facilities; and retrofitting fossil fuel-fired generators with CCS.

The LPO has indicated that it will consider applications that group together a portfolio of investments under a utilities' purview if each project can be tied back to either Category 1 or Category 2 eligibility.[84] Given that the purpose of the CPIRP is to plan for the achievement of the State's authorized carbon emission reduction requirement, a majority of the investments considered in this proceeding are likely to be eligible for EIR loan financing.

---

[82] Examples of legacy infrastructure include existing transmission, POIs, and land rights.

[83] *See* Title 17 Clean Energy Financing Part 1 Application Instructions, available at https://www.energy.gov/lpo/articles/title-17-clean-energy-financing-program-part-i-application-instructions.

[84] *See* Title 17 Program Guidance, at 53: "An applicant may submit a single application for multiple projects using different technologies or at different sites; however, LPO may require the applicant to separate such projects into multiple applications at any time during the application process."

Q. What does it mean to "repower" retired or qualifying energy infrastructure, and how can this program help achieve decarbonization goals?

A. Repowering refers to the process of retrofitting and modernizing existing power plants and installations.[85]

Utilizing existing fossil fuel infrastructure (such as transmission lines and interconnection facilities at retired coal or gas plants) by repowering them with renewable energy resources, referred to above as clean repowering, has the potential to expedite the deployment of a significant amount of new clean energy and reduce ratepayer bills.[86] Clean repowering can reduce lead times and costs to interconnect these new resources, and as an additional bonus, by utilizing retired fossil fuel infrastructure, these facilities may qualify for the IRA's Energy Community bonus adder, increasing the value of the production tax credits by 10% and investment tax credits by 10 percentage points. Clean repowering investments are also likely to be eligible for EIR loans. Therefore, the Public Staff recommends that the Commission require Duke to include all cost-effective clean

---

[85] The DOE LPO program guidance for EIR defines energy infrastructure as a facility and associated equipment used for: (1) the generation or transmission of electric energy; or (2) the production, processing, and delivery of fossil fuels, fuels derived from petroleum, or petrochemical feedstock. *See* Title 17 Program Guidance, at 26.

[86] *See* RMI report on clean repowering and the EIR, available at https://rmi.org/how-utility-regulators-can-unlock-12-7-billion-in-annual-savings-for-customers/

repowering projects in a Part 1 application for an EIR loan upon studying the clean repowering opportunity across its footprint.

Q. Why is it important for the EIR to be considered in the capacity expansion modeling that underlies the CPIRP?

A. The primary benefit of incorporating the EIR into CPIRP capacity expansion modeling is that it would assist in identifying a portfolio of resources that maximize the cost savings benefits that the EIR can offer. These benefits include lowering the costs of resources needed to comply with HB 951, and accelerating clean resource deployment by making certain resources economic earlier than they otherwise would have been. As described later in my testimony, the Public Staff's modeling of the EIR achieved both of these goals by reducing total portfolio costs while deploying incremental clean energy resources.

Because the EIR program has a limited application window, it is critical that the CPIRP modeling include the program so as to understand how the EIR impacts the CPIRP, and potentially identify a portfolio or projects that can be submitted for EIR loans. Given the program's 2026 conditional commitment deadline and 2031 in-service deadline, inclusion of the EIR in the CPIRP (and the resulting understanding of its impact on the NTAP) provides a baseline from which the Companies can investigate and pursue all economic investments to make use of these funds.

Q. Have the Companies included the EIR in their CPIRP modeling?

A. No.

Q. Did the Public Staff incorporate the EIR into its modeling?

A. Yes. In consultation with RMI and witness Boswell, the Public Staff's base case modeling included the assumption that Duke could finance up to 40% of the total cost of eligible projects placed in service by September 30, 2031.[87] The remaining portion of the capital stack was distributed proportionally based on the existing corporate debt to equity ratios. This allocation strategy ensured a comprehensive evaluation of the financing structure and its impact on overall costs. The Public Staff also ensured that the rate of return on corporate debt and equity remained unchanged. This financing scheme resulted in a slightly lower debt rate and a higher debt ratio, under the assumption that the EIR debt would be financed off-balance sheet, as recommended by witness Boswell. Eligible projects are defined as solar, battery storage, wind, and advanced nuclear.

---

[87] The Public Staff assumed that the rate of return for EIR debt was 37.5 basis points above long-term treasury yields. To estimate these yields, the Public Staff utilized the 30-year forward yield curve as of February 26, 2024, to assess the financial viability of clean energy projects.

Q. Did the Public Staff modeling capture all the impacts of the EIR?

A. No. The Public Staff's modeling did not account for several of the mechanisms through which the EIR can generate savings, including (1) the potential for transmission expansion plans, such as the second tranche of Red Zone Expansion Plan (RZEP 2.0) projects, to be considered eligible projects; (2) the potential for a higher-leverage EIR loan, as discussed in witness Boswell's testimony, which could yield higher savings than the approach described above; (3) the potential for clean repowering projects, which could represent cost-effective incremental resource additions relative to the amount of solar and storage selected by the model; and (4) the potential for EIR financing of environmental remediation costs associated with EIR projects, which could provide further savings for ratepayers.

The Public Staff's modeling also did not account for incremental costs associated with an EIR loan, including the costs of compliance with certain laws that are triggered when federal funds are utilized, such as the National Environmental Policy Act (NEPA), the Davis-Bacon Act, and the Cargo Preference Act. However, the Public Staff suspects that the costs of compliance will either scale at minimal cost (e.g., weekly payroll adjustments) or be outweighed by the benefits of a larger portfolio-wide EIR application. For these reasons, the Public Staff suspects that the cost savings of the base portfolio with the EIR financing parameters likely understate the total potential savings available to the Companies.

Q. What were the impacts of modeling the EIR financing parameters in the Public Staff's base portfolio?

A. The Public Staff ran its base portfolio with the EIR assumptions included, and then ran a sensitivity with the EIR assumptions removed. The base portfolio with EIR assumptions added an incremental 500 MW of eligible capacity through 2032, while simultaneously reducing the PVRR through 2032 by $96 million (0.3%) in DEC and $319 million (1.7%) in DEP. The EIR also incentivized the model to select solar plus storage over standalone solar, increasing the total capacity of battery storage on the system. This finding supports the Public Staff's belief that there are benefits of this program for ratepayers and that Duke should aggressively investigate and apply for EIR funding for CPIRP projects.

Q. Have the Companies investigated seeking EIR funding to lower costs for ratepayers?

A. While the Companies have not incorporated the EIR into the CPIRP, they **[BEGIN CONFIDENTIAL]** [redacted]

[redacted] **[END CONFIDENTIAL]**

Q. Does the Public Staff have any concerns with the Companies' approach?

A. Yes. As an initial matter, it is reasonable to evaluate whether the loans are a net benefit before the Companies submit applications given the increased project costs. Estimating these costs is a challenging task, but the Companies appear to be approaching the cost estimate in a reasonable manner.

However, as discussed in more detail in witness Boswell's testimony, the Public Staff is concerned that Duke may choose to only consider one option for its EIR cost benefit analysis: **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]** I reiterate witness

[88] *See* the testimony of witness Boswell for an explanation of how the Public Staff arrived at this conclusion.

Boswell's recommendation that the Commission direct the Companies to consider more expansive options for EIR funding, which may include financing a large portion of the project with EIR debt (the LPO has indicated up to 80% of project cost ratios can be financed with EIR debt[89]) and financing the remainder with corporate debt and equity at the Companies' approved capital structure. Duke should aggressively apply for any such funding that is cost-effective and pass those benefits to ratepayers as soon as possible.

I also recommend that the Companies be required to explain the results of their EIR cost benefit analysis, discuss whether any EIR applications have been submitted and whether they were accepted or denied, and explain the targeted financing structure in its next general rate case and the upcoming 2025 CPIRP.

Grid Edge

Q. What Grid Edge assumptions did the Public Staff make in its base portfolio?

A. Generally, the Public Staff utilized Duke's baseline estimate of the impact of Grid Edge programs (EE, DSM, behind-the-meter solar, critical peak pricing tariffs, and electric vehicles). Witnesses

[89] *See* Title 17 Program Guidance, at 9.

Williamson and Lawrence discuss Grid Edge in detail in their respective testimonies.

However, the Public Staff incorporated into its base portfolio the PowerPair pilot program,[90] with 30 MW of new solar plus storage capacity available in DEC and DEP from 2025 to 2028 (the capacity approved by the Commission for the pilot period of the program). In an attempt to determine whether this program would be a cost-effective way to add new solar and storage to the grid, the Public Staff modeled new distributed solar plus storage resources at a cost based on the approved incentive structure, with 40 MW available for selection in 2028 and beyond.[91] Nearly every portfolio and sensitivity analysis run by the Public Staff saw the model economically and consistently select this solar plus storage resource, despite the fact that the rooftop solar capacity factor is significantly lower than utility-scale.[92] While the details of any future PowerPair program expansions must be reviewed on an individual program basis, this modeling suggests that the framework of the PowerPair pilot can

[90] Approved in Docket Nos. E-7, Subs 1032 and 1261 and E-2, Subs 927 and 1287.

[91] This expanded availability in 2028 and beyond would represent a continuation of the approved residential program and an expansion of the program to commercial and industrial customers.

[92] The behind-the-meter solar assets modeled in the Public Staff's portfolios has a 17% capacity factor, compared to a 27% capacity factor for utility-scale solar.

reduce the costs of HB 951 compliance.[93] The Public Staff recommends that Duke develop and propose a program similar to PowerPair that is targeted towards non-residential customers, incorporating stakeholder feedback, as early as possible.

Q. Did the Public Staff test higher Grid Edge penetration?

A. Yes. The Public Staff ran several sensitivities that doubled the Companies' projected energy and capacity reductions for EE, existing DSM programs (except for integrated volt-var control and conservation voltage reduction), rooftop solar, and critical peak pricing tariff impacts. The cost estimates to administer these programs were also doubled to reflect increased participation. While witness Williamson discusses how these targets may not be achievable, the Public Staff wanted to understand the impact of Grid Edge programs on the CPIRP. This is particularly important in light of the pending revisions to the DSM/EE Mechanism[94] that were spurred, in part, by the Companies' 2022 Carbon Plan and the value of "shrinking the challenge."[95]

As seen in Table 11 below, the PVRR reduction associated with expanded Grid Edge participation is significant. Even though

[93] An updated cost-effectiveness test for the PowerPair program, filed on May 3, 2024, found that the program offered a cost benefit ratio of 1.67 in DEP and 1.83 in DEC.

[94] Docket Nos. E-2, Sub 931 and E-7, Sub 1032.

[95] *See* 2022 Carbon Plan Order, at 109-10.

doubling the participation and associated energy and capacity savings from these programs may not be possible, if the Companies are able to expand the impact of their portfolio of Grid Edge programs as a result of a revised DSM/EE Mechanism, the result could potentially reduce costs significantly for ratepayers.

Table 11: PVRR Comparisons with High Grid Edge

Interim Compliance Year	Public Staff Portfolio	PVRR through 2038 ($B)	PVRR through 2050 ($B)
2030	No CC	$91.6	$173.3
	No CC, High Grid Edge	$84.6	$156.0
	High Grid Edge Savings	**$6.9**	**$17.4**
2032	Base	$92.3	$169.8
	High Grid Edge	$86.2	$157.6
	High Grid Edge Savings	**$6.1**	**$12.2**

Q. Do you have any other recommendations regarding the Companies' modeling of Grid Edge?

A. The cost savings associated with increased Grid Edge programs suggests that these programs are a critical component of the least-cost pathway. However, as discussed in witness Williamson's testimony, the growth of DSM programs in DEC appears to slow significantly in the late 2020s, particularly when compared to the growth of other Grid Edge programs and DSM in DEP. This may be a function of how the Companies model DSM programs in EnCompass – only Commission-approved programs and their forecasted adoption rates are included in the model.

However, there is a universe of new or expanded DSM programs that Duke may be developing or planning at any given time, particularly given the recent proposed changes to the DSM/EE Mechanism. Including these underdevelopment programs in the EnCompass model as selectable DSM resources, either in a base portfolio or a sensitivity analysis, could offer the Company insight into the benefits such programs could provide and the scale at which they need to be deployed in order to be successful and may provide information valuable to DSM program development. I recommend that the Commission direct Duke to consider incorporating new DSM programs in future CPIRP cycles that can be economically selected by the EnCompass model.

Full Hydrogen Conversion

Q. Did the Public Staff allow natural gas units to rely on 100% hydrogen blending, as Duke did?

A. No. Witness Michna explains in his testimony that an assumption of late 2040s conversion of existing and future natural gas units to run on 100% hydrogen is premature and recommends that it be removed from the Public Staff's portfolio. While the 100% hydrogen conversion was removed, the Public Staff allowed low levels of hydrogen blending in the natural gas supply (1% by volume in 2035, 2% by 2038, and 3% by 2041), consistent with Duke's assumptions.

While this modification does not necessarily impact the NTAP, it does result in the Public Staff's models building significantly more solar, storage, nuclear, and offshore wind in the 2042 to 2050 period in order to achieve carbon neutrality, as shown in Table 12 below.

However, it should be noted that this difference in late-term resource additions between P3 Fall Base and PS Base 2034 is likely due to Duke's assumption that all the hydrogen necessary to operate its natural gas fleet with 100% hydrogen comes from low-carbon hydrogen production and is transported into the Companies' territories. As discussed in the testimonies of witnesses Nader and Michna, if local hydrogen production is necessary, the additional load required to produce it, coupled with low-carbon production requirements, would likely result in the need for significant additions of new renewable resources, greater than the buildout in the last eight years of the Public Staff's base portfolio shown below.

Table 12: Resource additions in the 2040s

Resource Deployments (2042 - 2050)	**P3 Fall Base**	**PS Base 2034**	**Delta**
Nuclear	6,750	7,800	1,050
Solar (Solar and SPS)	6,300	13,725	7,425
Batteries (Standalone and SPS)	5,620	11,640	6,020
Onshore Wind	0	0	0
Offshore Wind	4,000	0	(4,000)
Natural Gas CT	850	0	(850)
Total Interconnections (MW)	**23,520**	**33,165**	**9,645**

While the Public Staff is not dismissing hydrogen outright, removing it from the model results in higher levels of resource deployment in the out years of the planning horizon and lower utilization rates of existing and new natural gas assets, as discussed by witnesses Michna and Metz.

Offshore Wind

Q. What changes did the Public Staff make to offshore wind assumptions in its base portfolio?

A. Based on the testimony of witness Lawrence, the Public Staff modified Duke's representation of offshore wind by creating five mutually exclusive blocks of offshore wind that range from 1.1 GW to 5.5 GW; for all projects, only 1.1 GW was allowed to come online in any given year, beginning with the first block in 2031. As described in witness Lawrence's testimony, this approximately represents the four available WEAs[96] off the coast of North Carolina, assuming for the sake of modeling that Duke could procure none, some, or all of the sites.[97] Witness Lawrence also provided adjusted capital costs and transmission upgrade costs associated with each block of

[96] The four available WEAs are Kitty Hawk North and Kitty Hawk South (owned by Avangrid Renewables, LLC); Carolina Long Bay East (owned by Cinergy Corp., a Duke Energy affiliate); and Carolina Long Bay West (owned by TotalEnergies).

[97] The model does not use any of the highly confidential offshore wind RFI results provided to the Public Staff in discovery.

offshore wind. Transmission interconnection and upgrade costs ranged from **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**.

Q. You also raised an issue regarding how offshore wind ELCC values were incorporated into EnCompass. Please expand on this.

A. In Attachments II and III to its CPIRP, Duke presented marginal capacity values for offshore wind in the winter season. Attachment II provided that the first block of wind had a marginal capacity value of 69.7%.[98] In Attachment III, offshore wind in DEP had a marginal capacity value of nearly 75% (for the first tranches), falling to approximately 60% as additional tranches were added (shown in Figure 4).[99] However, in EnCompass, Duke modeled its offshore wind resources with an ELCC value of **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

In modeling the Public Staff's offshore wind tranches, new capacity

---

[98] *See* Attachment II, Table 13.

[99] *See* Attachment II, Table 3.

values for the Public Staff's offshore wind blocks were calculated utilizing the findings from Attachment III to create a declining ELCC curve, correctly representing the capacity value of offshore wind.

Q. When offshore wind was modeled in this way, what were the results?

A. Most Public Staff portfolios selected between 1.1 and 4.4 GW of offshore wind, with PS Base 2034 selecting 4.4 GW. The timing and quantity of offshore wind was highly dependent on how quickly nuclear could come online. For example, in the accelerated nuclear sensitivity, when SMRs can be brought online in 2033, the model selects only 1.1 GW of offshore wind and delays its selection until 2038. The Public Staff also ran sensitivities that limited offshore wind to only 2.2 GW while delaying to 2033 and 2035, more in line with Duke's assumptions. This model replaced the removed offshore wind with more solar and storage, and a sixth CC in 2034.

Q. What conclusions can you draw regarding offshore wind?

A. Based on the results of both Duke's and the Public Staff's modeling, offshore wind has an important role to play in the energy transition. Offshore wind can help serve as a hedge against delays in the deployment of new nuclear. Likewise, early nuclear deployment could reduce the amount of offshore wind that is necessary to comply with HB 951. The Public Staff believes that Duke should continue to pursue offshore wind by expeditiously taking steps to engage with the three WEA lease holders.[100]

Natural Gas

Q. Please summarize the changes related to natural gas assumptions that the Public Staff made to the CPIRP in its Base portfolio.

A. As discussed in witness Michna's testimony, during its investigation the Public Staff noted that Duke had allowed its portfolios to select a CC in DEP as early as 2029, while DEC was not permitted to add a CC until 2031. Because of the need for energy and capacity in this critical period, this decision effectively forced the model to select the first two CCs in DEP's territory, despite the increasing power flows from DEP to DEC, as identified by witness Metz. The Public Staff ran a sensitivity where this constraint was removed, and almost all model runs selected all CCs, or nearly all, in DEC's territory (where most of the load growth is occurring). Any future CPCN applications for CCs in DEP's territory will need to be closely examined to ensure that the constraints Duke forced upon the model are not being relied upon to justify locating a CC in DEP.

[100] *See* the Public Staff's April 17, 2024 Motion Requesting Issuance of Commission Order.

The Public Staff also performed modeling that limited the number of available CCs to four, and another that imposed a high gas commodity sensitivity, the conclusions of which are discussed below. These natural gas sensitivities are designed to capture some of the uncertainty facing the future use of fossil fuels; however, they do not necessarily quantify the risk of these resources becoming stranded at a future date.

Q. Did the Public Staff model the EPA's recently finalized Clean Air Act rules?

A. Yes. As discussed in witness Nader's testimony, the EPA finalized its new rules under Sections 111(b) and 111(d) of the Clean Air Act on April 24, 2024, in a prepublication version that will be published in the federal register at a future date.[101] The final rules removed hydrogen blending as a best system of emission reduction, instead relying on CCS for new baseload natural gas plants that operate at a greater than 40% annual capacity factor.

Based on the recommendations of witness Nader, I attempted to incorporate the EPA's new Clean Air Act rules by limiting all new natural gas CCs and CTs to no greater than a 40% annual capacity

[101] *See* https://www.epa.gov/system/files/documents/2024-04/eo-12866_111egu_2060-av09_nfrm_20240424_final.pdf.

factor.[102] This limitation would exempt these units from the CCS requirement, which some research has concluded would be "economically infeasible" in North Carolina due to the unsuitability of the state for geologic sequestration; compliance with any CCS requirement would likely require a new pipeline to transport CO_2 to an appropriate reservoir.[103] While Duke has been engaged with researchers and other utilities to explore carbon sequestration in southeastern South Carolina,[104] at this time the Public Staff did not attempt to model CCS in its EPA sensitivity.

Q. Can hydrogen blending still be used to comply with the recently finalized Clean Air Act rules?

A. Possibly. As discussed in witness Nader's testimony, much will depend upon how the North Carolina Department of Environmental Quality (DEQ) crafts its state implementation plan to comply with the EPA rules, and whether the EPA rules for new natural gas plants are

---

[102] Generally, all other modeling assumptions used in the EPA sensitivities were kept the same as in PS Base 2034. However, the Public Staff modeled one EPA sensitivity with accelerated nuclear and another with delayed offshore wind, as discussed in witness Metz's testimony.

[103] Williams, E.; Greenglass, N.; Ryals, R. (2007). *Carbon Capture, Pipeline and Storage: A Viable Option for North Carolina Utilities?* Nicholas Institute for Environmental Policy Solutions and The Center on Global Change, Duke University. CCPP WP 07-01. Available at https://nicholasinstitute.duke.edu/sites/default/files/publications/carbon-capture-pipeline-and-storage-a-viable-option-for-north-carolina-paper.pdf.

[104] *See* the Final Report on Potential Sinks for Geologic Storage of Carbon Dioxide Generated by Power Plants in North and South Carolina, attached as Thomas Exhibit 1.

immediately effective or implemented through a state plan.[105] However, modeling new natural gas plants as operable on high levels of hydrogen blending by 2032 (the year the CCS requirements phase in for baseload natural gas plants), at levels sufficient to meet the finalized CAA rules, would require the inclusion of significant new load to produce, transport, and store this hydrogen, as discussed in witness Michna's testimony. In addition, to qualify for the clean energy tax credits associated with hydrogen production, the hydrogen would need to be produced by incremental clean energy located in the same region as the hydrogen production.

Q. What conclusions can you draw from the natural gas sensitivities?

A. Given the unique circumstances in North Carolina – large economic development occurring over a relatively short time period and delays in procuring new nuclear and wind resources until the mid-2030s – the model still economically selects natural gas CCs under all four gas sensitivities, as shown in Table 13 below. However, in both 2034 EPA sensitivities where the Public Staff's base assumptions of resource availability were used, including offshore wind in service by 2031, the model only economically selected three CCs, instead

[105] States have approximately two years from the date of the final rule to submit their own state plans to the EPA, but the state plans may only be required for existing steam generators, with the standards for new natural gas generators becoming effective without a state plan.

relying on existing natural gas units, solar, storage, and either offshore wind or nuclear. Despite this selection of CCs in the EPA sensitivities, there exists the potential for significant unanticipated environmental compliance costs related to CCS or hydrogen blending across all portfolios, should it not be possible to maintain the 40% capacity factor limit on new CCs or to accelerate nuclear as envisioned in the Public Staff's EPA runs.

Table 13: Natural gas sensitivity resource selections (MW)

Resource Deployments (2028 - 2034)	2034 - Four CCs	2034 - High Gas Price	2034 - EPA 2035 SMR	2034 - EPA 2032 SMR
Nuclear	0	0	0	2,400
Solar (Solar and SPS)	13,500	13,650	15,825	15,225
Batteries (Standalone and SPS)	7,160	6,020	7,740	5,420
Onshore Wind	2,250	2,250	2,250	2,250
Offshore Wind	4,400	4,400	4,400	0
Natural Gas CC	5,436	6,796	4,077	4,077
Natural Gas CT	1,270	1,270	1,695	1,695
Total Interconnections (MW)	**34,017**	**34,386**	**35,988**	**31,068**

Q. Did the Public Staff test any other scenarios regarding the EPA rules?

A. Yes. In order to test more conservative interconnection assumptions and their interplay with the EPA rules, we ran an EPA scenario based upon the PS Base 2034 portfolio, but with solar and energy storage interconnection limits similar to Duke's P3 Fall Base, with offshore wind delayed to 2035. However, the model could not meet the carbon emission limits associated with a 2034 interim compliance date while limiting new CCs to a 40% capacity factor. We then ran the same scenario with a 2037 interim compliance date, which the model was able to solve with minimal (less than 1%) carbon exceedances.

In order to achieve the 2037 interim compliance date under the EPA rules, the model also accelerated CC deployment, significantly increased CT deployment, and selected less offshore wind, as described in witness Metz's testimony. While the Public Staff's modeling of the finalized EPA rules only explored one potential option (reducing the capacity factor of new CCs to avoid CCS requirements), complying with the EPA rules in this way may end up increasing costs and requiring more natural gas resources, not less.

Load Forecast

Q. Did the Public Staff model alternative load forecasts?

A. Yes, although the Public Staff's base portfolio relies upon the Companies' SPA load forecast. Based on the Load Forecast Panel's testimony, I modeled an adjusted load forecast as a sensitivity. This adjusted load forecast attempts to account for "double counting" in Duke's economic load projections for large load customers, as described in the Load Forecast Panel's testimony.

Q. At a high level, what were the results of the adjusted load forecast sensitivity?

A. The only significant impacts of the adjusted load sensitivity on near-term resource needs (in service by 2034) are related to batteries, CTs, and offshore wind, as shown in Table 14. The adjusted load scenario selects 460 MW more battery capacity, 850 MW less CT capacity, and only 1.1 GW of offshore wind in 2034, rather than the 4.4 GW selected in 2031 in the Public Staff's base portfolio. This suggests that offshore wind would be one of the first resources to be delayed or reduced if the load forecast is lower than anticipated. The adjusted load forecast does not appear to impact CC deployment.

Table 14: Resource Deployment Changes in the Adjusted Load Forecast Sensitivity

Resource Deployments (2028 - 2034)	PS - 2034 - Base Load	PS - 2034 - Adjusted Load	Delta
Nuclear	0	0	0
Solar (Solar and SPS)	13,500	13,500	0
Batteries (Standalone and SPS)	5,700	6,160	460
Onshore Wind	2,250	2,250	0
Offshore Wind	4,400	1,100	(3,300)
Natural Gas CC	6,796	6,796	0
Natural Gas CT	1,270	421	(850)
Total Interconnections (MW)	**33,916**	**30,226**	**(3,690)**

Public Staff Portfolio Costs

Q. Did the Public Staff calculate the PVRR of its portfolios?

A. Yes. The Public Staff utilized the PVRR workpapers provided by the Companies to estimate the PVRR for its own portfolios on a consistent basis. A selection of PVRR estimates through 2038 and 2050 is shown in Table 15 below. The findings suggest that there is a relatively narrow band of PVRR across these sensitivities, particularly within the same interim compliance year. Earlier interim compliance does have a cost, although the Public Staff's modeling suggests that if certain resource procurement targets are met, 2034 compliance may not be significantly more expensive than 2035 compliance (e.g., P3 Fall Base has a 2050 PVRR of $149 billion, compared to the Public Staff's 2034 Base estimate of $150.8 billion). However, near-term PVRR estimates do have more variation. Interestingly, the Public Staff's 2035 interim compliance scenario had a lower PVRR in 2038, but nearly the same PVRR in 2050. While the 2035 portfolio had lower capital costs, these savings were nearly outweighed by higher production costs (i.e., fuel and operations).

Table 15: PVRR of select Public Staff portfolios and sensitivities

Portfolio	PVRR through 2038 ($B)	PVRR through 2050 ($B)
P3 - Fall Base (Duke Recommended Portfolio)	$77.9	$149.0
PS - 2030 Base	$88.4	$167.3
PS - 2032 Base	$92.3	$169.8
PS - 2034 Base	$80.9	$150.8
PS - 2034 - No EIR	$81.2	$151.1
PS - 2034 - Accelerated SMR	$76.1	$148.1
PS - 2034 - Limited Offshore Wind	$79.9	$153.0
PS - 2035 Base	$77.8	$149.8

V. PUBLIC STAFF RECOMMENDATIONS

Q. Are you making any recommendations to the Commission?

A. Yes. My testimony makes the following recommendations for the 2023 CPIRP:

1. That the Commission approve a CPIRP and near-term action plan that targets an interim compliance date of no later than 2034.

2. That the Commission find reasonable Duke's proposed development costs of $165 million for the Bad Creek II facility.

3. That the Commission direct Duke to (1) update the estimated Bad Creek II costs in the next CPIRP, and (2) notify the Commission and discuss the economics of Bad Creek II if the costs increase by more than 15%.

4. That the Commission direct Duke to convene a stakeholder process with solar and storage developers for the 2025 competitive procurement to design a competitive procurement and pro forma PPA targeted towards smaller, distribution-connected projects, specifically operational QFs with expiring PPAs.

5. That the Commission direct Duke to study the interconnection of solar and battery storage resources across its footprint of fossil generators, and particularly at existing CT sites, as soon as possible, and to include these opportunities in its near-term procurement efforts in order to reduce costs and development timelines.

6. That the Commission require Duke to include all cost-effective clean repowering projects in a Part 1 application for an EIR loan upon completion of studying the clean repowering opportunity across its footprint.

7. That the Commission direct Duke to consider the full range of EIR benefits in its analysis of the costs and benefits of EIR funding, and direct Duke to aggressively apply for any such funding that is cost-effective.

8. That the Commission direct Duke to explain the results of its EIR cost benefit analysis prior to submission of an EIR Part 1 application so that the Commission can be assured of the appropriateness of the Companies' evaluation methodology.

9. That the Commission direct the Companies to (1) subsequently report any EIR applications submitted and whether they were accepted or denied, and (2) provide an explanation of the targeted financing structure in its next general rate case and the 2025 CPIRP.

10. That the Commission direct Duke to develop and propose a program similar to PowerPair that is targeted towards non-residential customers, incorporating stakeholder feedback as early as possible.

11. That the Commission direct Duke to consider incorporating new DSM programs in future CPIRP cycles that can be economically selected by the EnCompass model.

Q. Does this conclude your testimony?

A. Yes.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JEFF THOMAS

I graduated from the University of Illinois Champaign-Urbana in 2009, earning a Bachelor of Science in General Engineering. From 2009 to 2015, I worked in various manufacturing operations management roles with General Electric and United Technologies. I left in 2015 to attend North Carolina State University, earning a Master of Science degree in Environmental Engineering in 2017. My master's thesis focused on electric power system modeling, capacity expansion planning, linear programming optimization, and the effect of various state and national energy policies on North Carolina's generation portfolio and electricity costs. After obtaining my degree, I joined the Public Staff in November 2017. In my current role, I have investigated and filed testimony in avoided cost determinations, general rate cases and riders, interconnection queue reform, CPCN applications, and integrated resource planning proceedings. I have also worked on the implementation of HB 589 renewable energy programs, including the development of the Competitive Procurement of Renewable Energy program. I have also worked on the initiation and implementation of HB 951 provisions, such as the Carbon Plan, voluntary renewable energy purchase programs, and performance based ratemaking. I received my Professional Engineering license in North Carolina in April 2020.

Southeast Regional Carbon Sequestration Partnership

Report Type: Documentation of completion
Report number : Phase III Milestone 1.2.c
Report title: Improved capacity update in the South Carolina-Florida area"

Completion Date: March, 2008

Report Issue Date: September 25, 2008

DOE Award Number: DE-FC26-05NT42590

Submitting Organization: Susan D. Hovorka, Principle Investigator,
Gulf Coast Carbon Center
Bureau of Economic Geology
Jackson School of Geosciences
The University of Texas at Austin

Comments: This data has been submitted to MIT for inclusion in NATCARB II Atlas and submitted to the sponsors who provided funding to accelerate and improve the data for this area: Duke Energy, Progress Energy, Santee Cooper Power, SCANA Corporation

Final Report

Potential Sinks for Geologic Storage of Carbon Dioxide Generated by Power Plants in North and South Carolina

by
Rebecca C. Smyth, Susan D. Hovorka, Timothy Meckel,
Caroline Breton, Jeffrey G. Paine, Gerald R. Hill,
Howard Herzog, Hongliang (Henry) Zhang, and Weifeng Li

with assistance from
Paul Thayer, University of North Carolina at Wilmington
Tom Temples, University of South Carolina at Columbia

prepared for
Southern States Energy Board
Electric Power Research Institute

on behalf of
Duke Energy
Progress Energy
Santee Cooper Power
SCANA Corporation

Gulf Coast Carbon Center
Bureau of Economic Geology
Scott W. Tinker, Director
Jackson School of Geosciences
The University of Texas at Austin

March 2008

Preface from power company representatives:

A consortium of four power companies in the Carolinas (Duke Energy, Progress Energy, Santee Cooper Power, and South Carolina Electric and Gas) has funded this project in cooperation with the Electric Power Research Institute (EPRI) and the Southern States Energy Board (SSEB) to take an active role in finding solutions to climate change issues. This is our first step on the path toward understanding the opportunities and constraints of carbon storage. Our motivation is to seek information that will enable application of this technology.

This document summarizes a scoping study of the current state of knowledge of carbon storage options for our geographic area. The focus is on one aspect of carbon capture and storage— identification of deep saline reservoirs in which carbon dioxide (CO_2) generated in the Carolinas might be stored. The study does not address other aspects of CO_2 storage projects, such as capture and compression of the gas, well construction and development, or injection. Transport of CO_2 is touched upon in this study but has not been fully addressed.

The information contained in this document is primarily from review of published geologic literature and unpublished data. No field data collection has been completed as part of this study. Further work will be necessary to increase confidence in the suitability of the potential CO_2 storage sites identified in this report. This study does not address the regulatory, environmental, or public policy issues associated with carbon storage, which are under development at this time.

Table of Contents

List of Appendices

Appendix A. Thayer and Temples contract reports
Appendix B. ARI report on Mt. Simon
Appendix C. MIT Capacity and Pipeline Cost Estimate documents – March 2006
Appendix D. MIT Pipeline Cost Estimate document – October 2006

List of Tables

List of Figures

Executive Summary

Introduction

Options for reduction of atmospheric emissions of greenhouse gases (GHG) are currently under consideration by both government (Federal and State) and industry, and interest will continue to expand (e.g., Herzog, 2001; DOE, 2005; Hoffman, 2006). Carbon dioxide (CO_2) occurs naturally in the atmosphere, but over the past few centuries concentrations have increased as a result of emissions from anthropogenic sources. At this time CO_2 emissions are not regulated in the U.S.; however, discussions on reducing the intensity of GHG emissions are under way. Technologies to separate, capture, and concentrate CO_2 from industrial emissions are under development but are not yet ready for commercial use.

Geologic storage is a process whereby concentrated CO_2, captured from industrial sources, will be injected into suitable subsurface strata or geologic "sinks" and stored for significant periods of time (thousands of years) through physical or chemical trapping (Bachu et al., 1994). The combination of carbon capture and storage is known by the acronym CCS. According to a recently released report by researchers at Massachusetts Institute of Technology (MIT) (Deutch et al., 2007), "CCS is the critically enabling technology to help reduce CO_2 emissions significantly while also allowing coal to meet the world's pressing energy needs."

The study summarized here updates and supersedes previous CO_2 source-sink matching analyses (Hovorka et al., 2000) used in Phase I of the Southeast Regional Carbon Sequestration Partnership (SECARB), which was funded by the Department of Energy (DOE) through the Southern States Energy Board (SSEB). Funding for this study is from Carolinas power companies Duke Energy, Progress Energy, Santee Cooper Power, and South Carolina Electric and Gas, in cooperation with the Electric Power Research Institute (EPRI) and SSEB. A goal of the study is to increase understanding of the technical feasibility of subsurface geologic storage of CO_2 in order that informed decisions may be made regarding GHG issues in the region.

The focus here is to identify geologic units containing deep saline reservoirs, or sinks, that might be suitable for effective, large-volume geologic storage of CO_2 generated by power plants in North and South Carolina. All data used to evaluate the suitability of the potential geologic sinks are from preexisting geologic studies, the majority from published literature. Geologic units underlying most of North and South Carolina do not meet minimum suitability criteria necessary for long-term storage of CO_2. Hence, in order to match potential sources of CO_2 with potential sinks, a process known as *source-sink matching*, CO_2 will have to be transported before it can be injected into the subsurface and isolated from the atmosphere and freshwater resources.

Evaluation of the constraints to transport CO_2 generated in the Carolinas, including pipeline costs, was conducted by the MIT Laboratory for Energy and the Environment in late 2006. The pipeline cost estimates (in 2006 dollar equivalents for materials) include neither the cost of capture/separation at the plant nor cost of compression or injection at the CO_2 storage site, which are beyond the scope of this assessment. In recent work to evaluate costs of CCS, MIT researchers (Deutch et al., 2007) estimated that the cost of CO_2 capture and pressurization will greatly exceed the cost of CO_2 transportation and storage.

Background

Minimum suitability criteria for geologic sinks include (1) continuity and integrity of an overlying seal; (2) depth sufficient to maintain CO_2 at high density (which corresponds to depths greater than 800 m (>2,400 ft) below the surface); (3) depth below underground sources of drinking water (USDW), where total dissolved solids exceed 10,000 parts per million (ppm); and (4) storage capacity sufficient to prevent displacement of saline water into overlying freshwater-bearing units.

Estimates of the capacity of potential geologic sinks presented in this report have been provided by coworkers at Massachusetts Institute of Technology (MIT). The MIT methodology assumes that if requirements 1 and 2 above are satisfied, the CO_2 storage capacity of a saline reservoir can be calculated using the following formula:

$$Q_{aqui} = V_{aqui} * p * e * \rho_{CO2} \qquad (1)$$

where Q_{aqui} = storage capacity of entire reservoir (Mt CO_2)

V_{aqui} = total volume of entire reservoir (km^3)

p = reservoir porosity (%)

e = CO_2 storage efficiency (%)

ρCO_2 = CO_2 density at reservoir conditions (kg/m^3)

If accurate spatial data are available for a reservoir, then the reservoir volume used in equation 1 can be calculated as an integral of the surface area and thickness of the reservoir:

$$V_{aqui} = \sum_i S_i T_i \qquad (2)$$

where S_i is the area of the raster cell and

T_i is the thickness of the cell

The term "CO_2 storage efficiency" refers to the fraction of the reservoir pore volume that can be filled with CO_2. For a saline reservoir in which CO_2 can be trapped by a physical barrier (overlying seal), the storage efficiency is estimated at 2% (Holloway, 1996).

Large areas of the southeastern U.S. either are unsuitable or have low potential for geologic storage of CO_2 (figure ES-1). This suitability is related to geologic processes that have formed the present-day substrate of the southeastern U.S. over millions of years. A schematic cross section depicting the subsurface of the southeastern U.S. is shown in figure ES-2. Western portions of the Carolinas are underlain by highly fractured crystalline (igneous and metamorphic) rocks of the Blue Ridge and Piedmont physiographic provinces of the Appalachian Mountains (figs. ES-1, ES-2). Fractured crystalline rocks can serve as limited-capacity fluid reservoirs but are unsuitable for large-volume CO_2 storage if they lack laterally extensive overlying sedimentary seals. Rocks in the Blue Ridge and Piedmont provinces lack suitable seals throughout the Central and Southern Appalachian Mountains.

Exposed Mesozoic-age rift basins within the Piedmont province (fig. ES-1) might be considered for CO_2 storage on a site-specific basis. However, they do not meet the minimum suitability criteria used in this study. Rocks in the Valley and Ridge province have low potential for geologic storage because they are extensively folded and faulted. Limited capacity sinks are likely present in isolated areas beneath the Valley and Ridge province (fig. ES-1), but drilling and testing will be required to document storage integrity at specific locations.

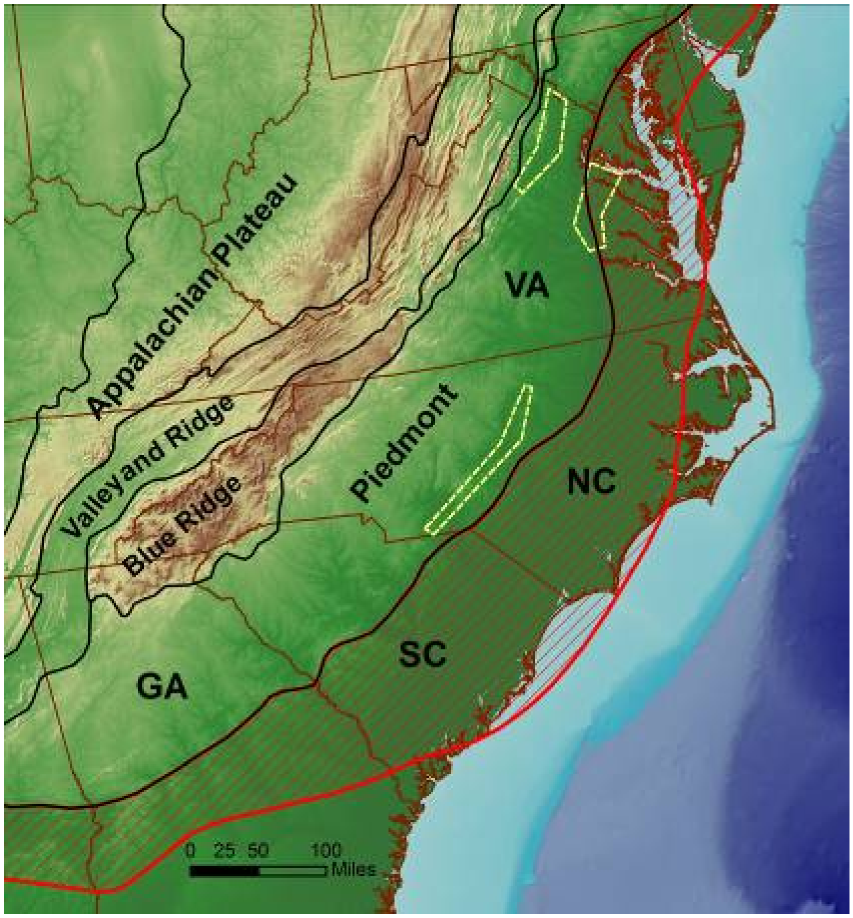


Figure ES-1. Physiographic provinces of the Appalachian Mountains and portions of the Coastal Plain where sediments are less than 800 m thick (outlined in red). Sources: Physiographic provinces of Appalachian Mountains modified from Fenneman and Johnson (1946); exposed Mesozoic rift basins (dashed yellow lines) modified from Olsen et al. (1991); and digital elevation models from NOAA (2006) (land) and Scripps (2006) (ocean floor). Depth to seafloor increases with darker shades of blue. Elevation of land surface increases from green to yellow to brown.

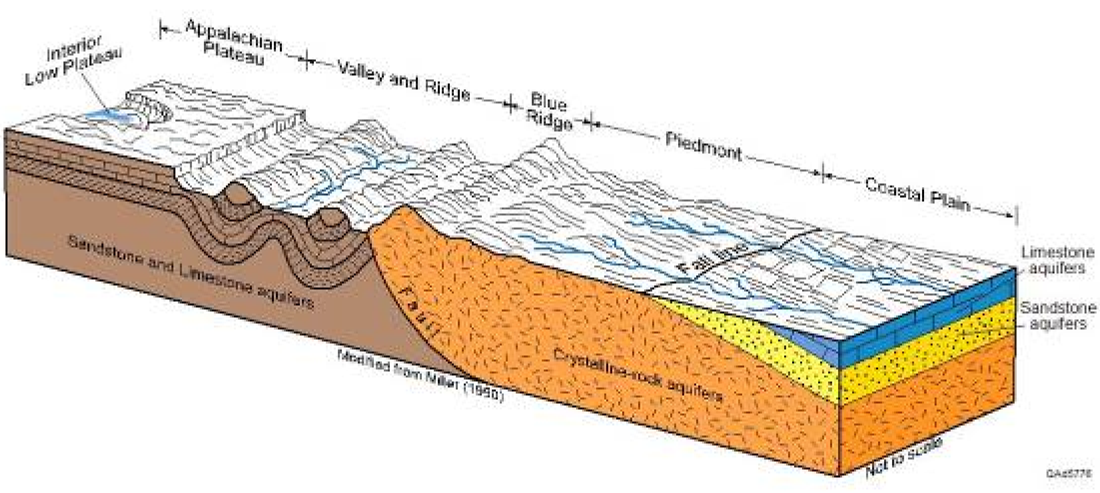


Figure ES-2. Schematic cross section from NW Alabama to south Georgia Coastal Plain.

Data compiled for this study show that much of the Coastal Plain province of the Carolinas is underlain by sedimentary sequences too thin for emplacement of CO_2 at sufficient pressure or at depths far enough below freshwater resources (figs. ES-1, ES-2). Sedimentary rocks within the area outlined in red in figure ES-1 are less than 800 m (<2,400 ft) thick, and they are underlain by Piedmont crystalline rocks (fig. ES-2). Because the coastal-plain sediments are saturated with relatively fresh groundwater, injection of CO_2 would not be possible under the criteria of this study.

Potential Sinks

Prospective geologic sinks (i.e., those subsurface units that *do* meet minimum suitability criteria) underlie areas located in (1) isolated basins along Atlantic coastlines of North Carolina, South Carolina, and Georgia (Hatteras and South Georgia Basin [SGB] sinks); (2) offshore ~1 km below the Atlantic seafloor (Unit 90 and Unit 120 sinks); and (3) nearby states (Tuscaloosa, Mt. Simon, and Knox sinks) (fig. ES-3).

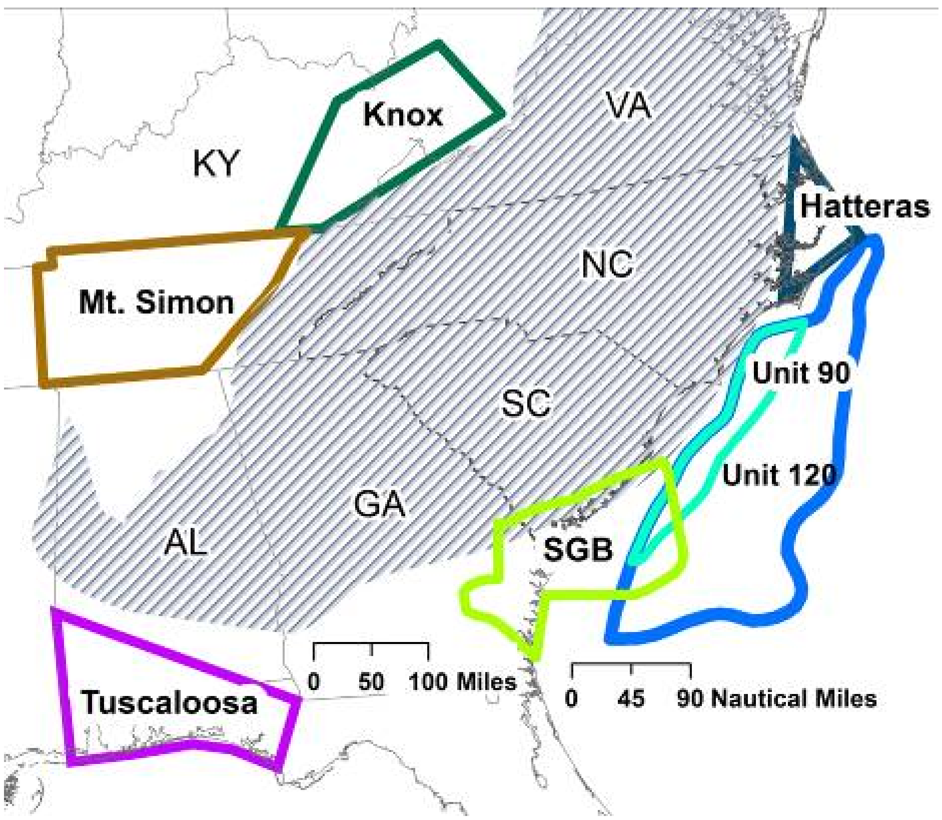


Figure ES-3. Location of low-potential regions (stippled area) and high-potential geologic sinks. SGB = Cretaceous- and Triassic-age geologic units in South Georgia Basin.

Sinks with potential for long-term storage of CO_2 generated in the Carolinas are all deep saline reservoirs within host geologic strata. All sinks presented here have been chosen through study of existing and, in most cases, published data. Additional field-data collection and verification will be required to test the suitability of specific injection sites and refine the generalized capacity estimates presented herein. This initial assessment of geologic sinks with potential for long-term storage of CO_2 is unencumbered. That is, it is based solely on the suitability of subsurface units to store CO_2; it does not take into account environmental, economic, or socio/political issues that will need to be balanced with geologic suitability.

Potential sinks within the Carolinas are Hatteras and SGB (fig. ES-3). Sediments west of Cape Hatteras attain a thickness of 2.7 km (1.7 mi) (fig. ES-4), which is sufficient to contain potential CO_2 sinks. However, literature review to obtain hydraulic properties and other data needed to estimate capacity of specific stratigraphic units was not performed for this study.

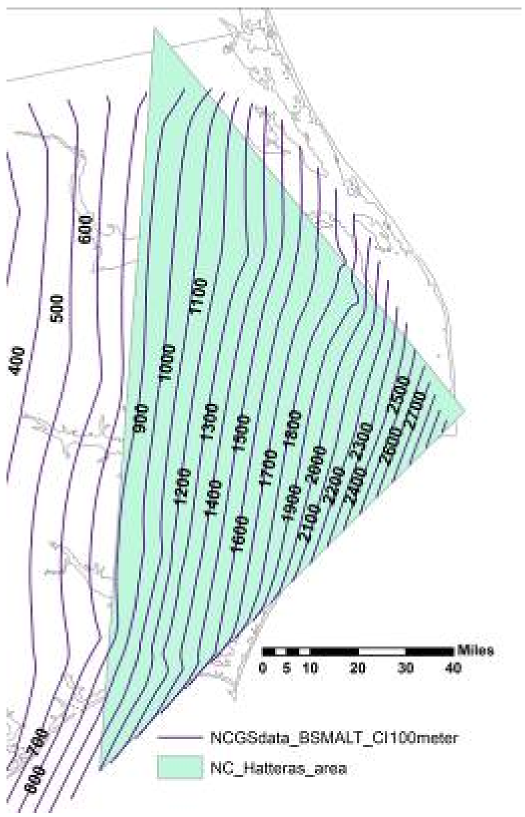


Figure ES-4. Depth (m) to crystalline basement rocks in the Hatteras area. Contours generated from North Carolina Geological Survey well data provided by Dr. Paul Thayer.

The South Georgia Basin is the east end of a series of structural basins spanning from Alabama across south-central Georgia, southern South Carolina, and eastward onto the Atlantic continental shelf. Through previous work associated with SECARB, and what is reported herein, we have identified three potential sinks in the South Georgia Basin: (1) Late Cretaceous-age Cape Fear Formation from previous SECARB work, (2) Late Cretaceous-age Tuscaloosa/Atkinson units in Georgia, and (3) Triassic-age units that are buried beneath coastal-plain sediments and extend offshore from South Carolina and Georgia (fig. ES-5). These three potential sinks partly overlap in map view but span different depth horizons between 800 and 1,300 m (2,600 and 4,300 ft); they are represented as one geologic sink, SGB, in figure ES-3. The combined estimate of capacity for these three contiguous, vertically stacked sinks is approximately 15 gigatons (Gt).

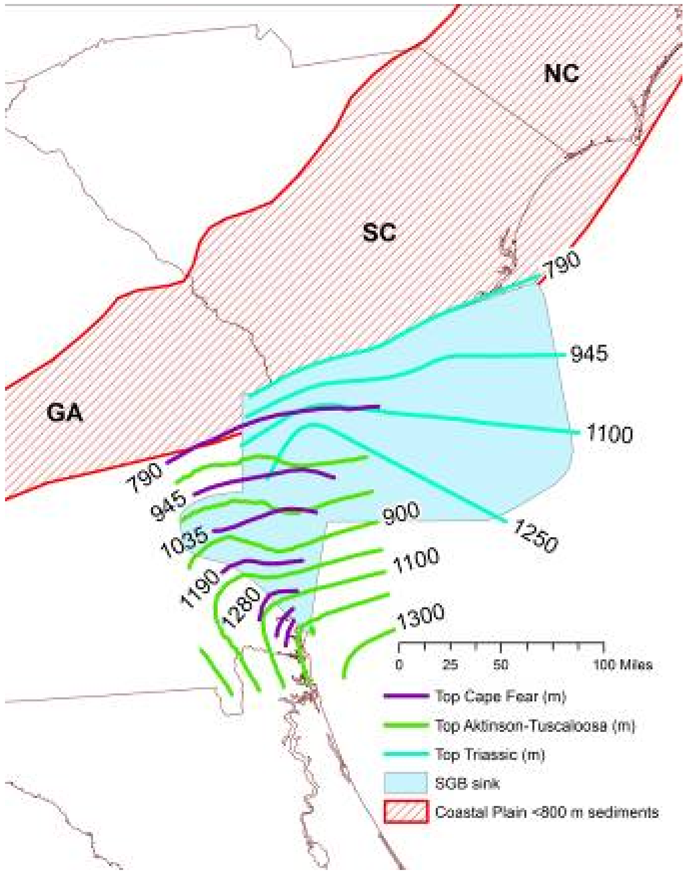


Figure ES-5. Three geologic sinks within the South Georgia Basin. Modified from Hovorka et al. (2000), Temples (pers. comm., 2006), Gohn et al. (1980), and Renkin et al. (1989).

Two potential CO_2 sinks are present in geologic strata below the Atlantic seafloor, offshore from Cape Hatteras, North Carolina, to Brunswick, Georgia (units 90 and 120 on fig. ES-3). Offshore settings involve initially higher pressures (beneath the water column) and lower temperatures at the seafloor, both of which favor denser CO_2 phases throughout subseafloor storage depths when compared with terrestrial settings. It is important to note that potential offshore activities involve injections at thousands of meters below the seafloor and should not be misinterpreted to include injection (dissolution) into circulating seawater.

The subseafloor sinks are located between 25 and 175 km offshore from the Carolinas in Upper (unit 90) and Lower (unit 120) Cretaceous strata between approximately 500 and 3,000 m (1,650 and 9,850 ft) beneath the seafloor in water depths between 50 and 1,000 m (165 and 3,280 ft) (figs. ES-3, ES-6). Both of these potential sinks are overlain by low-permeability seal layers, the shallowest of which lies between 200 m (660 ft) (landward) and 2,000 m (6,600 ft) seaward below the seafloor (Hutchinson et al., 1996, 1997). Lack of extensive drilling in the Atlantic offshore from the Carolinas means that seal integrity should be excellent, but results in few available hydraulic property data. Using core data collected at other western Atlantic drill sites, we have estimated capacities of about 16 Gt for the shallower (unit 90) and up to 175 Gt for the deeper (unit 120) potential subseafloor sinks.

At present, the only subseafloor geologic storage site for CO_2 is operated by Statoil in the Norwegian North Sea. The sinks identified offshore from the Carolinas are not as well characterized as the North Sea example and would require investigation to determine suitability and to refine capacity estimates. Legal, regulatory, and policy implications of subseafloor geologic storage of CO_2 are unresolved at this time. However, in November 2006, a resolution was adopted by members of the 1996 Protocol of the London Convention to "establish the legality of storing CO_2 in sub-seabed geologic formations." Guidelines for scientific assessment of the potential for subseafloor CO_2 storage will be finalized and presented to the international community soon (IEA, 2006).

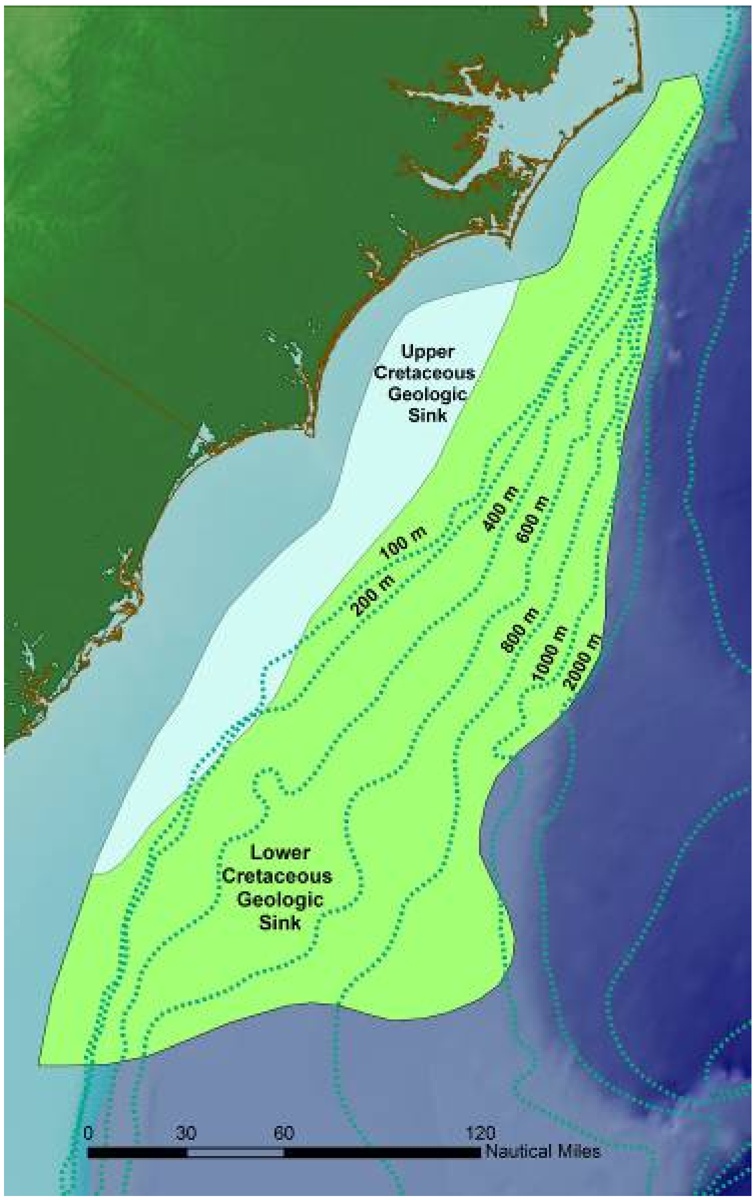


Figure ES-6. Upper and Lower Cretaceous Atlantic subseafloor sinks. (modified from Hutchinson et al., 1996, 1997). Contoured water depth (m) shown in blue dashed lines (irregular contour interval). Depth from sea level to seafloor increases with darker shades of blue.

Because subsurface units underlying much of the Carolinas are unsuitable for long-term storage of CO_2, we looked outside the states for other potential geologic sinks. Two geologic units within the Appalachian Plateau province contain potential CO_2 sinks (1) the Mt. Simon Formation and (2) the Knox Group (fig. ES-3). Data for the Mt. Simon unit in Tennessee are from Advanced Resources International, Inc. (ARI). Depth to base of Mt. Simon ranges from 1,200 to 2,400 m (4000 to 8,000 ft) (fig. ES-7), and thickness throughout is approximately 30 m (~100 ft). Capacity of the Mt. Simon unit is estimated at 2.5 Gt. Additional storage in this unit may extend into adjacent states, but this possibility has not yet been assessed.

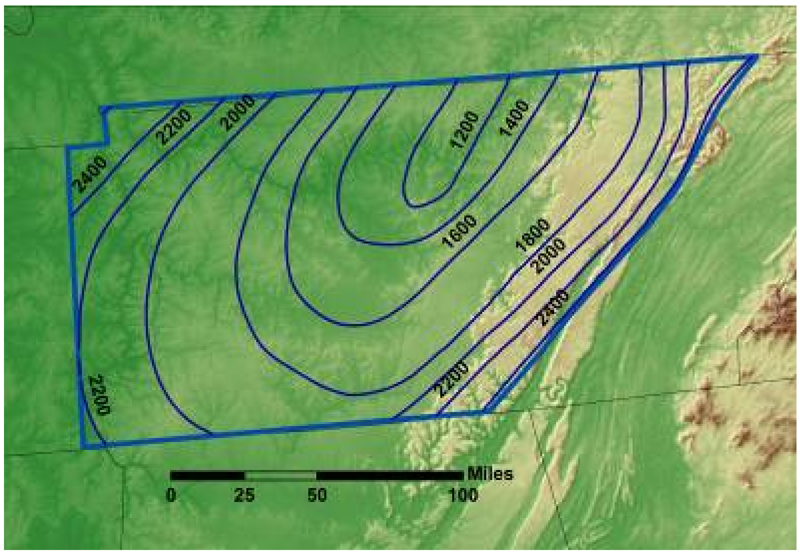


Figure ES-7. Base of Mt. Simon Formation in meters. Modified from ARI data on the Mt. Simon Formation (Maria Fonkin, pers. comm., 2005).

Hydrocarbons (primarily gas) have been produced from Knox Group rocks since the early 1960's, and the potential for future natural gas production from the Knox Group is great within eastern Kentucky and West Virginia (Baranoski et al., 1996). The Knox Group also has great potential for storage of greenhouse gasses. Depth below ground to the top of the Knox Group sink ranges from 800 m (2,600 ft) in eastern Kentucky to 2,600 m (8,500 ft) in southern West Virginia (fig. ES-8a). Thickness of strata in the Knox Group in this area ranges from 500 to 1,200 m (1,650 to 3,950 ft) (fig. ES-8b). Capacity of the Knox Group is estimated at about 30 Gt.

The Upper Cretaceous Tuscaloosa Formation in southwestern Alabama and the Florida panhandle is another out-of-state, potential CO_2 sink (fig. ES-3). Primary sources of information on the geometry, composition, and thickness of the Lower Tuscaloosa strata are geophysical logs of wells drilled for (1) oil and gas exploration and production, (2) disposal of co-produced saline water, and (3) industrial waste disposal. Depth to the top of the Tuscaloosa sink ranges from about 1 to 3 km (0.6 to 2 mi); thickness ranges from 20 to 60 m (70 to 200 ft) (Miller, 1979, 1990; Mancini et al., 1987; Renkin et al., 1989), and unpublished information was provided by the Florida Geological Survey (pers. comm., 2006). A capacity of 9.8 Gt is estimated for this area. Additional assessment of the Tuscaloosa in Mississippi is now under way as part of SECARB studies.

(a) (b)

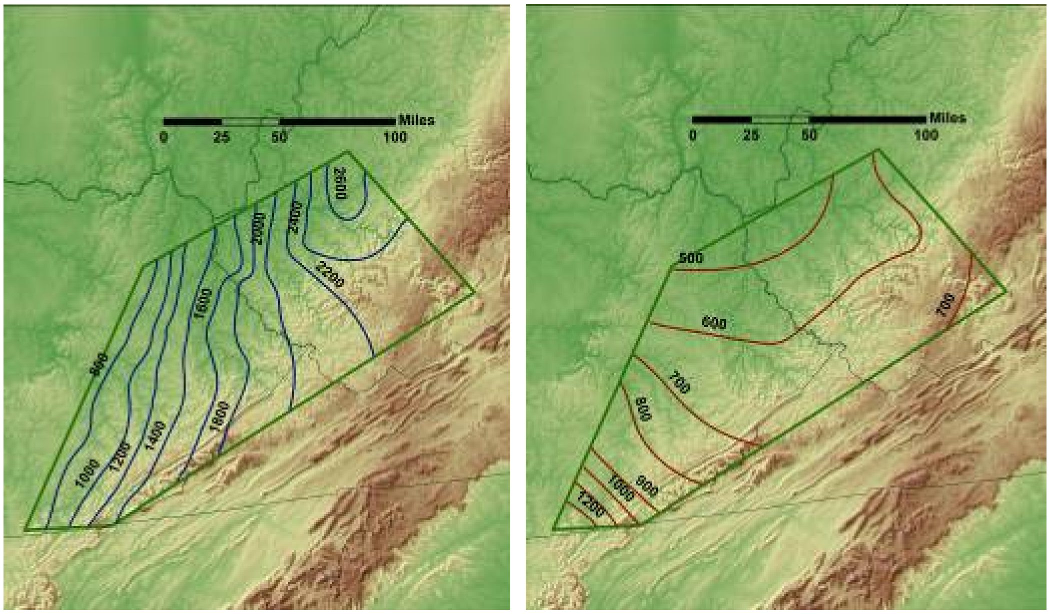


Figure ES-8. Potential Knox Group geologic sink; (a) structure contour on top of Knox (m) and (b) thickness of Knox (m). From Baranoski et al. (1996); Shumaker (1996). Elevation of land surface increases from green to yellow to brown.

The Upper Cretaceous Tuscaloosa Formation in southwestern Alabama and the Florida panhandle is another out-of-state, potential CO_2 sink (fig. ES-3). Primary sources of information on the geometry, composition, and thickness of the Lower Tuscaloosa strata are geophysical logs of wells drilled for (1) oil and gas exploration and production, (2) disposal of co-produced saline water, and (3) industrial waste disposal. Depth to the top of the Tuscaloosa sink ranges from about 1 to 3 km (0.6 to 2 mi); thickness ranges from 20 to 60 m (70 to 200 ft) (Miller, 1979, 1990; Mancini et al., 1987; Renkin et al., 1989), and unpublished information was provided by the Florida Geological Survey (pers. comm., 2006). A capacity of 9.8 Gt is estimated for this area. Additional assessment of the Tuscaloosa in Mississippi is now under way as part of SECARB studies.

Source-Sink Matching Constraints

Part of the source-sink matching process requires estimates of the cost of CO_2 transport to a specific potential geologic sink. For purposes of this discussion, we focused on the potential for transportation by pipeline. Estimates of pipeline costs for this study were conducted by the MIT Laboratory for Energy and the Environment in late 2006. Pipeline cost estimates (in 2006 dollar equivalents for materials) include pipeline construction, right-of-way acquisition, and operation. Cost estimates for CO_2 pipeline construction are based on cost data for natural gas pipelines. This may have resulted in an underestimate of costs to build CO_2 pipelines because of the greater CO_2 wall thickness required to contain supercritical (high pressure and temperature) CO_2. Neither the cost of capture/separation at the plant nor the cost of compression and injection at the CO_2 storage site are included. These elements are beyond the scope of this assessment, which is to match sources with sinks and provide a relative index of cost escalation as the distance between sources and sinks increases.

After identifying CO_2 sources in the Carolinas and using the potential geologic sinks identified by the Bureau of Economic Geology (BEG), MIT workers evaluated source-sink matching over an assumed 25-yr project lifetime. They used a Geographic Information System (GIS) method of matching sources and sinks that considers optimal pipeline route selection and capacity constraints of individual sinks. Because pipeline construction costs vary considerably according to local terrain, number of crossings (waterway, railway, highway), and the traversing of populated places, wetlands, and national or state parks, the group constructed a digital terrain map that allows ranking of these factors.

MIT generated pipeline-transport algorithms using the Carnegie Mellon University (CMU) correlation (McCoy, 2006). Because the MIT source sink matching program develops a minimum cost curve, it favors sinks that are closer to potential sources and automatically excludes more distant sinks. In order to obtain pipeline estimates for all potential sinks presented in this study, MIT used a multiple scenario approach that alternatively excluded nearby sinks so as to force utilization of more distant sinks. Following are constraints for the five possible scenarios:

- Scenario 1 includes all potential sinks,
- Scenario 2 considers all sinks except the Hatteras area,
- Scenario 3 considers all sinks except the Hatteras area and subseafloor Unit 90 (Upper Cretaceous) in order to force pipeline estimates for subseafloor Unit 120 (Lower Cretaceous),
- Scenario 4 excludes the Hatteras area, subseafloor Unit 90 (Upper Cretaceous), and SGB to force pipeline estimates for Mt. Simon sink,
- Scenario 5 excludes the Hatteras area, subseafloor Unit 90 (Upper Cretaceous), SGB, and Mt. Simon to force pipeline estimates for Tuscaloosa sink in Alabama/Florida.

Summaries of estimated costs (in 2006 dollar equivalents for materials) for pipelines between selected sources and potential target sinks are presented for each of the five scenarios (table ES-1). Total power output of the plants served ranges from 25.8 gigawatts (GW) for Scenario 1 to 24.5 GW for Scenario 5. Total pipeline construction costs range from \$3.8 billion for Scenario 1 to \$4.3 billion for Scenario 5. Average transportation costs vary from \$3.56 to \$4.21 per metric ton of CO_2.

Costs for Scenario 1 are lowest because only those potential sinks closest to the Carolinas power plants—Hatteras, Knox, Unit 90, and SGB—are utilized (table ES-1, fig. ES-3). The purpose of running MIT's GIS algorithms using scenarios 3, 4, and 5 was to obtain estimated costs for utilizing the more distant potential sinks—subseafloor unit 120, Mt. Simon, and Tuscaloosa—for geologic storage of CO_2.

Table ES-1. Estimated cost summary (in 2006 dollar equivalents for materials) for five sink scenarios (for power plants with transportation cost <10$/t CO_2).

SINK OPTIONS	TOTAL CONSTRUCTION COST (BILLION $)	TOTAL CO_2 STORED IN 25 YEARS (GT[1])	TOTAL DESIGN CAPACITY (GW)	AVERAGE COST ($/TON CO_2)	AVERAGE DISTANCE[2] (km)	TARGET SINKS
Scenario 1	3.8	4.2	25.8	3.56	299	Hatteras, Knox, Unit 90, SGB
Scenario 2	3.8	4.1	25.3	3.63	322	Knox, Unit 90, SGB
Scenario 3	4.0	4.1	24.8	3.84	344	Knox, Unit 120, SGB
Scenario 4	4.2	4.0	24.5	4.17	370	Knox, Mt. Simon, Unit 120
Scenario 5	4.3	4.0	24.5	4.21	373	Knox, Unit 120, Tuscaloosa

[1]Gt = 1 billion metric tons
[2]Flow-rate-weighted-average pipeline distance

Discussion

Most of the power plants in the Carolinas are underlain by geologic units that are not suitable for long-term storage of large volumes of CO_2. The Blue Ridge and Piedmont physiographic provinces of the Appalachian Mountains in western portions of the Carolinas are underlain by crystalline rocks that lack sufficient overlying seals to (1) trap CO_2 in the subsurface or (2) keep it from interacting with fresh groundwater. Sediments of the Atlantic Coastal Plain are not thick enough to host CO_2 sinks and contain deep freshwater aquifers. An exception within the Carolinas is an isolated sedimentary basin encompassing the southernmost part of South Carolina that lies within the South Georgia Basin.

Subsurface storage of CO_2 generated in the Carolinas will probably require construction of pipelines to geologic sinks located some distance away from the power plants. The most likely potential geologic sinks for CO_2 generated in the Carolinas are located in (1) the South Georgia Basin (southernmost South Carolina, eastern Georgia, and extending offshore 50 to 75 mi (80 to 120 km), (2) the offshore in strata approximately 0.6 to 1.9 mi (~1 to 3 km) below the Atlantic seafloor, and (3) the Knox Formation in eastern Kentucky and southwestern West Virginia. The CO_2 storage potential for the offshore Atlantic margin is unexplored, but preliminary considerations suggest that CO_2 sequestration options are significant along the entire eastern seaboard. Given the limited sink availability in onshore locations of the eastern U.S., and the potentially promising offshore locations, subseafloor injection warrants further evaluation.

Estimates of storage capacity of the potential geologic units are summarized in table ES-2. These estimates are based on limited and generalized data sets, which are primarily from published literature. More accurate estimates of capacity for geologic sinks will require site-specific, detailed geologic investigations. In addition, assessment of the potential geologic sinks is based solely on geologic suitability. Environmental, economic, and socio-political issues will need to be considered before determining which geologic sinks are most suitable for CO_2 storage.

Table ES-2. MIT estimates of CO_2 storage capacity.

POTENTIAL SINK	CAPACITY ESTIMATES[1] (Gt)
SGB Triassic units Atkinson-Tuscaloosa Cape Fear	~15
Offshore Sinks Unit 120 Unit 90	 ~178[2] ~16[2]
Hatteras Area	n.a.[3]
Mt. Simon	~3
Knox	~32
Tuscaloosa	~10

Notes:

1. CO_2 storage efficiency estimated as 2 percent and all the aquifers are assumed closed.
2. CO_2 density in the offshore sites assumed to be 700 kg/m^3.
3. Detailed data are not available.

Costs associated with CCS can be separated into two categories—(1) those associated with CO_2 capture and separation and (2) those associated with transportation and storage. Deutch et al. (2007) estimated that the cost of CO_2 capture and pressurization will greatly exceed the cost of CO_2 transportation and storage. The cost estimates presented in this summary report represent possible scenarios for pipeline transport of CO_2 from power plants in the Carolinas to potentially suitable geologic sinks.

Pipeline construction costs are the primary cost factor in the various scenarios, and they vary according to type of terrain that must be traversed. CO_2 transport costs are estimated in terms of \$/ton CO_2, which is the total cost divided by the CO_2 flow rate. Hence, transporting CO_2 at a higher flow rate results in lower transportation costs. Average transportation costs estimated by MIT for the five different scenarios vary from \$3.56 to \$4.21 per metric ton of CO_2 in 2006 equivalent dollars. These costs might be low because (1) MIT based pipeline construction costs on those required to build natural gas pipelines; CO_2 pipelines might be more expensive because of the greater wall thickness needed to contain supercritical (high temperature and high pressure) CO_2, (2) fluctuations in the price of steel, (3) uncertainty in the cost escalation factor for building offshore pipelines.

Introduction

Options for reduction of atmospheric emissions of greenhouse gases (GHG) are currently under consideration by both government (Federal and State) and industry, and interest will continue to expand (e.g., Herzog, 2001; DOE, 2005; Hoffman, 2006). Carbon dioxide (CO_2) occurs naturally in the atmosphere, but over the past few centuries concentrations have increased as a result of emissions from anthropogenic sources. At this time CO_2 emissions are not regulated in the U.S.; however, discussions on reducing the intensity of GHG emissions are under way. Technologies to separate, capture, and concentrate CO_2 from industrial emissions are under development but are not yet ready for commercial use.

Geologic storage is a process whereby concentrated CO_2, captured from industrial sources, will be injected into suitable subsurface strata or geologic "sinks" and stored for significant periods of time (thousands of years) through physical or chemical trapping (Bachu et al., 1994). The combination of carbon capture and storage is known by the acronym CCS. According to a recently released report by researchers at Massachusetts Institute of Technology (MIT) (Deutch et al., 2007), "CCS is the critically enabling technology to help reduce CO_2 emissions significantly while also allowing coal to meet the world's pressing energy needs."

Results presented here update and supersede previous CO_2 source-sink matching analyses (Hovorka et al., 2000) used in Phase I of the Southeast Regional Carbon Sequestration Partnership (SECARB), which was funded by the Department of Energy (DOE) through the Southern States Energy Board (SSEB). Funding for this study has been provided by Carolinas power companies Duke Energy, Progress Energy, Santee Cooper Power, and South Carolina Electric and Gas, in cooperation with the Electric Power Research Institute (EPRI) and SSEB.

The focus of this study is to identify geologic units containing deep saline reservoirs (brine-filled formations), or geologic sinks that might be suitable for effective, large-volume geologic storage of CO_2 generated in North and South Carolina. An additional objective is to provide information in a format that can be used to guide policy makers and educate the public about geologic storage options for North and South Carolina.

CO_2 Storage Requirements

Deep saline reservoirs are one type of geologic sink. These require (1) continuity and integrity of an overlying seal; (2) depth sufficient to maintain CO_2 at high density (which corresponds to depths greater than 800 m (>2,400 ft) below the surface); (3) depth below underground sources of drinking water (USDW), where total dissolved solids exceed 10,000 parts per million (ppm); and (4) storage capacity sufficient to prevent displacement of saline water into overlying freshwater-bearing units. Accurate prediction of the storage properties of geologic units will permit semiquantitative analysis of CO_2 capacity and will allow site-specific assessment to proceed more readily.

Buoyancy-driven flow in the absence of immobilization of CO_2 from dissolution into brine or trapping as a result of mineral-fluid interactions makes integrity of seal rocks a critical issue (e.g., Hovorka et al., 2004). The critical point of CO_2 is at a temperature of 31°C (87.9 °F) and pressure of 73.8 bars (1070.7 psi). Above this temperature and pressure, CO_2 is not liquid or gas but exists in supercritical phase, which has properties of both liquid and gas (Jarrell et al., 2002). Supercritical CO_2 will partially dissolve into brine held in pore spaces of a deep saline reservoir. The remaining CO_2 will form a free (immiscible) supercritical phase that will displace brine (Doughty and Pruess, 2003). Temperature and pressure sufficient for keeping CO_2 in supercritical phase generally corresponds to depths greater than 800 m (2,400 ft) below the land surface.

Monitoring for CO_2 leakage into groundwater is an essential part of the overall strategy for assessing suitability of geologic sinks (Doughty et al., 2004; Nance and others, 2005; Hovorka, 2006; Hovorka and others, 2006). CO_2 could migrate into groundwater through improperly plugged boreholes, through faults or joints that penetrate seals and intermediate strata, and by flow through the seals and intermediate strata where cross-formational permeable pathways are encountered by CO_2 injectate plumes.

In 1974 the Safe Drinking Water Act was passed in the U.S. Congress (U.S. House of Representatives, 1974) and is enforced by the Environmental Protection Agency (EPA). In this Act, USDWs are defined as water-bearing units with less than 10,000 ppm or milligrams per liter (mg/L) total dissolved solids (TDS). Water-bearing units with less than 10,000 ppm TDS cannot be used to store injected wastes. CO_2 is not a waste according to the Safe Drinking Water Act, but it is prudent to utilize reservoirs for storage of it in geologic sinks that are deeper than the deepest USDW in any given area.

Procedures for estimating volume of CO_2 that can be injected into a particular saline reservoir (known as capacity of the reservoir) are still being debated among U.S. and international researchers engaged in CO_2 storage issues. In subsequent sections we provide details of data used as input to capacity estimates for each potential geologic sink identified during this study.

Part of the assessment of a potential geologic sink is estimation of CO_2 capacity and the cost of pipeline transport to a specific site. Estimates of pipeline costs (cost of pipeline construction, right-of-way acquisition, and operation—but not CO_2 injection) and potential storage capacity of geologic sinks were conducted in 2006 at Massachusetts Institute of Technology (MIT) Laboratory for Energy and the Environment by Howard Herzog and his research team in late 2006. The pipeline cost estimates (in 2006 dollar equivalents for materials) include neither the cost of capture/separation at the plant nor cost of compression or injection at the CO_2 storage site, which are beyond the scope of this assessment.

In recent work to evaluate costs of CCS, MIT researchers (Deutch et al., 2007) estimated that the cost of CO_2 capture and pressurization will greatly exceed the cost of CO_2 transportation and storage. Herzog's MIT group has developed a Carbon Management Geographic Information System (GIS) tool that utilizes ArcGIS© (software developed by Environmental Systems Research Institute). We converted data needed to estimate reservoir capacity into GIS format and provided it to the MIT group. This simplified data management, analysis, and presentation of information. For example, many of the figures in this report were generated in ArcGIS©.

Geologic Framework and Storage Constraints

In western portions of North Carolina and South Carolina, highly fractured, crystalline and metamorphic rocks of the Blue Ridge and Piedmont physiographic provinces of the Appalachian Mountains are present at the surface. Fractured crystalline rocks can serve as limited-capacity fluid reservoirs, but in this area the rocks are unsuitable for CO_2 storage owing to absence of overlying sedimentary seals that would prevent escape of injected gas to the atmosphere. In the eastern portions of North and South Carolina, sedimentary rocks of the Coastal Plain physiographic province are underlain by Piedmont-like fractured crystalline rocks. However, sediment thicknesses over much of the Coastal Plain are insufficient to allow emplacement of CO_2 at adequate pressure, or at depths far enough below freshwater resources to provide good environments for geologic sequestration. Consequently, there are few options for geologic storage of CO_2 within the Carolinas (fig. 1).

This report begins with a brief discussion of the geologic history of the southeastern U.S. because that history is fundamental to understanding the suitability of different areas to CO_2 storage. This discussion is followed by description of areas that are unsuitable or that have low potential for geologic storage. Further on we present data acquired *to date* for assessment of sinks identified for potential geologic storage of CO_2 generated in the Carolinas. The sinks are primarily located outside of the Carolinas underlying adjoining states to the northwest and southwest, and below the Atlantic seafloor offshore from the Carolinas and Georgia (fig. 1). Initial estimates of sink capacities and costs to build pipelines from power plants in North and South Carolina to the potential geologic sinks have been completed by MIT and are summarized the end of this report.

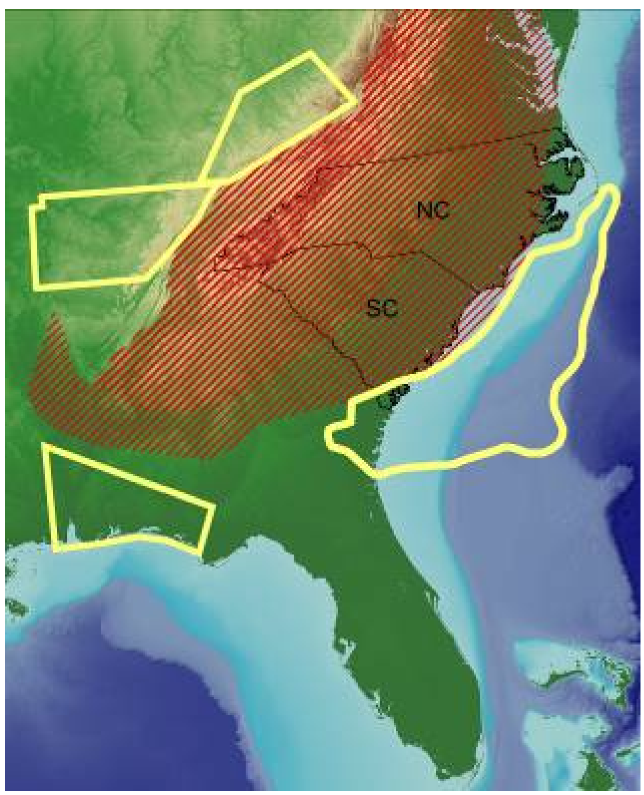


Figure 1. Location of areas considered for potential geologic storage of CO_2 generated in North and South Carolina outlined in yellow. Areas unsuitable for geologic storage of CO_2 (red stippled pattern).

All data used to evaluate the suitability of the potential geologic sinks are from preexisting geologic studies, the majority are from published literature. During this reconnaissance level study we have gathered information sufficient to identify geologic sinks that warrant further detailed assessment. Target sinks reported here should be viewed as candidate sites that passed an initial screening process and not final recommendations for geologic storage of CO_2. This initial assessment of geologic sinks with potential for long-term storage of CO_2 is unencumbered: it is based solely on the suitability of subsurface units to store CO_2; it does not take into account environmental, economic, or socio/political issues that would need to be balanced with geologic suitability.

Geologic History of the Southeastern United States

Properties that control the suitability of geologic units for storage of CO_2 in the southeastern U.S. are directly related to geologic history of the southeastern edge of the North American continent. The Atlantic Ocean has opened and closed repeatedly over geologic periods of time as a result of continental drift and seafloor spreading. Tectonism, or mountain building, which is often a result of continental collision and rifting (tearing apart), has occurred in the Appalachian Basin along the Atlantic margin of North America twice since early Paleozoic time, around 500 to 600 million years ago (ca. 500–600 Ma) (Wilson, 1966). The present-day Appalachian Mountains were formed during most recent continental collision in late Paleozoic time (ca. 250–300 Ma), resulting in formation of the supercontinent Pangaea. Fragmentation of Pangaea, with accompanied seafloor spreading and opening of the present-day Atlantic Ocean, began in late Paleozoic to early Mesozoic (ca. 200 Ma) time (King, 1959; Wilson, 1966; Milici, 1996; Shumaker, 1996). Figure 2 shows relative positions of the North American and African continents after breakup of Pangaea.

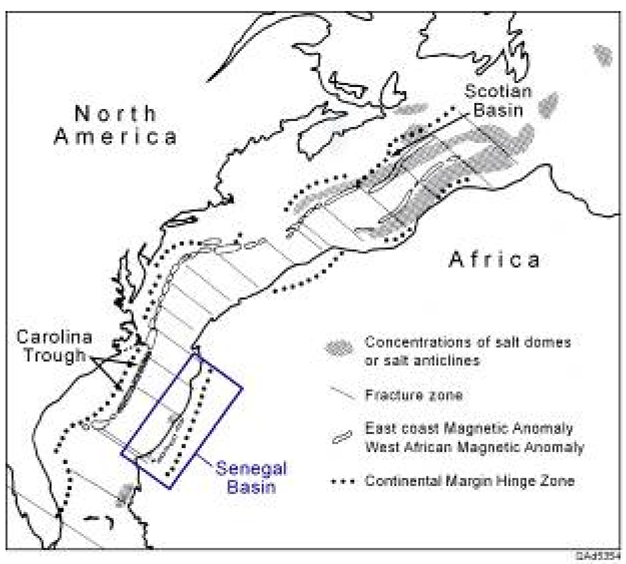


Figure 2. Relative positions of North American and African continents in Middle Jurassic time (~175 Ma), after initial opening of the present-day Atlantic Ocean. Modified from Hutchinson et al. (1982).

The present-day Appalachian Mountains extend from Newfoundland to Alabama roughly parallel to the U.S. Atlantic coast. Except for the portion in Newfoundland, the mountains are divided into three sections—northern, central, and southern. Only the southern Appalachians, which extend from Roanoke, Virginia, southwestward into Alabama, are pertinent to CO_2 source-sink studies in the southeastern U.S. The Southern Appalachian Mountains are subdivided longitudinally from northwest to southeast, into the Appalachian Plateau, the Appalachian Valley and Ridge, the Blue Ridge, and Piedmont provinces (fig. 3). A schematic diagram showing the subsurface relationship of rocks in the Southern Appalachian Mountains in cross section is depicted in figure 4.

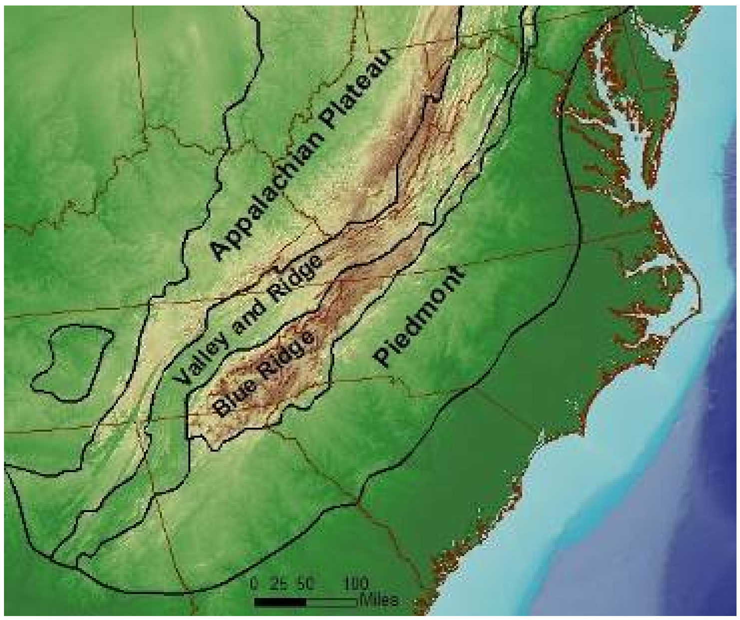


Figure 3. Physiographic provinces of present-day Appalachian Mountains. Physiographic provinces of Appalachian Mountains modified from Fenneman and Johnson (1946); digital elevation models from NOAA (2006) (land) and Scripps (2006) (ocean floor). Elevation of land surface increases from green to yellow to brown.

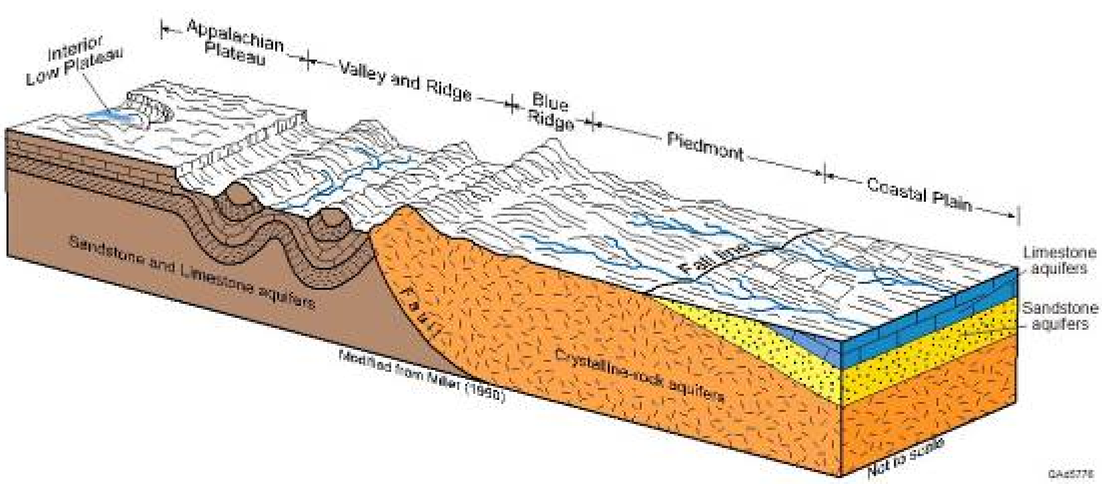


Figure 4. Schematic cross section from NW Alabama to south Georgia Coastal Plain.

The two potential sinks west of the Carolinas (fig. 1) lie within nearly flat-lying sediments of the Appalachian Plateau that were only mildly deformed during regional tectonicm. Coastal Plain deposits, which are seaward of the Appalachian Mountains (eastward from the Carolinas and in southern portions of Georgia and Alabama) are composed of detritus eroded from the Appalachian Mountains. All the other potential sinks introduced in this document lie within the seaward dipping sediments of the Coastal Plain.

Crystalline rocks of the Piedmont region are younger than those of the Blue Ridge and represent metasedimentary and granitic to ultramafic plutonic (intrusive igneous) rocks that were pasted to the eastern edge of the North American continent in middle to late Paleozoic (ca. 400 Ma) time during closing of the proto-Atlantic Ocean (King, 1959; Milici, 1996). These regions are composed of highly deformed rocks that are not suitable for subsurface storage of CO_2.

Rift basins provide a record of the earliest stages of continental breakup. A belt of rift basins parallels the Atlantic coast of North America from Nova Scotia to southern South Carolina, where it curves westward through southern Georgia, Alabama, and Mississippi. The basins were formed by tensional forces associated with breakup of the supercontinent Pangea beginning in late Paleozoic time (ca. 250–300 Ma) (Klitgord et al., 1988; Ziegler, 1988) (fig. 5). All of the basins are floored by Piedmont crystalline basement rocks and filled with Triassic to Jurassic-age (ca. 150–250 Ma) clastic (sand, silt, and clay) sedimentary rocks.

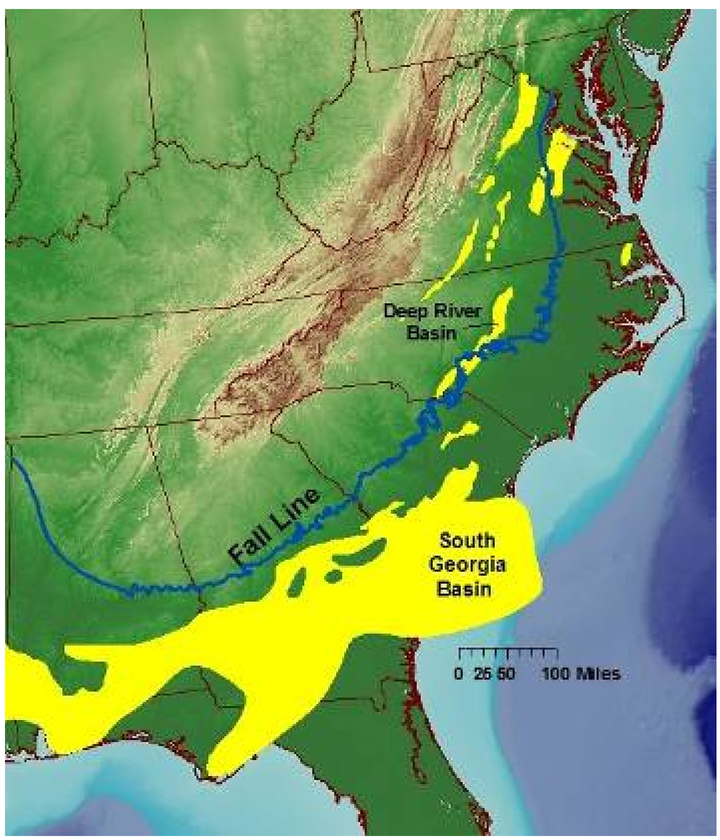


Figure 5. Mesozoic basins of the southeastern U.S. (yellow). Modified from Klitgord and Behrendt (1979); Olsen et al. (1991); Hutchinson et al. (1997). Fall line marked in blue.

The Fall Line is a boundary corresponding with the landward extent of Atlantic coastal plain sediments; this name arose from the abundant water falls or rapids that form along rivers as they cross from resistant Piedmont crystalline rocks to softer sedimentary rocks of the coastal plain. Triassic-age rocks in rift basins west of the Fall Line crop out at the surface and are often deformed and slightly metamorphosed. The rocks within the exposed rift basins are not suitable for subsurface storage of CO_2. Triassic rift basins seaward of the Fall Line are buried by varying thicknesses of coastal plain sediments (Klitgord and Behrendt, 1979; Olsen et al., 1991).

The South Georgia Basin is a northeast-southwest trending buried Triassic rift basin hypothesized to represent the pre-Appalachian Mountain continental margin of North America. It reportedly received 5-6 km thickness of sediments eroded from the Appalachian Mountains (Nelson et al., 1985). Present day Florida southeast of this basin, called Suwannee terrane, is thought to be a fragment of continental crust originally attached to Gondwanaland (ancestral African and South American continents). The Suwannee terrane (also known as a microcontinent) merged with ancestral North America during closing of the proto-Atlantic Ocean (earlier phases of Appalachian tectonism) in Permian time (ca. 260 Ma) (Horton et al., 1989; King, 1959; McBride et al., 1989; Nelson et al., 1985; Thomas, 2006).

A thick wedge-shaped accumulation of terrigineous material eroded from the Appalachian Mountains filled the South Georgia Basin rift. The sediments thicken southeastward from the Fall Line in central South Carolina and Georgia toward the southeast (Barker and Pernik, 1994). These strata become more carbonate-rich and thicken from north to south along the coast, reaching maximum thicknesses of 1400 m or more in the axis of the South Georgia Basin (Brown et al., 1979; Gohn et al., 1980). This thick sequence of strata hosts three vertically stacked geologic sinks. South of the embayment, stratigraphically equivalent units are dominantly carbonates of the Florida platform (Gohn et al., 1980).

Areas Unsuitable for Geologic Storage

Vast areas of the Appalachian Mountains in southeastern U.S. are either unsuitable or have low potential for geologic storage of CO_2. Rocks in the Valley and Ridge are less favorable for geologic storage because they are extensively folded and faulted. Nor are the fractured crystalline rocks of the Blue Ridge and Piedmont provinces (Rogers, 1949; Shumaker, 1996) suitable for CO_2 storage. Much of the Atlantic Coastal Plain is unsuitable for storage of CO_2 because sequences of sedimentary rocks are too thin to host CO_2 storage. In addition, groundwater close to the coast retains total dissolved solids (TDS) content as low as 1,300 ppm to depths as great as 200 m (660 ft) near Cape Fear, South Carolina (Kohout et al., 1988), which is well below the EPA cutoff of 10,000 ppm TDS for drinking water.

Valley and Ridge Province

As discussed in Shumaker (1996), the Precambrian-age rocks present at the surface in the Blue Ridge form the basement beneath the Appalachian Plateau and Valley and Ridge provinces. Rocks composing the Valley and Ridge represent a block of Appalachian basin sediments that was thrust westward during the most recent episode of trans-Atlantic continental collision (e.g., Shumaker, 1996). Not only are strata in the

Valley and Ridge province of the Southern Appalachian Mountains folded and faulted, drilling has revealed the presence of complex buried structures that show little surface expression. Less-competent layers of shale, salt, and thinly bedded carbonates, which acted as décollement or detachment zones for large-scale thrust faults, contain soft-sediment deformation features (Rogers, 1949; Spencer, 1972).

Because the Valley and Ridge province contains oil and gas reservoirs (Roen and Walker, 1996), it most likely contains geologic environments that could host CO_2 storage. However, identifying and assessing these local features requires in-depth investigation outside the scope of this regional survey. Targeting geologic sink horizons that have undergone complex structural deformation like observed in the Appalachian Valley and Ridge could require multiple drilling attempts and, hence, become prohibitively expensive (figs. 6 and 7).

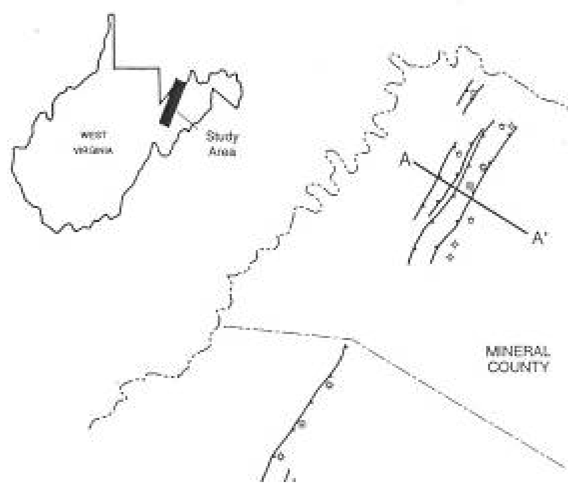


Figure 6. Location of Appalachian Plateau to Valley and Ridge cross section shown in figure 7. Source: Harper and Patchen (1996).

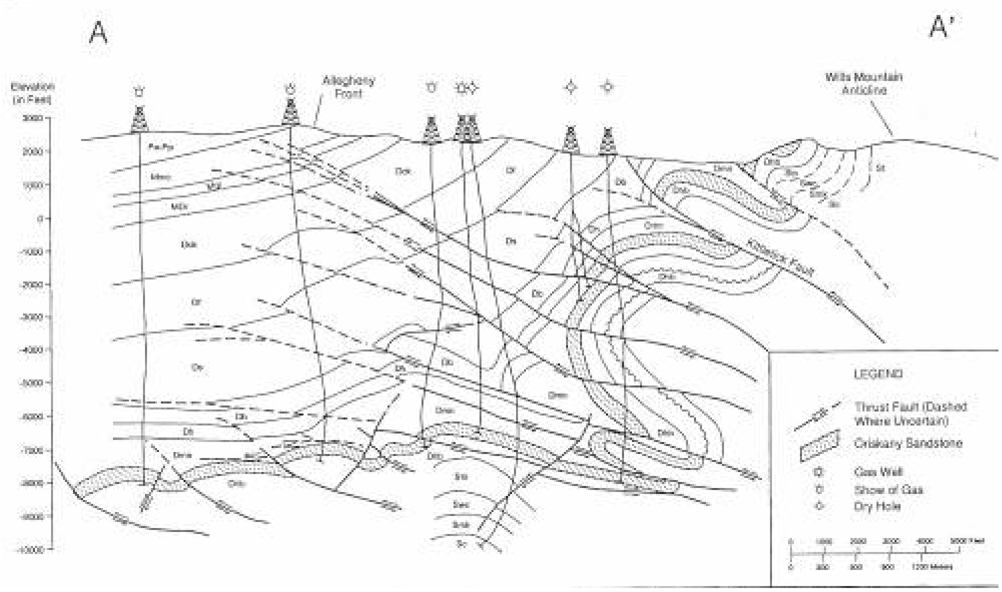


Figure 7. Cross section showing increase in structural complexity going from Appalachian Plateau (A) to Appalachian Valley and Ridge (A′). Source: Harper and Patchen (1996).

Blue Ridge and Piedmont

Fractured and metamorphosed Blue Ridge and Piedmont rocks are exposed at the surface throughout much of North and South Carolina. In late Paleozoic time (ca. 250-300 Ma), Precambrian-age crystalline rocks were thrust westward over younger Paleozoic rocks forming the Blue Ridge Mountains, resulting in brittle deformation (extensive fracturing and faulting). As stated by Spencer (1972), fractures across most of the Blue Ridge province are widely spaced (~1 ft), but near major faults fracturing becomes so intense that in some places individual crystals are shattered.

The capacity of fractured crystalline rocks to store large volumes of CO_2 is limited. Rocks that have undergone multiple episodes of brittle deformation, such as those present in the Blue Ridge and Piedmont provinces, have high permeability, if fracture networks are connected, but low matrix porosity. They therefore have limited potential for CO_2 to be dissolved or stored in pore systems trapped as a residual phase by capillary forces. The distribution of CO_2 injected into these rocks would most likely be difficult to predict and therefore expensive to monitor. Most importantly, there are no overlying sedimentary rocks to provide a seal, so injected CO_2 would not be isolated from the atmosphere. We therefore rule out the extensively fractured crystalline (plutonic and metamorphic rocks of the Blue Ridge and Piedmont physiographic provinces of the Appalachian Mountains—not just in the Carolinas) as attractive candidates for large-volume CO_2 storage.

Coastal Plain

The Fall line, which separates the eastern Piedmont province from the Coastal Plain (blue line in fig. 5), represents the landward extent of sediments deposited on crystalline basement rocks (Horton and Zullo, 1991). These sediments become thicker toward the Atlantic coast but only reach thicknesses greater than the 800 m required to create sufficient pressure for geologic storage of CO_2 in (1) Cape Hatteras area of eastern North Carolina and (2) southernmost South Carolina. Figure 8 shows that portion of the Atlantic coastal plain of the southeastern U.S. where sedimentary cover is too thin to provide CO_2 storage.

Throughout most of the Coastal Plain younger sedimentary rocks host fresh groundwater (e.g., Aucott, 1988). Groundwater close to the coast retains TDS content as low as 1,300 ppm to depths as great as 200 m (660 ft) near Cape Fear, South Carolina (Kohout et al., 1988), which is well below the EPA cutoff of 10,000 ppm TDS for drinking water. Injection of CO_2 into freshwater is generally proscribed because of the potential to damage these resources. Water resources of the Coastal Plain have been moderately characterized, but deep aquifers are poorly known because shallow aquifers generally provide sufficient water. There is very little potential for hydrocarbon production along coastal South Carolina, and because the state currently has laws prohibiting subsurface liquid waste disposal, there has been little subsurface research related to petroleum exploration or subsurface disposal of industrial liquid wastes.

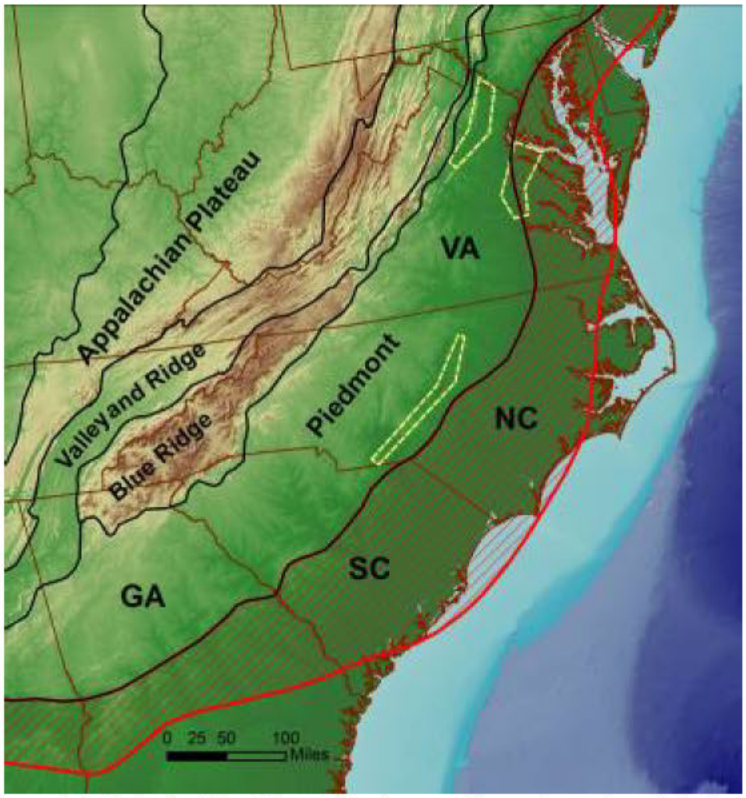


Figure 8. Area of coastal plain (outlined in red) where sediments are too thin for suitable storage of CO_2. Exposed Mesozoic rift basins shown by yellow stippled line.

Exposed Mesozoic Rift Basins

Two major basins in which Mesozoic sediments are present at the surface, the Deep River and the Dan River Basins, lie within North Carolina. The Dan River Basin occurs farther to the west and extends northeastward into Virginia (fig. 8). Surface dimensions of the Dan River basin are ~80 km (~50 mi) long by an average 8 km (5 mi) wide. Thickness of sediments in this basin ranges to as much as 3 km (~1.8 mi); however, they dip steeply (to 65°) to the west and are very brittle (i.e., lots of fractures) (Olsen et al., 1991). This basin is not suitable for storage because many of the fractures extend from deep into the basin to the surface.

Triassic-aged rocks of the Deep River Basin in central North Carolina also occur at the surface. This basin stretches from ~ 25 mi northwest of Raleigh southwestward just across the South Carolina border (fig. 8). The Deep River Basin is divided into three separate subbasins, which are, from northeast to southwest, the Durham, Sanford, and Wadesboro Basins. Approximate dimensions of surface exposure of the three subbasins are: Durham—80 km (50 mi) long × 15 km (9 mi) wide; Sanford—40 km (25 mi) long × 15 km (9 mi) wide; Wadesboro—80 km (50 mi) long × 15 km (9 mi) wide. Approximate depth of the Durham subbasin is 2 km (1.2 mi); both the Sanford and Wadesboro subbasins are thought to be ~3 km (1.8 mi) deep (Olsen et al., 1991). On the basis of detailed review of Deep River Basin studies, we conclude it to be a less favorable location for geologic storage of CO_2. All three subbasins of the Deep River Basin have deep-seated fractures exposed at the surface. In addition, they are characterized by heterogeneous, poorly sorted (lots of clay mixed in with the sand and gravel) sediments that were deposited rapidly (Marine and Simple, 1974). The porosity and permeability of these units are difficult to predict and most likely very low.

A detailed description of the Deep River Basin, provided by Dr. Paul Thayer of the University of North Carolina at Wilmington, is included in Appendix A of this report. Excerpts from Dr. Thayer's report that are directly pertinent to storage of CO_2 in the Deep River basin follow:

> *There are few distinctive beds within the Sanford Formation and no consistently mappable subdivisions (Reinemund, 1955). Fluvial sandstone and mudrock grade into conglomerate toward the Jonesboro fault zone, which forms the southeastern border of the Sanford subbasin. Poorly sorted, matrix-supported conglomerates suggest debris flow deposition, and interbedded clast-supported, imbricated conglomerates indicate braided stream deposition on alluvial fans (Olsen et al., 1991).*
>
> *Two sets of faults have been identified in Deep River basin (Reinemund, 1955). The dominant set strikes northeast-southwest, parallel to the Jonesboro fault zone, and cuts the basin into a series of fault blocks that locally duplicate parts of the basin section. The other set strikes northwest-southeast, nearly perpendicular to the major set, and served as a conduit for many of the diabase dikes. Reinemund (1955) mapped a number of transverse folds in the Sanford subbasin, which are common in Newark Supergroup basins. The axes of the transverse folds trend northwest-southeast in the Sanford subbasin.*
>
> *Sedimentary rocks of the Deep River basin have been intruded and metamorphosed by sheets and dikes of dominantly olivine-normative diabase of probable Jurassic age (Reinemund, 1955; King, 1961, 1971; Burt et al., 1978; Ragland, 1991; Ragland et al., 1968, 1969, 1981, 1983, 1992, 1998). Most dikes trend north and northwest and cut Triassic and pre-Triassic metamorphic rocks. Although overlapped by Cretaceous and younger strata, the dikes have been traced beneath Coastal Plain cover using aeromagnetic data (USGS, 1976a, 1976b; Daniels et al., 1983; Bond and Phillips, 1988).*

As with portions of the Valley and Ridge province, exposed rift basins—all along the east coast—might be considered for storage on a site-specific, case-by-case basis. However, for the purpose of this study, we are not considering them as large-volume, potential CO_2 storage targets.

Potential Geologic Sinks

Sinks with potential for long-term storage of CO_2 generated in the Carolinas are all deep saline reservoirs within host geologic strata. All sinks presented here have been chosen through study of existing and, in most cases, published data. Additional field-data collection and verification will be required to test the suitability of specific injection sites and refine the generalized capacity estimates presented in subsequent questions.

Potential geologic sinks for subsurface storage of CO_2 generated in the Carolinas are located in (1) central Tennessee—Mt. Simon Formation, (2) eastern Kentucky and southern West Virginia—Knox Group, (3) eastern North Carolina—subsurface strata west of Cape Hatteras, (4) southern South Carolina and Georgia coasts—Triassic- and Upper Cretaceous-age units in the South Georgia Basin, (5) Florida panhandle and southwestern Alabama—Upper Cretaceous Tuscaloosa Formation, and (6) Atlantic subseafloor strata offshore from Cape Hatteras, North Carolina, south to Brunswick, Georgia—Lower Cretaceous unit 120 and Upper Cretaceous unit 90 (fig. 9).

Three of the sinks were previously identified. The Mt. Simon Formation sink was described by workers at Advance Resources International (ARI 2005, digital communication). The Knox Dolomite was assessed during SECARB phase I (Hovorka et al., 2005 unpublished report to SSEB). The Tuscaloosa Formation in Alabama was assessed by Hovorka et al. (2000). Here we have converted data covering portions of the Mt. Simon and Knox areas, which are within reasonable distances from the Carolinas, into GIS format. We have also identified an additional area of the Tuscaloosa Formation in Florida and merged it with previous Alabama Tuscaloosa data.

Suitability criteria for geologic storage in deep saline reservoirs include (1) continuity and integrity of an overlying seal; (2) depth sufficient to maintain CO_2 at high density (which corresponds to depths greater than 800 m (>2,400 ft) below the surface); (3) depth below underground sources of drinking water (USDW), where total dissolved solids exceed 10,000 parts per million (ppm); and (4) storage capacity sufficient to prevent displacement of saline water into overlying freshwater-bearing units. In subsequent sections we provide details of data used to estimate capacity for each potential geologic sink.

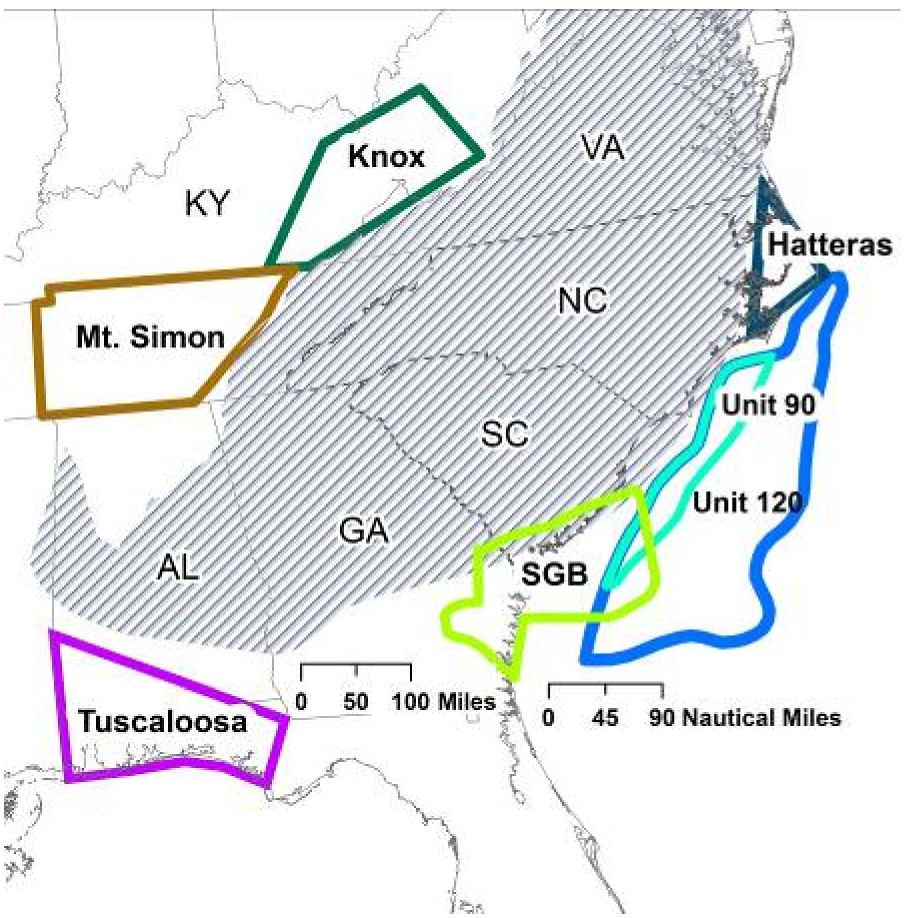


Figure 9. Location of areas considered for potential geologic storage of CO_2 generated in North and South Carolina. SGB = Cretaceous-age units in the South Georgia Basin.

Sinks Closer to the Carolinas

Potential sinks relatively near the Carolinas are located west of Cape Hatteras, NC, in the South Georgia Basin, and offshore below the Atlantic seafloor. Sites farther from the Carolinas are those located in Florida-Alabama, Tennessee, and Kentucky-West Virginia (fig. 9).

Of the three sinks located closest to the Carolinas, we have most extensively evaluated the South Georgia Basin (SGB) and offshore below the Atlantic seafloor. SGB and the area west of Cape Hatteras, NC (Hatteras area), contain thicker accumulations of sedimentary rocks than that found elsewhere along the Carolina Coastal Plain.

<u>Hatteras Area, North Carolina</u>

Sediments west of Cape Hatteras attain a thickness of 2.7 km (1.7 mi) (figures 9 and 10), which is sufficient to contain potential CO_2 sinks. However, literature review to obtain hydraulic properties and other data needed to estimate capacity of specific stratigraphic units was not performed for this study. Developed land use patterns in this ecologically sensitive area negate realistic expectations for obtaining pipeline and drilling permits.

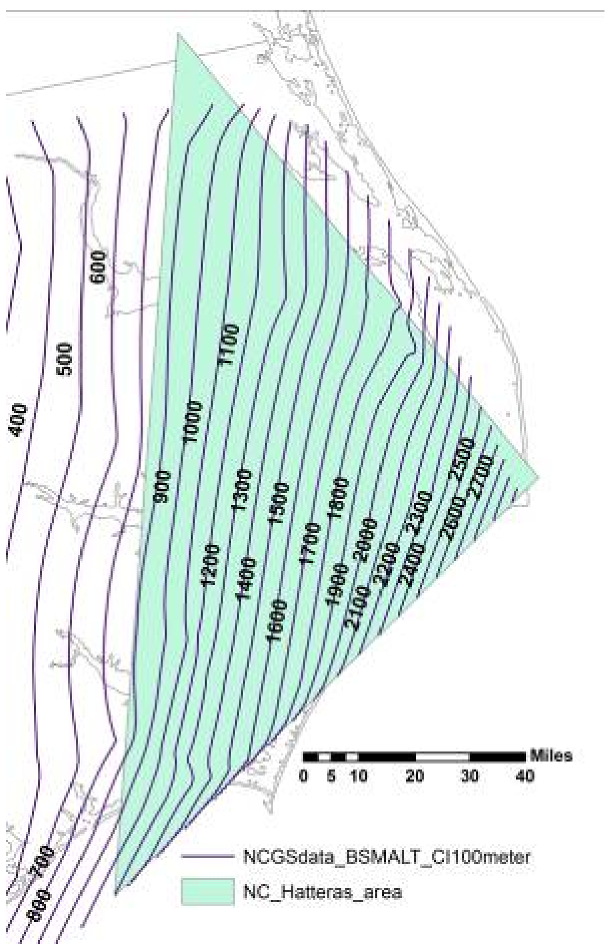


Figure 10. Depth (m) to crystalline basement rocks in the Hatteras area. Contours generated from NCGS well data provided by Dr. Paul Thayer.

<u>South Georgia Basin Sinks</u>

The South Georgia Basin (fig. 9) is the east end of a series of structural basins spanning from Alabama across south-central Georgia, southern South Carolina, and eastward onto the Atlantic continental shelf (fig. 5). The entire series of basins are buried beneath coastal-plain sediments.

Through previous work associated with SECARB, and current work, we have identified three potential sinks in the South Georgia Basin: (1) Late Cretaceous-age Cape Fear Formation (from previous SECARB work), (2) Late Cretaceous-age Tuscaloosa/Atkinson units in Georgia, and (3) multiple intervals in Triassic-age units that extend offshore from South Carolina and Georgia (fig. 11). These sinks partly overlap in map view but span different depth horizons between 800 and 1,300 m (2,600 and 4,300 ft). The outline of SGB in fig. 9 depicts the composite area of these three sinks projected up to land surface.

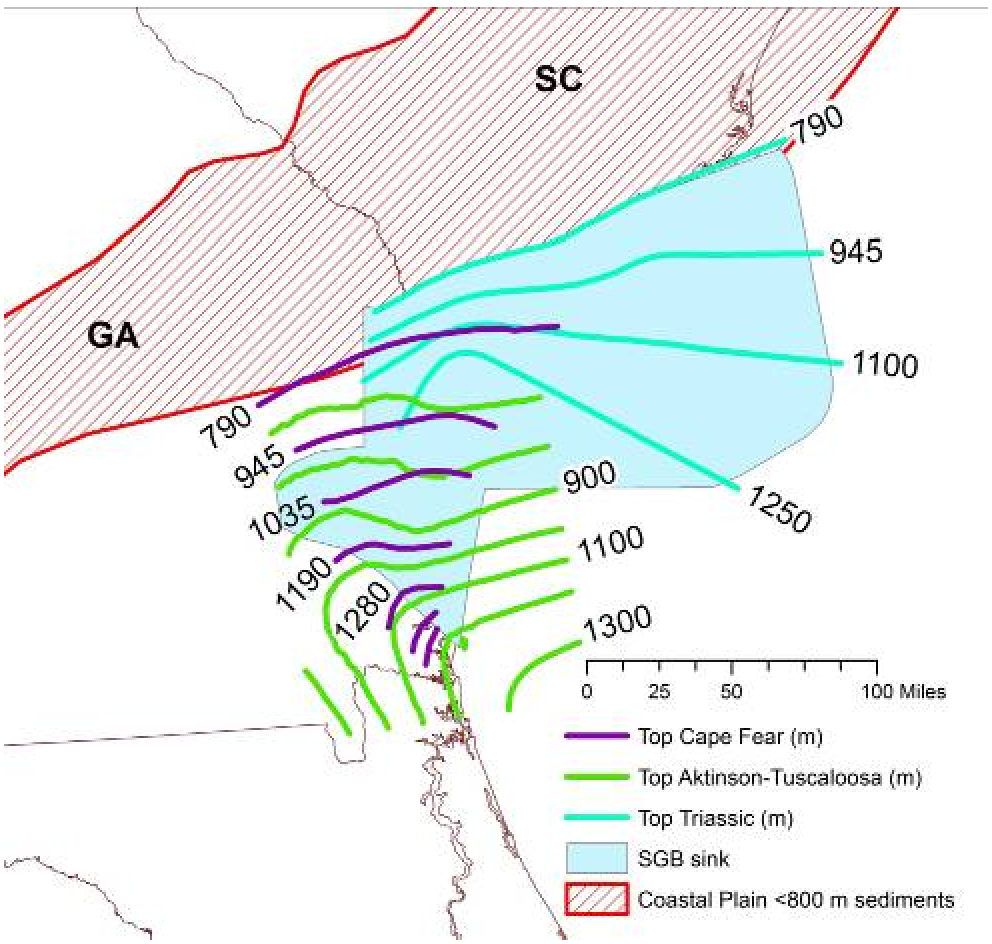


Figure 11. South Georgia Basin Sinks.

Dr. Tom Temples of the University of South Carolina at Columbia provided data interpretations and potential sink intervals for the Triassic units (figures 11 and 12). Much of the interpretation is based on a well log from the Lightsey well drilled by an oil company near Jedberg, South Carolina. BEG converted the data into GIS format and extended contours to the published extents of the SGB. Figure 12a shows top depths of

800 to 1,200 m below the surface and a thickness of 80 to 110 m (fig. 12b) for the Triassic sink intervals. We scaled thickness contours to approximate only those intervals of the Triassic section identified by Dr. Temples as good host strata (table 1).

(a) (b)

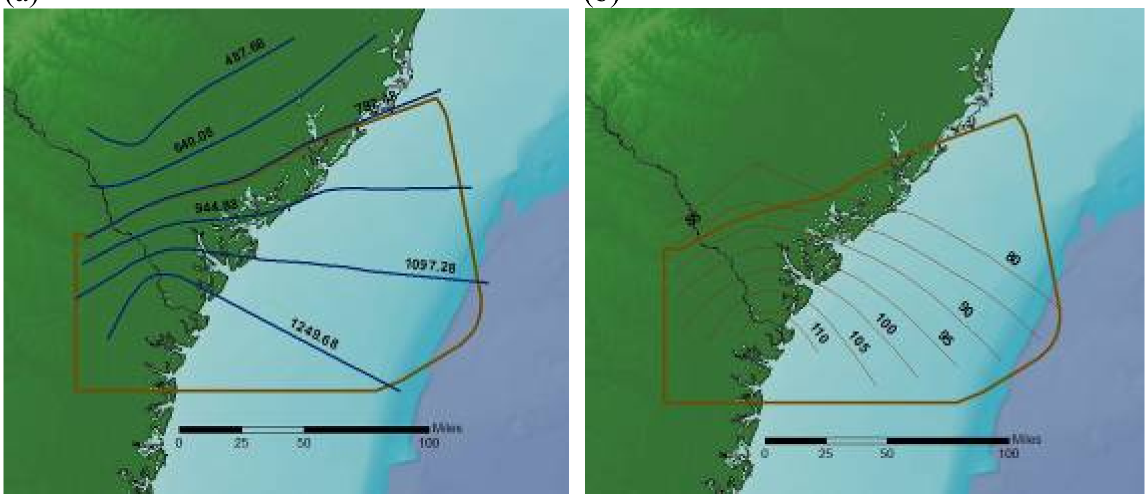


Figure 12. SGB Triassic sink (a) depth below sea level (m) to top, and (b) thickness (m) of Triassic sinks.

Table 1. Characteristics of potential sink intervals in Lightsey well.

TOP (ft)	BOTTOM (ft)	THICKNESS (ft)	LITHOLOGY
3450	3470	20	sand
7910	7930	20	sand
8440	8460	20	sand
7505	7565	60	diabase
8590	8620	30	diabase
9220	9250	30	diabase
9290	9315	25	diabase
9480	9530	50	diabase
	total sand > 15% porosity		60 ft
	total diabase >15 % porosity		195 ft

Interestingly, not all the sink intervals identified by Dr. Temples are composed of sedimentary rock. Two of the intervals are in basaltic igneous rock (sills) injected between layers of sediment during infilling of the SGB basin. Porosity estimated from the geophysical log is over 15 percent. Permeability was assigned a value of 100 millidarcys (md). A copy of the complete report received from Dr. Temples in appendix A.

Information on the geometry, composition, and thickness of Upper Cretaceous-age Tuscaloosa- and Atkinson-equivalent sink (figures 11 and 13) comes from geophysical logs of wells drilled during limited oil and gas exploration on the coastal plain, as well as onshore and offshore stratigraphic test wells (Brown et al., 1979; Scholle, 1979). Interpretations made from published maps and cross sections (Gohn et al., 1978; Renkin et al., 1989) show that depth to the top of the Tuscaloosa and Atkinson equivalents increases to the south and east, from 700 m near the Georgia–South Carolina border to more than 1,200 m at the coast near the Georgia–Florida border (fig. 12a). Greatest depths follow a southeasterly trend along the axis of the southeast Georgia embayment. Geophysical logs (Gohn et al., 1980; Renkin et al., 1989) indicate sand thicknesses as great as 50 m within and along the northern flank of the embayment (fig. 12b). Coast-parallel thickness trends suggest deposition of the Upper Cretaceous sediments in transgressive strandplain, barrier-island, or destructional deltaic systems.

There are few measured values of porosity or permeability within Tuscaloosa- and Atkinson-equivalent strata on the southern Atlantic Coastal Plain. Porosities reported for onshore wells by Temples and Waddell (1996) range from 26 to 36 percent. Porosities measured in stratigraphically equivalent units on the Georgia continental shelf were at the lower end of this range (Scholle, 1979). We chose to use a representative value of 27.5 percent in this study. The permeability calculated for these strata in regional groundwater modeling studies is 3,000 md (Barker and Pernik, 1994), within the range of published site-specific measurements of 1,000 to 6,000 md (Temples and Waddell, 1996) and higher than measurements of 1 to 1,000 md made on finer grained correlative strata beneath the Georgia continental shelf (Scholle, 1979). We assumed a representative permeability of 3,000 md throughout the southeast Georgia area.

(a) (b)

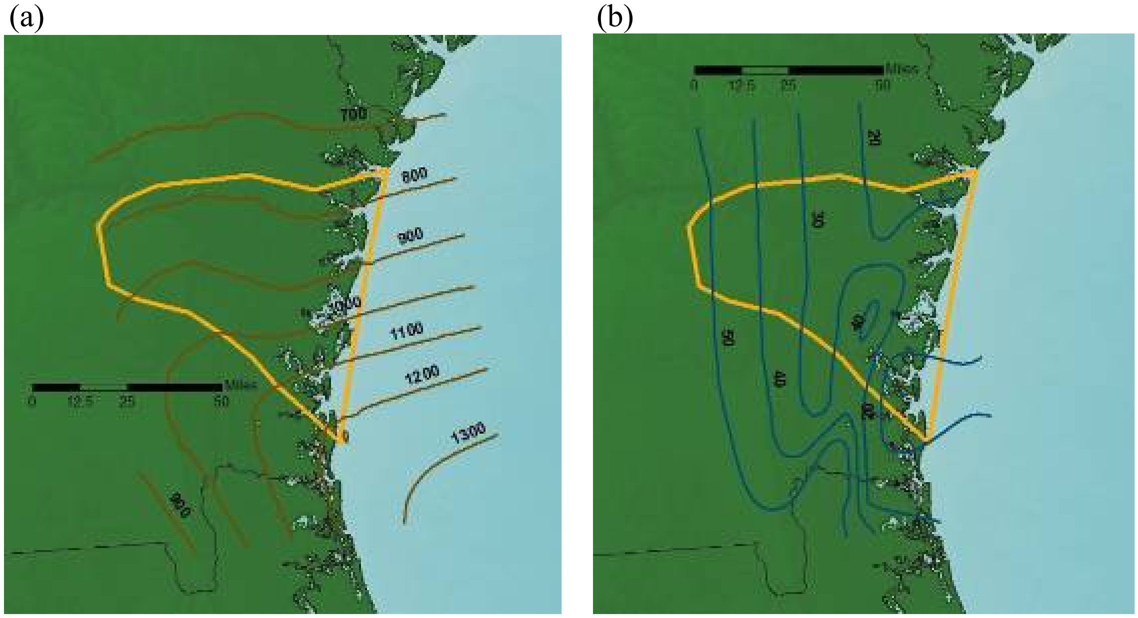


Figure 13. SGB Tuscaloosa\Atkinson Formations data in Georgia (a) depth below sea level (m) and (b) thickness (m).

The Tuscaloosa and Atkinson Formations beneath the Georgia Coastal Plain are considered to be part of the Black Warrior River (A4) aquifer, the basal and most extensive aquifer of the Southeastern Coastal Plain aquifer system (Renkin et al., 1989; Barker and Pernik, 1994). In general, Georgia's counties bordering the Atlantic Ocean are underlain by Black Warrior River aquifer strata containing groundwater with dissolved-solid concentrations greater than 10,000 mg/L, whereas more inland counties are underlain by strata containing fresher water (Miller, 1990).

Atlantic Subseafloor Sinks

Offshore geologic storage of CO_2 is fundamentally similar to onshore storage in terms of geological considerations (reservoir characteristics and trapping mechanisms). However, offshore settings involve initially higher pressures (beneath the water column) and lower temperatures at the seafloor, both of which favor denser CO_2 phases throughout subseafloor storage depths when compared with terrestrial settings. That is, CO_2 will always be denser at a given depth below sea level than in an onshore setting at a similar depth below a zero elevation land surface. Because much of the intent of drilling to great depths in terrestrial settings is to achieve dense CO_2 phases (and supercritical-phase properties) offshore operations may have reduced drilling costs. Absolute costs for drilling offshore from the Carolinas are unavailable but would be important for weighing the economic impact of the offshore sinks presented here.

It is important to note that offshore activities discussed here involve injections at hundreds to thousands of meters below the seafloor and should not be misinterpreted to include injection into (dissolution into) circulating seawater. Some researchers think that shallow subseafloor depths (< 300 m) are sufficient for permanent CO_2 storage in deep marine environments (> 3.5-km water depth; House et al., 2006). However, the shallow sedimentary environment can become unstable as a result of the release of gas from shallow gas hydrates (Lee et al., 1993) owing to pressure and temperature perturbations that may be introduced by drilling and injection. Furthermore, the logistics of transporting CO_2 many hundreds of kilometers offshore to the appropriate water depths (> 3 km or 1.9 mi) for storage in shallow sediments described by House et al. (2006) are likely to make such activity uneconomic. In contrast, we present below potential storage sites below the continental shelf in water depths between 50 and 1,000 m (165 and 3,500 ft) (fig. 14).

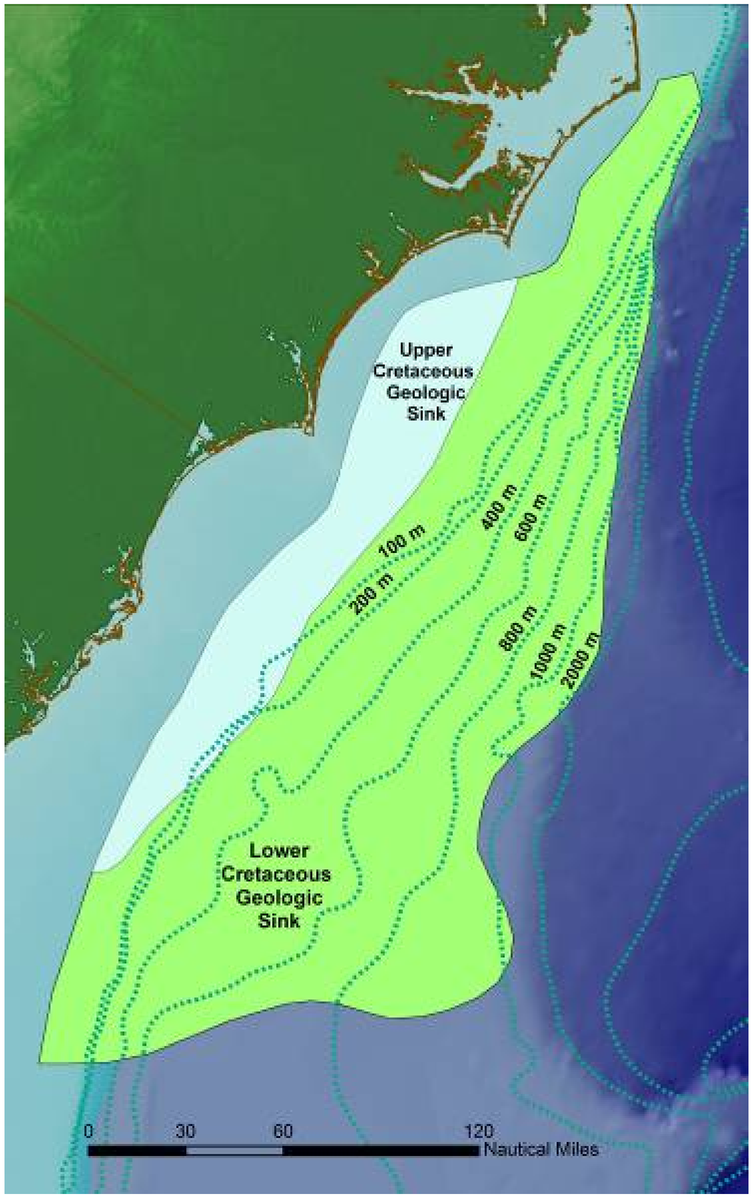


Figure 14. Upper and Lower Cretaceous Atlantic subseafloor sinks (modified from Hutchinson et al., 1996, 1997). Contoured water depth (m) shown in blue dashed lines (irregular contour interval). Depth from sea level to seafloor increases with darker shades of blue.

The potential sink (reservoir) units are the Upper and Lower Cretaceous strata beneath the seafloor located between 25 and 175 km (15 and 110 mi) offshore of the Carolinas. The Lower Cretaceous sink is Unit 120. A second, less-extensive sink is Upper Cretaceous-age Unit 90. Both units 90 and 120 have variable composition, composed of fine- to coarse-grained sediments. The deeper and more extensive Unit 120 extends over 15,000 km^2, ranging in depth from 700 to 3,200 m (2300–10,500 ft) below the seafloor (fig. 15a). Unit 120 has an extremely variable thickness, ranging from 10 (landward side) to 1,700 (seaward side) m in thickness (fig. 15b).

(a) (b)

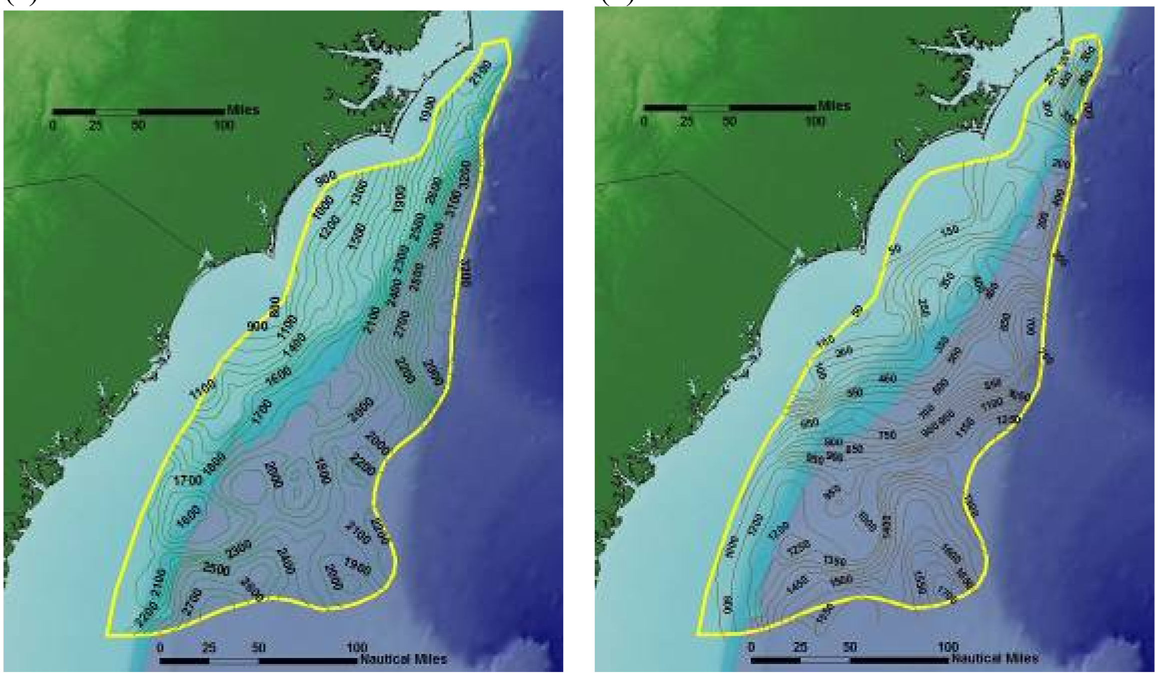


Figure 15. Offshore Atlantic Unit 120 (Lower Cretaceous): (a) depth below seafloor to top of unit (m); (b) contoured thickness (m). Contour data source: Hutchinson et al., 1997.

The shallower offshore Unit 90 extends over 8,000 km^2, ranging in depth from 200 to 1,000 m (66—3,300 ft) below the seafloor (fig. 16a). Thickness for Unit 90 ranges between 75 and 515 m (250 and 1,700 ft) (fig. 16b). Usable thicknesses for both prospective offshore sinks might be less than the maximum thicknesses shown.

(a) (b)

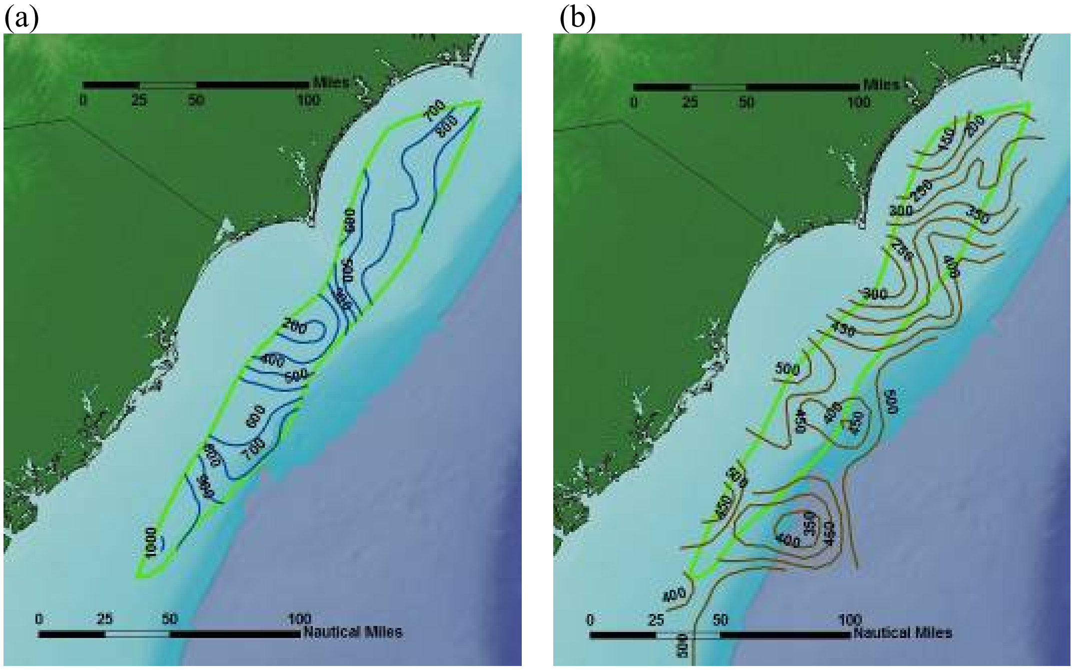


Figure 16. Offshore Atlantic Unit 90 (Upper Cretaceous): (a) depth below seafloor to top of unit (m); (b) contoured thickness (m). Contour data source: Hutchinson et al., 1997.

Owing to the absence of historic or present hydrocarbon production in the reservoirs offshore of the southern Atlantic margin, few detailed data are available for rock properties. However, porosity and permeability data applicable to Units 90 and 120 may come from several possible sources: (1) core analyses from COST well GE-1, (2) oil wells drilled offshore north of Hatteras in Baltimore Canyon Trough, and (3) an analogous area offshore northwestern Africa in the Senegal Basin (fig. 2), in which oil and gas exploration began in the late 1990's (Davison, 2005). For the purpose of preliminary scoping, we used a porosity of 20 percent and a permeability of 100 md to estimate capacity of the subseafloor sinks. This is an oversimplification of the geologic environment of this setting, but it allows for order-of-magnitude capacity estimations.

The shallowest, potentially effective geologic seal for trapping CO_2 lies between 200 (landward side) and 2,000 m (660-6600 ft) below the seafloor (Unit 80; Hutchinson et al., 1997). Because Unit 80 is the first good seal encountered below the seafloor, CO_2 cannot be stored at shallower depths in these sinks. Fine-grained, low-permeability horizons (Units 105 and 80) completely overlie each of the subseafloor sinks, providing a seal between sink horizons and the seafloor.

The offshore geothermal gradient is expected to be similar to an onshore gradient because the continental crust extends offshore approximately 150 km (93 mi) (figures 17, 18). Deep Sea Drilling Project (DSDP) and petroleum industry data along the Atlantic margin suggest a temperature gradient of 1 to 2 °F per 100-ft depth (~25 °C/km) (Costain and Speer, 1988). Temperatures at the seafloor offshore the Atlantic coast are cold (0 °C or 32 °F), but if the geothermal gradient is similar to that of nearby onshore terrestrial settings, then the critical temperature of 31 °C (88 °F) will be reached at approximately 1.2 km (0.75 mi) below the seafloor. Temperature in the Hatteras Lighthouse well no. 1 at Cape Hatteras at 3,048 m (10,000 ft) is 77 °C (170 °F), suggesting a gradient of 1.7 °F per 100 ft. (~25 °C/km). Borehole temperature data from seven wells along the southern coast of North Carolina (Lambe et al., 1980) indicate supercritical temperatures around 1,000 to 1,300 m (3280 to 4265 ft) below the seafloor.

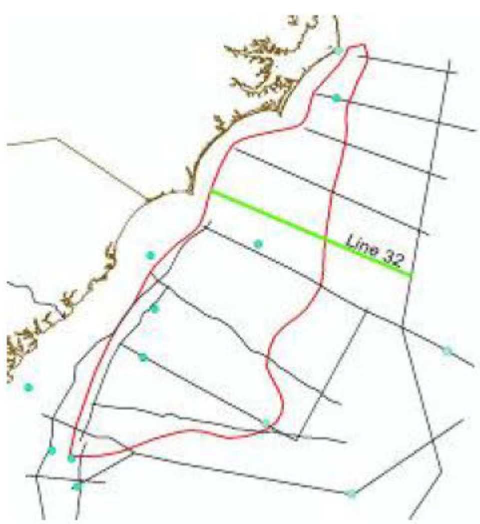


Figure 17. Location of USGS referenced (Hutchinson et al. 1996, 1997) seismic lines. Cross section in figure 18 is along line 32 offshore from Cape Fear, NC.

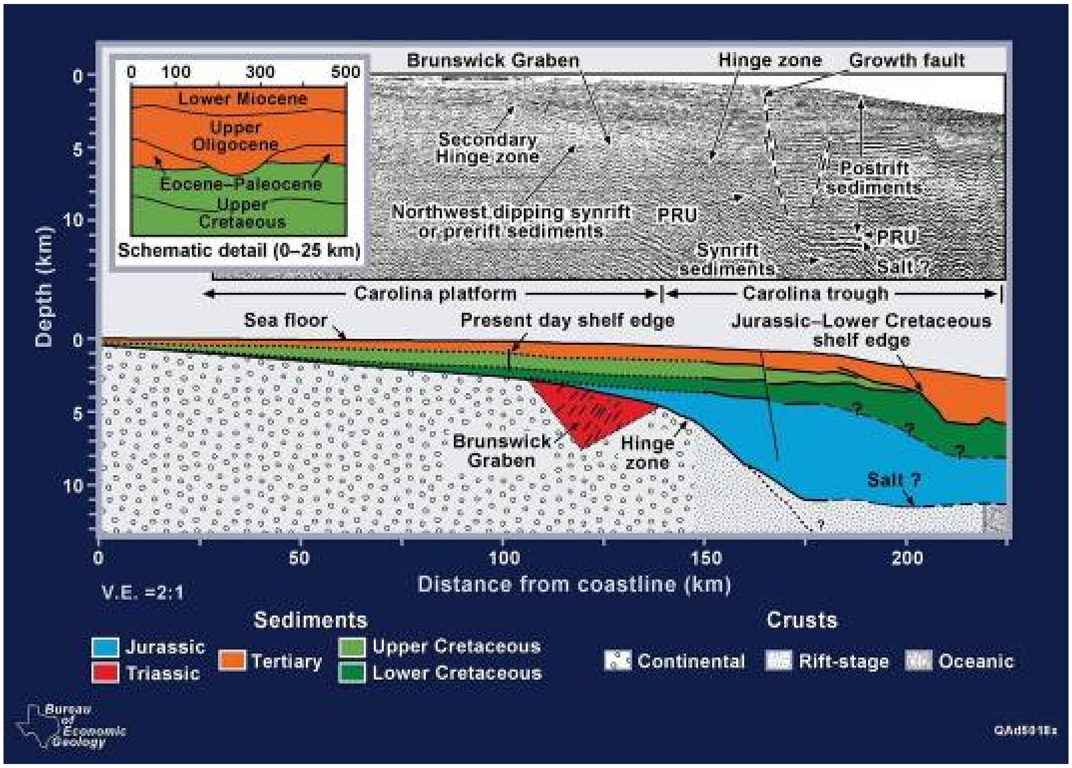


Figure 18. Schematic cross section along seismic line 32 shown in fig. 16. Modified from Grow et al. (1988); Hutchinson et al. (1982); and Hutchinson et al. (1997).

Important points illustrated by the cross section shown in fig. 18 include:

- Strata dip and thicken seaward.
- In the absence of an onshore/nearshore Triassic rift basin, post-rift sediments are not thick enough to serve as geologic sinks. Note that the Triassic age Brunswick graben is analogous to the onshore Mesozoic rift basins, but is seaward of the continental crust, offshore from the present day continental shelf edge.
- Top of Upper Cretaceous strata within 25 km (16 mi) of the coast may have been scoured during deposition of Tertiary age units and therefore might not have good seal integrity.
- The edge of North American continent crust lies approximately 150 km (93 mi) offshore from Cape Fear, North Carolina, which is underneath ~1500 m (~4900 ft) of water.

Regarding pressures, a typical terrestrial (onshore) hydrostatic gradient (pressure increase per foot of depth increase) for freshwater is 0.0097 MPa/m (0.433 psi/ft). In marine settings, a typical saltwater (88,000 ppm TDS) hydrostatic gradient is slightly higher: 0.0105 MPa/m (0.465 psi/ft). The impact is that the critical pressure for CO_2 (7.37 MPa, 1070 psi) may be encountered approximately 60 m (197 ft) shallower for offshore settings than for onshore (e.g., 700 m (2297 ft) below sea level versus 760 m (2493 ft) below a zero elevation land surface). This is not a dramatic difference, considering the total drilling depths involved. Furthermore, water becomes more saline with depth in terrestrial settings, approaching and potentially exceeding marine salinities. Thus, the difference in depth to critical pressure is likely to be a maximum value.

Temperature-pressure regimes in the potential offshore geologic sinks are such that injected CO_2 would be very dense, but formation temperatures will not be warm enough for the supercritical conditions typically sought after in terrestrial environments. Yet successful CO_2 storage in subseafloor geologic environments can occur at pressures and temperatures below supercritical conditions. In such environments, the relatively cold temperatures and high pressures result in higher CO_2 densities (>900 km/m^3, 56 lb/ft^3, when compared with typical terrestrial storage conditions. A smaller volume is thus required for comparable storage efficiency in subseafloor versus subterranean sinks.

The reservoir and sealing capacity of the described units to bouyant CO_2 is essentially unknown in offshore Atlantic settings, but they should perform similarly to tested subseafloor storage examples. The best-documented offshore storage example is related to activity in the Sleipner gas field located in the Norwegian North Sea, which is operated by Statoil. There CO_2 has been injected into an exceptionally porous and permeable, poorly consolidated sand horizon 800 m (2625 ft) below the seafloor in 75 m (246 ft) of water. The geologic sink used (Utsira Formation) is 200 m (656 ft) thick and extends over 25,000 km^2 (9652 mi^2). The overlying finer grained silts and shales are an effective top seal. It is thought that the storage capacity may be on the order of 100 times the annual European CO_2 emissions from power plants (Statoil, 2004). Since 1996, the Utsira Formation has safely received and contained approximately 1 million metric tons of CO_2 per year (Statoil, 2004).

Three caveats to offshore operations have been identified but remain to be considered in further detail: (1) the presence of freshwater below the continental margin at depths of over 1 km beneath the seafloor (Kohout et al., 1988), (2) the potential displacement (due to CO_2 injection) of subseafloor (geologic) water within potential reservoirs and discharge at the seafloor, and (3) the hazard of encountering shallow gas hydrates during pipeline and drilling operations on the continental shelf. The first issue concerns water quality and the anticipation of eventual utilization of offshore freshwater resources. The potential displacement of geologic water beneath the seafloor is of concern because potential discharge at the seafloor or the shelf edge or on the continental slope may generate conditions favorable to sediment dispersal (such as slumping or erosion). The drilling hazard of encountering hydrates is well known, and their distribution is known to some degree (e.g. fig. 19). Pipeline and well locations would need to rely on updated maps of hydrate distribution and may involve detailed surveys to further minimize risks. Expertise for these types of surveys is widespread, and hydrate studies are in a mature phase.

Figure 19. Location of known hydrate deposits offshore from the U.S. Atlantic east coast. Hydrate data modified from Dillon et al. 1995.

At present, the only subseafloor geologic storage site for CO_2 is operated by Statoil in the Norwegian North Sea. The sinks identified offshore from the Carolinas are not as well characterized as the North Sea example and would require investigation to determine suitability and to refine capacity estimates. Legal, regulatory, and policy implications of subseafloor geologic storage of CO_2 are unresolved at this time. However, in November 2006, a resolution was adopted by members of the 1996 Protocol of the London Convention to "establish the legality of storing CO_2 in sub-seabed geologic formations." Guidelines for scientific assessment of the potential for subseafloor CO_2 storage are due to be finalized and presented to the international community soon (IEA, 2006).

Sinks Farther from the Carolinas

Because geology within the Carolinas is generally unsuitable for long-term storage of CO_2, it is necessary to look outside the states for potential geologic sinks. This analysis is focused only on the geologic suitability of out-of-state sinks and does not address policy or environmental aspects of interstate transport. Potential geologic sinks in Tennessee and Kentucky/West Virginia (Mt. Simon and Knox, respectively) (fig. 9) lie within the Appalachian Plateau province of the Appalachian Mountains. Preliminary analysis indicates that the Tuscaloosa Group of southwestern Alabama and the panhandle of Florida (fig. 9) are also a potential sink for CO_2 geologic storage.

Mt. Simon Formation in Tennessee

The late Cambrian-age Mt. Simon Formation (fig.9) is a quartz arenite sandstone (Driese et al., 1981). Depth to base of Mt. Simon sink ranges from 1,200 to 2,400 m (fig. 20). Mt. Simon data in Tennessee are from an unpublished work compiled by Advanced Resources International (ARI). Thickness of Mt. Simon across entire areas is estimated by ARI to be 100 ft. A copy of data received from ARI is contained in appendix B.

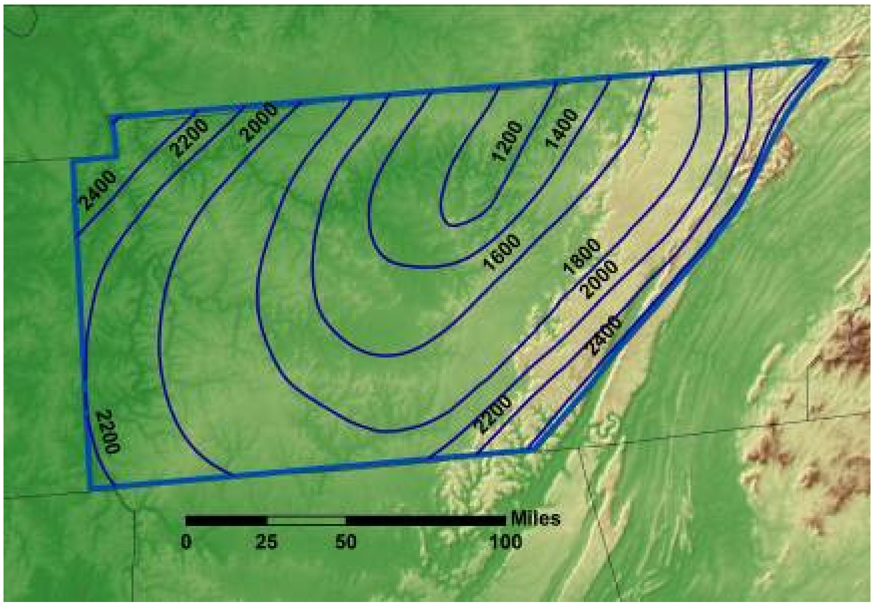


Figure 20. Base of Mt. Simon Formation in meters.

Knox Group in Kentucky and West Virginia

Since the early 1960's, hydrocarbons (primarily gas) have been produced from Knox Group paleotopographic highs along the postrift unconformity and from fractured dolomites and sandy interlayers (Baranoski et al., 1996). Although the potential for future natural gas production from the Knox Group is great within the Rome Trough of eastern Kentucky and West Virginia (Baranoski, 1996), areas within almost the entire Knox Group Play show great potential for storage of greenhouse gasses. The Knox Group Play is more expansive to the northeast and tapers to the southwest following the western boundary of the Appalachian Plateau physiographic province (fig. 21).

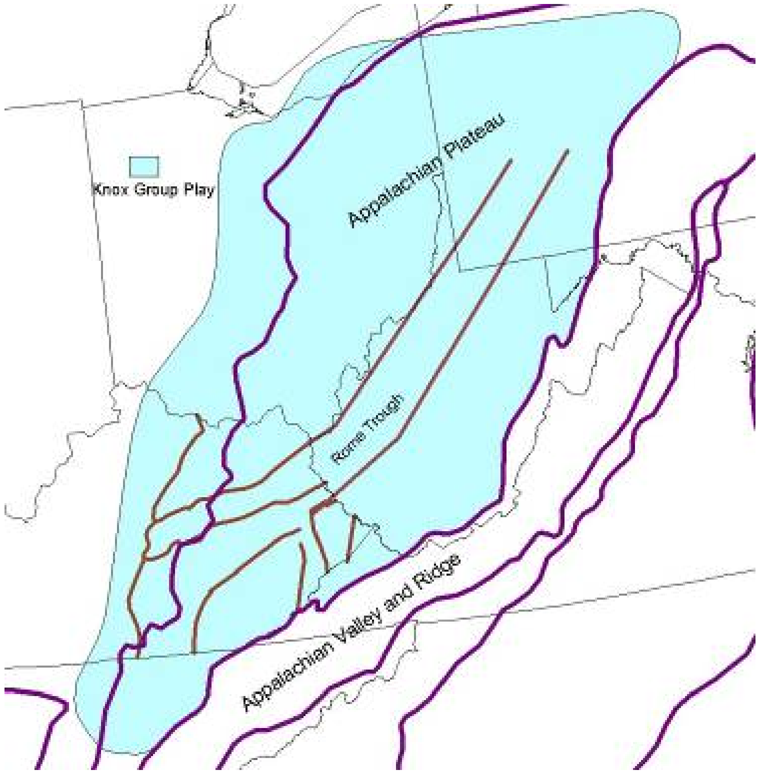


Figure 21. Knox Group play, Appalachian Plateau, southern Appalachian Mountains. Modified from Baranoski et al. (1996) and Shumaker (1996).

The Cambrian portion of the Knox Group is a gray, finely crystalline dolomite in which secondary porosity has been enhanced by recrystallization (Rodgers, 1953; Read, 1989; Milici, 1996). In the Southern and Central Appalachians, Cambrian subunits of the Knox are stacked peritidal carbonate cycles from 3 to 15 ft thick. Cycles, lime mudstone at the base, coarsen upward into pelletal oolitic grainstones, flat-pebble conglomerates, and stromatolites (Read, 1989).

The Ordovician portion of the Knox Group contains peritidal carbonates in the west to shallow, subtidal, open-marine or biohermal shelf-edge deposits in the east (Read, 1989). A Knox Group facies in Tennessee contains significant secondary porosity owing to diagenetic dolomitization and formation of solution-collapse breccias. These Ordovician-aged rocks in Tennessee contain Mississippi Valley-type sphalerite mineralization (Montanez, 1994).

Average value of porosity calculated from log analysis of the pay zone from three producing fields in Kentucky is 8 percent (10 logs evaluated), 9 percent (9 logs evaluated), and 4 percent (2 logs evaluated). These fields reported between 20 and 700 Mcf initial gas production. Overall, the average porosity for horizons within the Knox Group Play ranges from 3 to 20 percent, averaging 9 percent. Permeability in the Rose Run Sandstone ranges from 0.01 to 198 md and averages 5 md (Baranoski et al., 1996).

We mapped the elevation of the top of the Knox Group by combining published structure contours (Baranoski et al. 1996) with those inferred from a map of basement structure (Shumaker 1996). We then calculated depth to top of the formation by subtracting gridded elevation from surface topography (90-m digital elevation models

[DEM's] generated from Shuttle Radar Topography Mission [SRTM] data [http://srtm.usgs.gov/data/obtainingdata.html or http://srtm.csi.cgiar.org/]). Depth below ground to the top of the Knox Group sink ranges from 800 m in eastern Kentucky to 2,600 m in southern West Virginia (fig. 22a).

The entire Knox Group is quite thick, ranging from 305 to over 1220 m (1,000 to over 4,000 ft) in thickness within the play (Baranoski et al., 1996). Thickness isopachs increase to the northeast in West Virginia and southwestern Pennsylvania and to the southwest toward Tennessee. Thickness in the Knox Group sink ranges from 500 to 1,200 m (1640 to 3940 ft) (fig. 22b).

(a) (b)

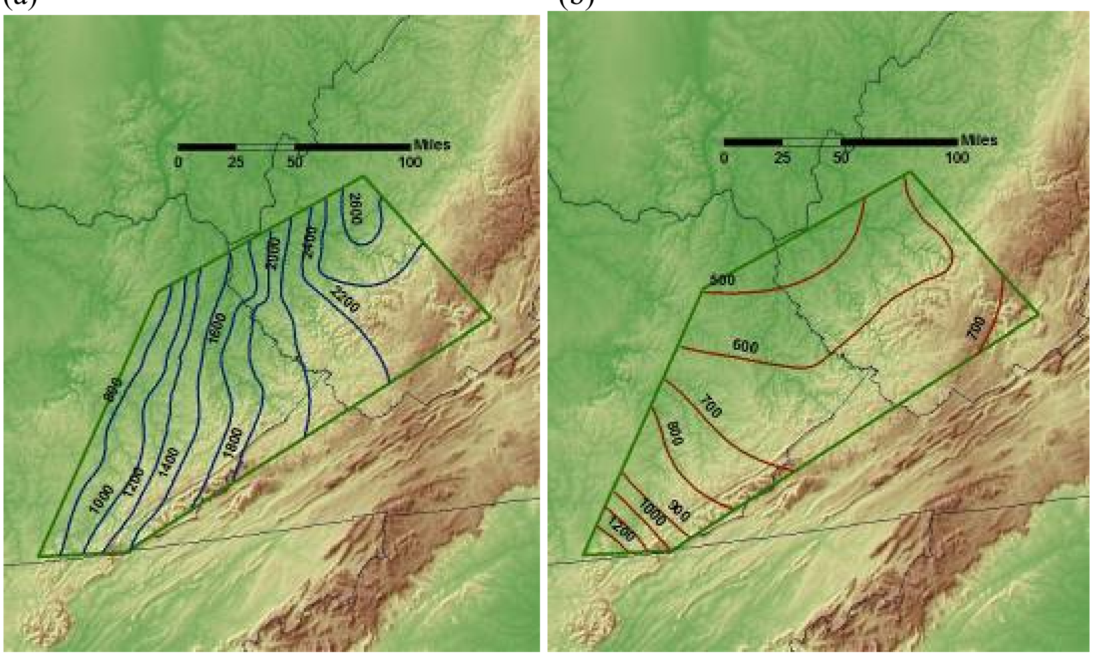


Figure 22. Potential Knox Group geologic sink, (a) structure contour on top of Knox (m), and (b) thickness of Knox (m).

<u>Tuscaloosa Formation in Alabama and Florida</u>

Preliminary analysis indicates that the Tuscaloosa Group of southwestern Alabama and the panhandle of Florida (fig. 9) is a potential host for CO_2 geologic storage. Sandstones in the lower part of the Tuscaloosa, including the informally named Massive and Pilot intervals, are the most favorable host strata. These units have been interpreted to represent a transgressive sequence that includes fluvial, deltaic, and coastal barrier or strandplain environments (Mancini et al., 1987).

The primary sources of information on the geometry, composition, and thickness of the Lower Tuscaloosa strata are geophysical logs of wells drilled for oil and gas exploration and production, as well as produced water and industrial waste disposal. Interpretations made from published maps and logs (Miller, 1979; Mancini et al., 1987; and Renkin et al., 1989) and unpublished information provided by the Florida Geological Survey (pers. comm., 2006) show that depth to the top of the lower Tuscaloosa sand intervals increases from zero where lower Tuscaloosa equivalents crop out northeast of the study area to more than 2,500 m (8200 ft) southwest of Mobile Bay (fig. 23). These strata dip to the south-southwest toward the axis of the Mississippi embayment, transitioning to a more westerly dip component farther northward. Thickness of dominantly sandy lower Tuscaloosa strata can approach or exceed 100 m (328 ft). Contoured maps depict a general trend of thickness increasing southwestward from 10 m (33 ft) or less in the northeastern part of the subject area to more than 70 m (230 ft) along the Florida shoreline and southwest of Mobile Bay (fig. 23).

There is relatively little published information on the porosity and permeability distribution within lower Tuscaloosa Group strata. Lower Tuscaloosa porosities reported for Alabama wells by Tucker and Kidd (1973) range from 30 to 33 percent, slightly higher than values of 25 to 30 percent quoted for Tuscaloosa brine-injection wells in Jay field (Florida Geological Survey, pers. comm., 2006). The conservative, representative value that we chose for this study is 27.5 percent. Quoted Lower Tuscaloosa permeabilities range from 50 to 1,000 md in Alabama (Tucker and Kidd, 1973) and from 500 to 1,000 md in lower Tuscaloosa Massive unit injection wells in Florida's Jay field (Florida Geological Survey, pers. comm., 2006). We assumed a representative permeability of 750 md throughout the Tuscaloosa area. SECARB research groups will be collecting additional data for the Tuscaloosa in Alabama and Mississippi beginning in spring of 2008.

The Lower Tuscaloosa Group is part of the Black Warrior River aquifer, the basal and most extensive aquifer in the Southeastern Coastal Plain aquifer system (Renkin et al., 1989; Barker and Pernik, 1994). At depths suitable for CO_2 storage, dissolved-solid concentrations of pore water exceed 10,000 mg/L TDS (Miller, 1979; Barker and Pernik, 1994).

(a) (b)

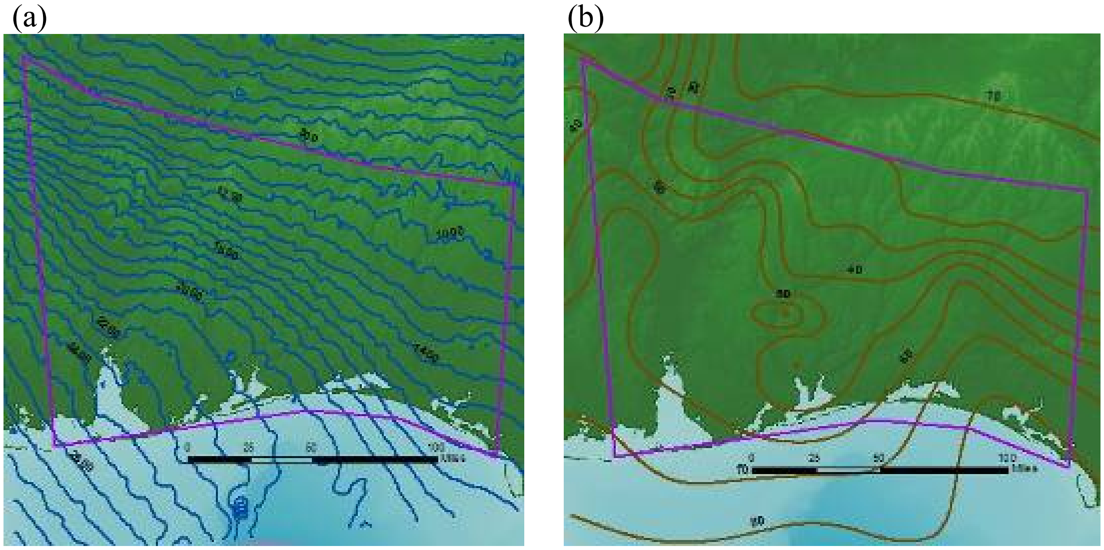


Figure 23. Tuscaloosa sink data: (a) structure contours (m) indicating depth to top of Tuscaloosa sink in Alabama and Florida. (b) isopach (thickness in m) for the same sink.

Estimates of Sink Capacity and Pipeline Costs

Geologic units underlying most of North and South Carolina do not meet minimum suitability criteria necessary for long-term storage of CO_2. Hence, in order to match potential sources of CO_2 with potential sinks, CO_2 will have to be transported before it can be injected into the subsurface and isolated from the atmosphere and freshwater resources.

Massachusetts Institute of Technology (MIT) Laboratory for Energy and the Environment has developed a Carbon Management Geographic Information System (GIS) tool that utilizes ArcGIS© (software developed by Environmental Systems Research Institute) to evaluate CO_2 sources and sinks. This section contains the geologic sink capacity estimates and GIS analysis of the pipeline calculations completed by the Carbon Capture and Sequestration Technologies Program at MIT. Multiple pipeline scenarios are presented in order to provide CO_2 transport estimates to all potential geologic sinks. The MIT methodology is provided in appendices C-1, C-2, and C-3. Additional MIT data tables and plots are provided in Appendix D.

Capacity

MIT capacity estimates are based on limited and generalized data sets, which are primarily from published literature. More accurate estimates of capacity for the specific geologic sinks included in this study will require site-specific, detailed geologic investigations.

The MIT methodology assumes that if the suitability criteria (1) continuity and integrity of an overlying seal and (2) pressure and temperature conditions sufficient to maintain CO2 at high density are met, the CO_2 storage capacity of a saline reservoir can be calculated using the following formula:

$$Q_{aqui} = V_{aqui} * p * e * \rho_{CO2} \quad (1)$$

where Q_{aqui} = storage capacity of entire reservoir (Mt CO_2)

V_{aqui} = total volume of entire reservoir (km^3)

p = reservoir porosity (%)

e = CO_2 storage efficiency (%)

ρCO_2 = CO_2 density at reservoir conditions (kg/m^3)

If accurate spatial data are available for a reservoir, then the reservoir volume used in equation 1 can be calculated as an integral of the surface area and thickness of the reservoir:

$$V_{aqui} = \sum_i S_i T_i \quad (2)$$

where S_i is the area of the raster cell and

T_i is the thickness of the cell

The term "CO_2 storage efficiency" refers to the fraction of the reservoir pore volume that can be filled with CO_2. For a saline reservoir in which CO_2 can be trapped by a physical barrier (overlying seal), the storage efficiency is estimated at 2% (Holloway, 1996).

Estimates of storage capacity of the potential geologic sinks located in (1) South Georgia Basin (SGB), (2) offshore Atlantic subseafloor (units 90 and 120), (3) Tennessee (Mt. Simon), (4) Kentucky and West Virginia (Knox), and (5) Alabama and Florida (Tuscaloosa) are summarized in table 2.

Table 2. MIT estimates of CO_2 storage capacity.

POTENTIAL SINK	CAPACITY ESTIMATES[1] (Gt)
SGB Triassic units Atkinson-Tuscaloosa Cape Fear	~15
Offshore Sinks Unit 120 Unit 90	 ~178[2] ~16[2]
Hatteras Area	n.a.[3]
Mt. Simon	~3
Knox	~32
Tuscaloosa	~10

Notes:
1. CO_2 storage efficiency estimated as 2 percent and all the aquifers are assumed closed.
2. CO_2 density in the offshore sites assumed to be 700 kg/m^3.
3. Detailed data are not available.

<u>Pipeline Cost Methodology</u>

Part of the source-sink matching process requires estimates of the cost of CO_2 transport to a specific geologic sink. For purposes of this discussion, we focused on the potential for transportation by pipeline. Estimates of pipeline costs for this study were conducted by the MIT Laboratory for Energy and the Environment in late 2006. Pipeline cost estimates (in 2006 dollar equivalents for materials) include pipeline construction, right-of-way acquisition, and operation. Cost estimates for CO_2 pipeline construction are based on cost data for natural gas pipelines. This may have resulted in an underestimate of costs to build CO_2 pipelines because of the greater CO_2 wall thickness required to contain supercritical (high pressure and temperature) CO_2. Neither the cost of capture/separation at the plant nor the cost of compression and injection at the CO_2 storage site are included. These elements are beyond the scope of this assessment, which is to match sources with sinks and provide a relative index of cost escalation as the distance between sources and sinks increases.

MIT started this process using data for the CO_2 generated by fossil-fuel power plants in North and South Carolina. They used the USEPA eGRID 2002 (data for 2000) database to estimate the adjusted CO_2 emissions and annual flow rates, assuming 80 percent operating factor and 90 percent capture efficiency. Owing to economies of scale, they included only power plants with a design capacity greater than 100MW (fig. 24 and table 3).

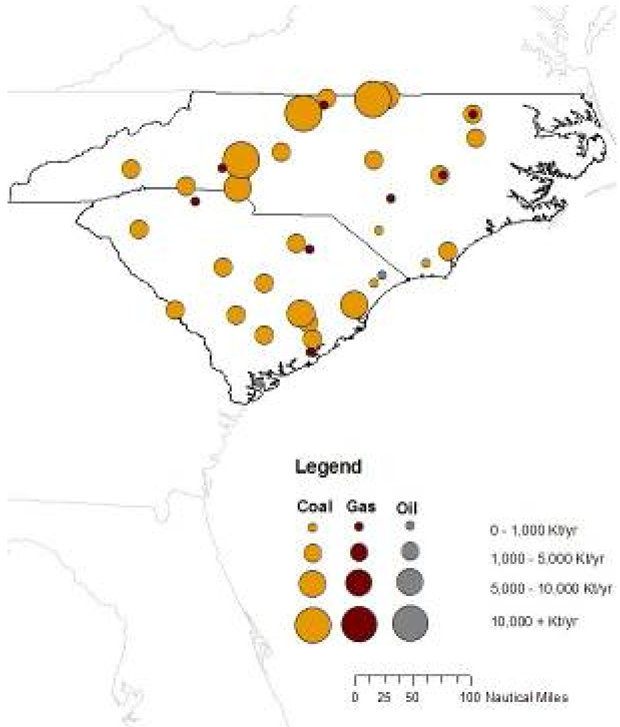


Figure 24. Power plant data used in MIT pipeline cost estimates.

Table 3. Fossil-fuel power plants by fuel type (design capacity>100MW)

FUEL TYPE	Coal-Fired PP	Gas-Fired PP	Oil-Fired PP	Total
Numbe of Power Plants (PP)	29	9	2	40
Total Design Capacity (MWe)	21,651	5,565	229	27,446
2000 Average Operating Factor[a]	0.63	0.05	0.02	0.51
Actual 2000 Total CO_2 Emission (Mt)[b]	117	2	0	119
Adjusted Total Annual CO_2 Emission (Mt)[c]	153	32	3	188
Estimated 25-year CO_2 Flow (Mt)[d]	3,441	729	61	4,231

Notes: [a]Weighted (by design capacity) average operating factor
[b]eGRID published 2000 CO_2 emission based on actual plant operating factor
[c]Estimated plant CO_2 emission at 80% operating factor
[d]Estimated CO_2 flow rate assuming 90% capture efficiency

After identifying CO_2 sources in the Carolinas and using the geologic sink data provided by BEG, MIT workers evaluated source-sink matching over an assumed 25-yr project lifetime. They used a GIS method of matching sources and sinks that considers optimal pipeline route selection and capacity constraints of individual sinks. Because pipeline construction costs vary considerably according to local terrain, number of crossings (waterway, railway, highway), and the traversing of populated places, wetlands, and national or state parks, the group constructed a digital terrain map that allows ranking of these factors (fig. 25). MIT used the digital terrain map to generate a grid of transportation cost factor, which appears in figures 26 through 30.

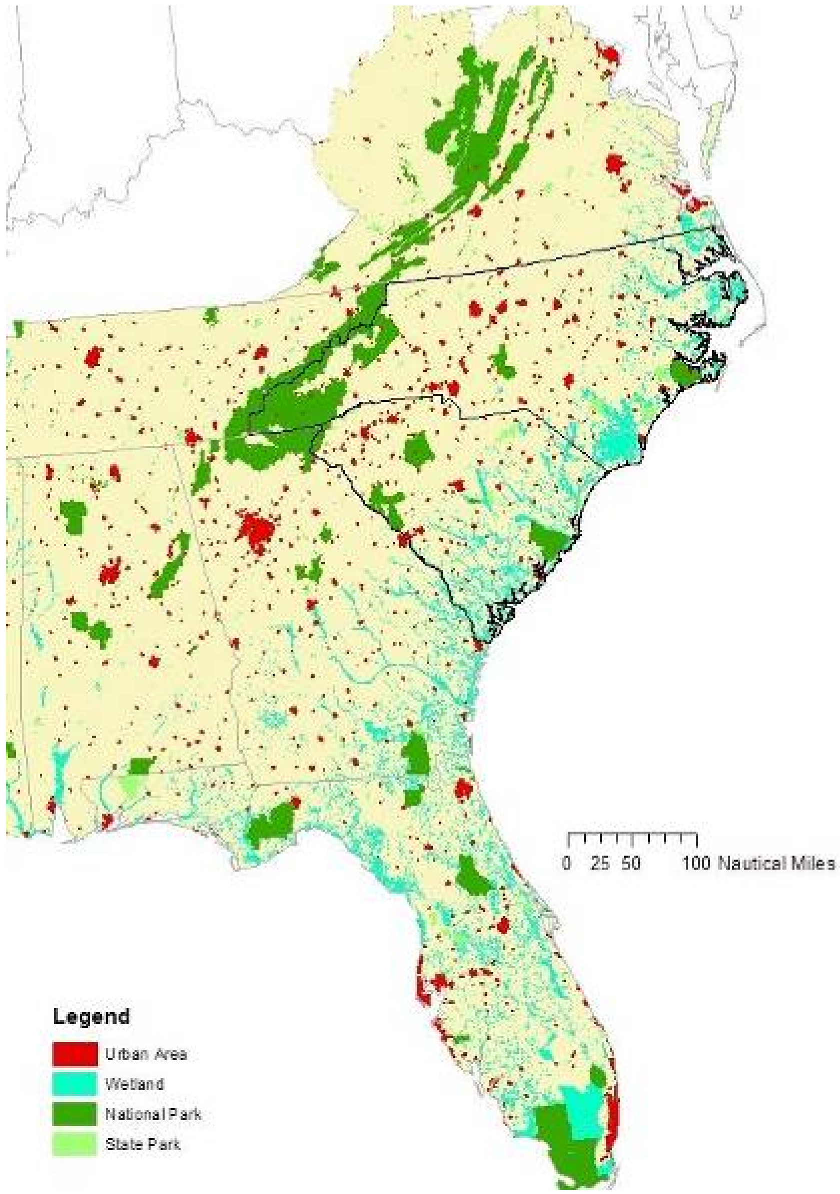


Figure 25. Terrain classification used in MIT pipeline cost estimates.

MIT generated pipeline-transport algorithms using the Carnegie Mellon University (CMU) correlation (McCoy, 2006). Because the MIT source sink matching program develops a minimum cost curve, it favors sinks that are closer to potential sources and automatically excludes more distant sinks. In order to obtain pipeline estimates for all potential sinks presented in this study, MIT used a multiple scenario approach that alternatively excluded nearby sinks so as to force utilization of more distant sinks. Following are constraints for the five possible scenarios:

- Scenario 1 includes all potential sinks,
- Scenario 2 considers all sinks except the Hatteras area,
- Scenario 3 considers all sinks except the Hatteras area and subseafloor Unit 90 (Upper Cretaceous) in order to force pipeline estimates for subseafloor Unit 120 (Lower Cretaceous),
- Scenario 4 excludes the Hatteras area, subseafloor Unit 90 (Upper Cretaceous), and SGB to force pipeline estimates for Mt. Simon sink,
- Scenario 5 excludes the Hatteras area, subseafloor Unit 90 (Upper Cretaceous), SGB, and Mt. Simon to force pipeline estimates for Tuscaloosa sink in Alabama/Florida.

Summaries of estimated costs (in 2006 dollar equivalents for materials) for pipelines between selected sources and potential target sinks are presented for each of the five scenarios (table 4). The pipeline construction costs are composed of two components, the basic pipeline construction cost, which is diameter-dependant, and the additional obstacle cost (independent of diameter), which is represented by the transportation cost factor grid shown in figures 26 through 30. The model output used to generate values in table 4 are summarized in Appendix E. Total power output (design capacity) of the plants served ranges from 25.8 gigawatts (GW) for Scenario 1 to 24.5 GW for Scenario 5. Total pipeline construction costs range from \$3.8 billion for Scenario 1 to \$4.3 billion for Scenario 5. Average transportation costs vary from \$3.56 to \$4.21 per metric ton of CO_2. The costs presented here are in 2006 dollar equivalents for materials.

Table 4. Estimated cost summary (in 2006 dollar equivalents for materials) for five sink scenarios (for power plants with transportation cost <10\$/t CO_2).

SINK OPTIONS	TOTAL CONSTRUCTION COST (BILLION \$)	TOTAL CO_2 STORED IN 25 YEARS (GT[1])	TOTAL DESIGN CAPACITY (GW)	AVERAGE COST (\$/TON CO_2)	AVERAGE DISTANCE[2] (km)	TARGET SINKS
Scenario 1	3.8	4.2	25.8	3.56	299	Hatteras, Knox, Unit 90, SGB
Scenario 2	3.8	4.1	25.3	3.63	322	Knox, Unit 90, SGB
Scenario 3	4.0	4.1	24.8	3.84	344	Knox, Unit 120, SGB
Scenario 4	4.2	4.0	24.5	4.17	370	Knox, Mt. Simon, Unit 120
Scenario 5	4.3	4.0	24.5	4.21	373	Knox, Unit 120, Tuscaloosa

[1]Gt = 1 billion metric tons
[2]Flow-rate-weighted-average pipeline distance

Costs for Sink Option Scenario 1 are lowest because only those potential sinks closest to the Carolinas power plants—Hatteras, Knox, Unit 90, and SGB—are utilized (table 4, fig. 25). Scenario 2 is may be more likely because it excludes the Hatteras sink; we do not think it is likely that there will be drilling allowed in the Cape Hatteras, NC area. The purpose of running MIT's GIS algorithms using scenarios 3, 4, and 5 was to obtain estimated costs for utilizing the more distant potential sinks—subseafloor unit 120, Mt. Simon, and Tuscaloosa—for geologic storage of CO_2.

Results from the individual source-sink matching hypothetical scenarios are summarized in the following sections and figures 26 through 30. Each section contains a map showing location of the power plants with a design capacity greater than 100MW (red triangles); the same power plants shown in fig. 24 and described in table 3 are used in all scenarios. The blue lines represent pipeline routes. The saline reservoir sinks are the same as those discussed in previous sections of this report with the exception of the South Georgia Basin. Recall from figure 11 that this area contains three partially overlapping saline reservoir horizons that are suitable geologic sinks. The three sink horizons are from shallowest to deepest the (1) Atkinson-Tuscaloosa (fig. 13 and GA in figures 26 through 30), (2) Cape Fear, and (3) Triassic-age intervals (SGB in figures 26 through 30). The transportation cost factor grid shown in figures 26 through 30 was generated from a combination of (1) land slope, (2) presence of absence of protected areas (populated areas, wetlands, State or National parks), and (3) crossings (waterway, highway, or railroad).

Source-Sink Matching for Pipeline Scenario 1

Scenario 1 used all potential sinks included in this study as possible locations for subsurface storage of CO_2 generated by power plants in the Carolinas with a design capacity greater than 100MW. The MIT optimal pipeline network solution for Scenario 1 (fig. 26) utilized the Knox, Hatteras, subseafloor unit 90, SGB, and GA sinks. CO_2 generated by most of the power plants in western North Carolina (NC) could be transported via pipeline across the Appalachian Mountains to the Knox sink. CO_2 generated by most of the power plants in eastern NC could be transported to the Hatteras sink. CO_2 from a few of the plants in southern NC and northeastern South Carolina (SC) could be transported to the subseafloor unit 90 sink. CO_2 from most of the power plants in SC could be sent to the South Georgia Basin (SGB and GA in fig. 26).

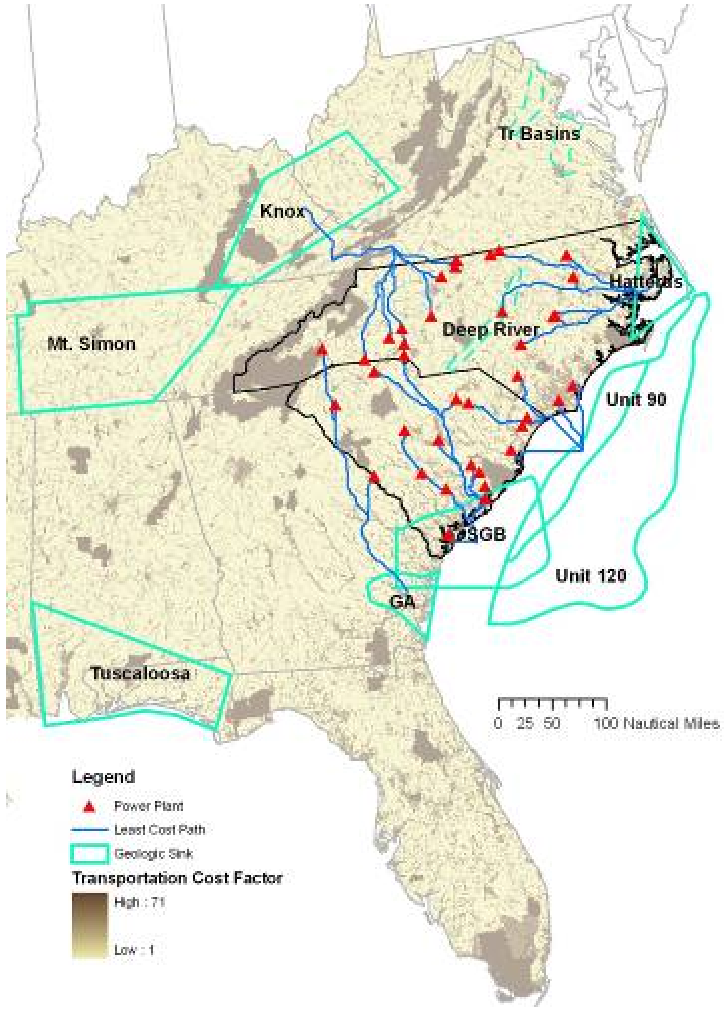


Figure 26. MIT Scenario 1 optimal pipeline network solution.

<u>Source-Sink Matching for Pipeline Scenario 2</u>

In this scenario all the potential sinks except for Hatteras were used as possible locations for subsurface storage of CO_2 generated by power plants in the Carolinas with a design capacity greater than 100MW. The MIT optimal pipeline network solution for Scenario 2 (fig. 27) utilizes the Knox, subseafloor unit 90, SGB, and GA sinks. The difference in Scenario 2 is that CO_2 could be transported to the unit 90 subseafloor sink rather than being transported to the Hatteras sink as in Scenario 1. CO_2 generated by most of the power plants in western NC could still be transported to the Knox sink. CO_2 from most of the power plants in SC could still be sent to the South Georgia Basin (SGB and GA in fig. 27).

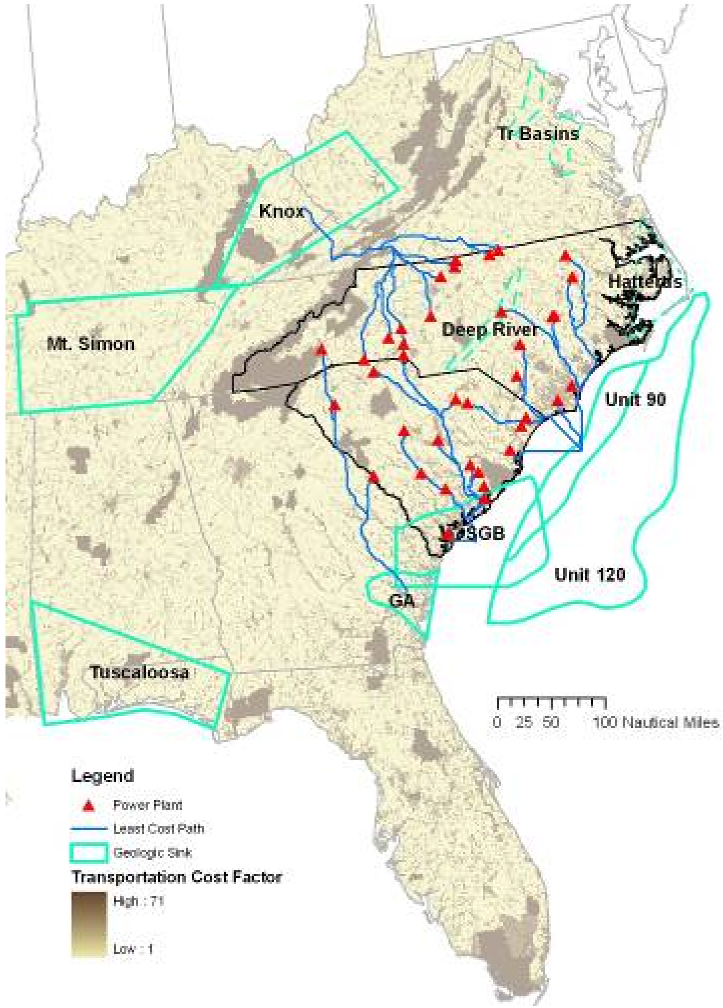


Figure 27. MIT Scenario 2 optimal pipeline network solution.

<u>Source-Sink Matching for Pipeline Scenario 3</u>

In Scenario 3 all the potential sinks except for Hatteras and subseafloor unit 90 were used as possible locations for subsurface storage of CO_2 generated by power plants in the Carolinas with a design capacity greater than 100MW. The MIT optimal pipeline network solution for Scenario 3 (fig. 28) utilizes the Knox, subseafloor unit 120, SGB, and GA sinks. The objective of this scenario was to force utilization of subseafloor unit 120, which would require a longer offshore pipeline and hence increase cost. Otherwise the transport network solution matches the one in Scenario 2.

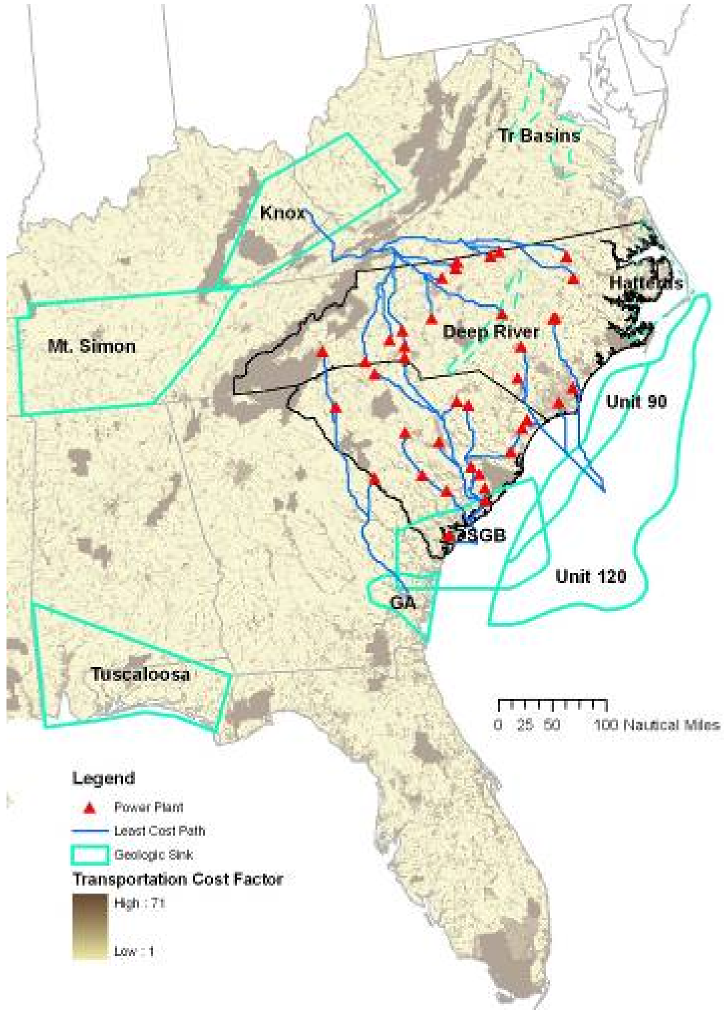


Figure 28. MIT Scenario 3 optimal pipeline network solution.

<u>Source-Sink Matching for Pipeline Scenario 4</u>

In Scenario 4 all the potential sinks except for Hatteras and subseafloor unit 90, and the two South Georgia Basin sinks were used as possible locations for subsurface storage of CO_2 generated by power plants in the Carolinas with a design capacity greater than 100MW. The MIT optimal pipeline network solution for Scenario 4 (fig. 29) utilizes the Knox, subseafloor unit 120, and the Mt. Simon sinks. The objective of this scenario was to force utilization of subseafloor unit 120 by excluding unit 90, and force utilization of Mt. Simon by excluding the SGB sinks. Only two of the power plants in southern SC would utilize the Mt. Simon sink most likely because of the long distance of pipeline required. CO_2 from all of the other power plants that previously utilized the SGB sinks could be transported to the subseafloor unit 120 sink in this scenario. CO_2 generated by most of the power plants in western NC could still be transported to the Knox sink.

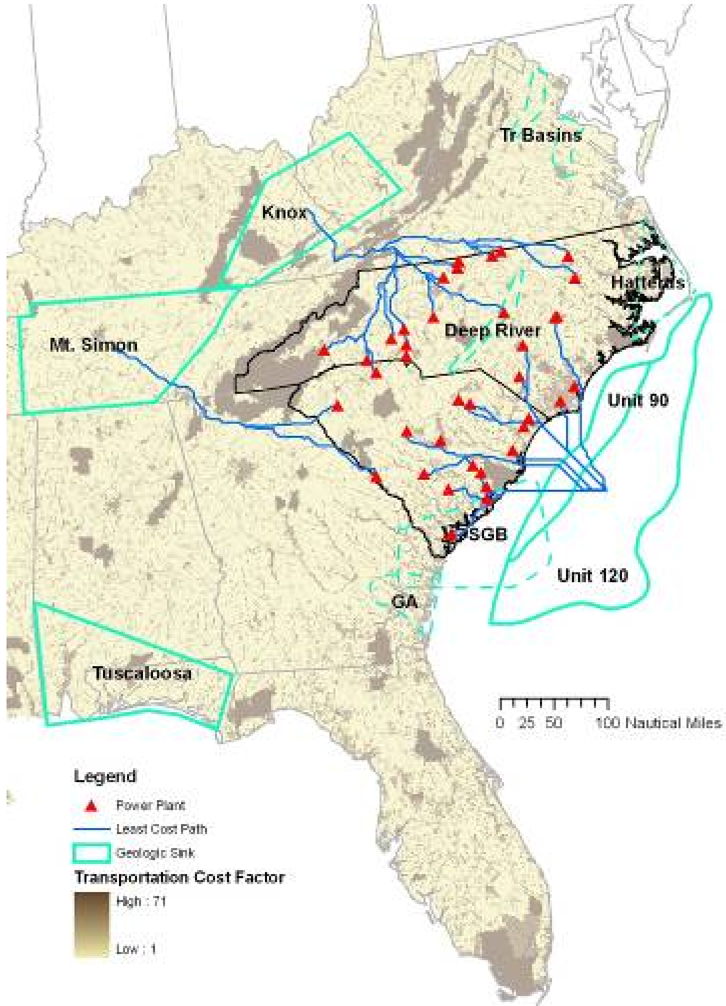


Figure 29. MIT Scenario 4 optimal pipeline network solution.

<u>Source-Sink Matching for Pipeline Scenario 5</u>

In Scenario 5 the Hatteras, subseafloor unit 90, SGB sinks, and Mt. Simon sinks were excluded from consideration. The MIT optimal pipeline network solution for Scenario 5 (fig. 30) utilizes the Knox, subseafloor unit 120, and the Tuscaloosa sinks. The objective of this scenario was to force utilization of subseafloor unit 120 by excluding unit 90 and force utilization of the Tuscaloosa sink by excluding the SGB and Mt. Simon sinks. Only one of the >100MW power plants in southern SC would utilize the Tuscaloosa sink most likely because of the long distance of pipeline required. CO_2 from all of the other power plants that previously utilized the SGB sinks could still be transported to the subseafloor unit 120 sink in this scenario. CO_2 generated by most of the power plants in western NC could still be transported to the Knox sink.

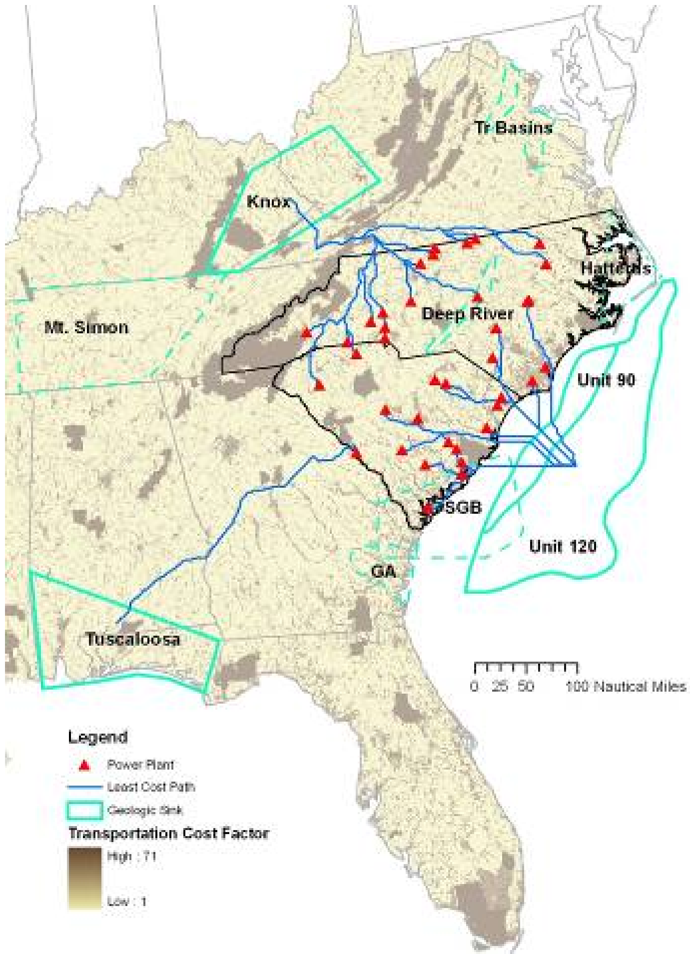


Figure 30. MIT Scenario 5 optimal pipeline network solution.

Conclusions

Most of the power plants in the Carolinas are underlain by geologic units that are not suitable for long-term storage of large volumes of CO_2. The Blue Ridge and Piedmont physiographic provinces of the Appalachian Mountains in western portions of the Carolinas are underlain by crystalline rocks that lack sufficient overlying seals to (1) trap CO_2 in the subsurface or (2) keep it from interacting with fresh groundwater. Sediments of the Atlantic Coastal Plain are not thick enough to host CO_2 sinks and contain deep freshwater aquifers. A potential exception within the Carolinas is an isolated sedimentary basin encompassing the southernmost part of South Carolina that lies within the South Georgia Basin.

Subsurface storage of CO_2 generated in the Carolinas will probably require construction of pipelines to geologic sinks located some distance away from the power plants. The most likely potential geologic sinks for CO_2 generated in the Carolinas are located in (1) the South Georgia Basin (southernmost South Carolina, eastern Georgia, and extending offshore 50 to 75 mi (80 to 120 km), (2) the offshore in strata approximately 0.6 to 1.9 mi (~1 to 3 km) below the Atlantic seafloor, and (3) the Knox Formation in eastern Kentucky and southwestern West Virginia. The CO_2 storage potential for the offshore Atlantic margin is unexplored, but preliminary considerations suggest that CO_2 sequestration options are significant along the entire eastern seaboard. The CO_2 storage potential for the offshore Atlantic margin is unexplored, but preliminary considerations suggest that CO_2 sequestration options are significant along the entire eastern seaboard. Given the limited sink availability in onshore locations of the eastern U.S., and the potentially promising offshore locations, subseafloor injection warrants further evaluated.

Estimates of storage capacity of the potential geologic units identified in this document range from approximately three (Mt. Simon sink in Tennessee) to over 175 gigatons (offshore Atlantic subseafloor sinks). These estimates are based on limited and generalized data sets, which are primarily from published literature. More accurate estimates of capacity for geologic sinks will require site-specific, detailed geologic investigations. Less favorable locations could be considered for storage of small amounts of CO_2, (less than 1 million tons of CO_2 per year) but the economic considerations of subsurface storage requires sinks capable of storing larger volumes. In addition, assessment of the potential geologic sinks is based solely on geologic suitability. Environmental, economic, and socio-political issues will need to be considered before determining which geologic sinks are most suitable for CO_2 storage.

Costs associated with CCS can be separated into two categories—(1) those associated with CO_2 capture and separation and (2) those associated with transportation and storage. Pipeline construction costs are the primary cost factor in the various scenarios, and they vary according to type of terrain that must be traversed. CO_2 transport costs are estimated in terms of \$/ton CO_2, which is the total cost divided by the CO_2 flow rate. Hence, transporting CO_2 at a higher flow rate results in lower transportation costs. Average transportation costs estimated by MIT for the five different scenarios vary from \$3.56 to \$4.21 per metric ton of CO_2 in 2006 equivalent dollars. These costs might be low because (1) MIT based pipeline construction costs on those required to build natural gas pipelines; CO_2 pipelines might be more expensive because of the greater wall thickness needed to contain supercritical (high temperature and high pressure) CO_2, (2) fluctuations in the price of steel, (3) uncertainty in the cost escalation factor for building offshore pipelines.

Acknowledgments

The idea to look for alternative storage locations for CO_2 generated by power plants in the Carolinas came from Dr. Susan Hovorka. Sue's extensive knowledge of geology of the southeastern United States also led to her to the idea of looking for potential geologic sinks in the Atlantic subseafloor offshore from the Carolinas. Thanks to Dr. Julio Friedman for his informal review and encouraging feedback on the idea of storing CO_2 in Atlantic subseafloor sinks. And most importantly, thanks for continued financial support from the four Carolinas power companies and their patience while this report was being finalized.

References

Aucott, W. R., 1988, The predevelopment ground-water flow system and hydrologic characteristics of the Coastal Plain aquifers of south Carolina: U.S. Geological Survey, Water-Resources Investigations Report 86–4347, 66 p.

Bachu, S. Gunter, W. D., and Perkins, E. H., 1994, Aquifer disposal of CO_2 Hydrodynamic and mineral trapping: Energy Conversion and Management, v. 35, no. 4, p. 269–279.

Baranoski, M. T., Riley, R. A., and Wolfe, M. E., 1996, Cambrian-Ordovician Knox Group Unconformity play, *in* Roen, J. B., and Walker, B. J., eds., The atlas of major Appalachian gas plays: West Virginia Geological and Economic Survey Publication v. 25, p. 181–187.

Barker, R. A., and Pernik, M., 1994, Regional hydrology and simulation of deep groundwater flow in the Southeastern Coastal Plain Aquifer system in Mississippi, Alabama, Georgia, and South Carolina: U.S. Geological Survey Professional Paper 1410-C, 87p.

Costain, J. K. and Speer, J. A., 1988, Heat flow and geothermal resource potential of the Atlantic Coastal Plain in: Sheridan, R. E., and Grow, J. A., eds. The Atlantic continental margin: U.S., The Geology of North America, V. I-2, p. 521-528, The Geological Society of America, Boulder, CO.

Davison, I., 2005, Central Atlantic margin basins of North West Africa: Geology and hydrocarbon potential (Morocco to Guinea), Journal of African Earth Sciences, 43 (1-3), 254-274.

Deutch, John, and Moniz, E. J., et al., 2007, The future of coal: options for a carbon-constrained world: Massachusetts Institute of Technology, March 14, Spotlight, http://web.mit.edu/coal/.

Dillon, W. P., Fehlhaber, Kristen, Coleman, D. F., Lee, M. W., and Hutchinson, D. R., 1995, Maps showing gas-hydrate distribution off the east coast of the United States: U. S. Geological Survey Miscellaneous Map Series MF-2268, 2 sheets.

DOE, 2005, Carbon Sequestration, Technology Roadmap and Program Plan: Developing the Technology Base and Infrastructure to Enable Sequestration as a Greenhouse Gas Mitigation Option: U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, 28 p.

Driese, S. G., Byers, C. W., and Dott, R. H., Jr., 1981, Tidal deposition in the basal upper Cambrian Mt. Simon Formation in Wisconsin: Journal of Sedimentary Petrology, v. 51, no. 2, p. 367–381.

Doughty, C. and K. Pruess, 2003, Modeling supercritical CO2 injection in heterogeneous porous media, presented at TOUGH Symposium 2003, Lawrence Berkeley National Lab., Berkeley, Calif., May 12-14, 2003.

Doughty C, K Pruess, SM Benson and BM Freifeld. 2004. "Hydrological and Geochemical Monitoring for a CO_2 Sequestration Pilot in a Brine Formation." *Lawrence Berkeley National Laboratory Report LBNL-55104.* 15 pp.

Fenneman, N. M., and Johnson, D. W., 1946, Physical divisions of the United States: USGS map, scale: 1:7,000,000.

Gohn, G. S., Smith, C. C., Christopher, R. A., and Owens, J. P., 1980, Preliminary cross sections of Cretaceous sediments along Georgia coastal margin: U.S. Geological Survey Miscellaneous Field Studies Map MF -1015-C, 2 sheets.

Gohn, G. S., Christopher, R. A., Smith, C. C., and Owens, J. P., 1978, Preliminary stratigraphic cross sections of Atlantic Coastal Plain sediments of the southeastern United States – Cretaceous sediments along the South Carolina margin: U.S. Geological Survey Misc. Field Studies Map MF -1015-A, 2 sheets.

Harper, J. A. and Patchen, D. G., 1996, Lower Devonian Oriskany Sandstone structural play *in* Roen, J. B., and Walker, B. J., eds., The atlas of major Appalachian gas plays: West Virginia Geological and Economic Survey Publication V-25, pp. 109-117.

Herzog, H. J., 2001, What future for carbon capture and sequestration? Environmental Science and Technology, v. 35, no. 7, p. 148A–153A.

Hoffman, A. J., 2006, Getting Ahead of the Curve: Corporate Strategies that Address Climate Change, *prepared for* the Pew Center for Global Climate Change: http://www.pewclimate.org/docUploads/PEWCorpStrategies.pdf, 138 p.

Holloway, Sam, et al., 1996, The Underground Disposal of Carbon Dioxide: Report for the JOULE II Project CT92-0031.

Horton, J.W., Drake, A.A., and Rankin, D.W., 1989. Tectonostratigraphic terranes and their Paleozoic boundaries in the central and southern Appalachians. Geol. Soc. America Special Paper 230, p. 213-245.

Horton J. W., Jr., and Zullo, v. A., 1991, The geology of the Carolinas; Carolina Geological Society fiftieth anniversary volume, Univ. Tenn. Press, Knoxville, TN, 406 p.

House, K.Z, Schrag. D.P., Harvey, C. F., and Lackner, K.S., 2006, Permanent carbon dioxide in deep-sea sediments: Publication of the National Academy of Science (August 15, 2006), vol. 103, no. 33, pp. 12291-12295.

Hovorka S.D., C. Doughty, S.M. Benson, B.M. Freifeld, S. Sakurai, T.M. Daley, Y.K. Kharaka, M.H. Holtz, R.C. Trautz, H.S. Nance, L.R. Myer and K.G. Knauss. 2006. "Measuring Permanence of CO_2 Storage in Saline Formations: The Frio Experiment." *Environmental Geosciences* 13(2):105-121.

Hovorka S.D., 2006, "Frio Brine Storage Experiment—Lessons Learned." In *8th International Conference on Greenhouse Gas Control Technologies*, 6 pp. Trondheim, Norway.

Hovorka, S. D., Doughty, C., Benson, S. M., Pruess, K., and Knox, P. R., 2004, The impact of geological heterogeneity on CO_2 storage in brine formations; a case study from the Texas Gulf Coast, In: Baines, S. J. and Worden, R. H., eds., Geological storage of carbon dioxide, Geological Society Special Publications, V. 233: 147-163.

Hovorka, S. D., Romero, M. L., Treviño, R. H., Warne, A. G., Ambrose, W. A., Knox, P. R., and Tremblay, T. A., 2000, Project evaluation: phase II: optimal geological environments for carbon dioxide disposal in brine-bearing formations (aquifers) in the United States: The University of Texas at Austin, Bureau of Economic Geology, final report prepared for U.S. Department of Energy, National Energy Technology Laboratory, under contract no. DE-AC26-98FT40417, 222 p.

Hutchinson, D. R., Grow, J. A., Klitgord, K. D., and Swift, B. A., 1982, Deep structure and evolution of the Carolina Trough, In: Watkins, J. S., and Drake, C. L., eds., Studies in continental margin geology, AAPG Memoir 34: 129-152.

Hutchinson, D. R., Poag, C. W., Johnson, A., Popenoe, P., and Wright, C., 1997, Geophysical Database of the East Coast of the United States: Southern Atlantic Margin: Stratigraphy and Velocity in Map Grids: U.S. Geological Survey, Open File Report 96-55, 165 p.

Hutchinson, D. R., Poag, C. W., and Popenoe, P., 1996, Geophysical Database of the East Coast of the United States: Southern Atlantic Margin: Stratigraphy and Velocity from Multichannel Seismic Profiles: U.S. Geological Survey, Open File Report 95-27, 180p.

IEA, 2006, Good news for CO_2 storage under the seabed: IEA Greenhouse Issues, no. 84, December, p. 1.

Jarrell, P. M., Fox, C. E., Stein, M. H., and Well, S. L., 2002, Practical aspects of CO2 flooding: SPE Monograph, v. 22, Richardson, Texas, Society of Petroleum Engineers, p. 220.

King, P. B., 1959, The Evolution of North America: Princeton University Press, 197p., 1 plate.

Klitgord K. D., Hutchinson, D. R., and Schouten, H., 1988, U.S. Atlantic continental margin; structural and tectonic framework, in: Sheridan, R. E., and Grow, J. A., eds. The Atlantic continental margin: U.S., The Geology of North America, V. I-2, 19-55, The Geological Society of America, Boulder, CO.

Klitgord, K. D., and Behrendt, J. C., 1979, Basin structure of the U. S. Atlantic margin, in: Watkins, J. S., and Dickerson, P. W., eds., Geological and geophysical investigations of continental margins, American Association of Petroleum Geologists Memoir 29: 85-112.

Kohout, F. A., Meisler, H., Meyer, F. W., Johnston, R. H., Leve, G. W., and Wait, R. L., 1988, The Atlantic continental margin; U.S., in: Sheridan, R. E., and Grow, J. A., eds., The Geology of North America, V. I-2, 463-480, The Geological Society of America, Boulder, CO.

Lee, M. W., Hutchinson, D. R., Dillon, W. P., Miller, J. J., Agena, W. F., and Swift, B. A., 1993, Method of estimating the amount of in-situ gas hydrates in deep marine sediments, Marine and Petroleum Geology, 10 (5): 493-506.

Mancini, E. A., Mink, R. M., Payton, J. W., and Bearden, B. L., 1987, Environments of deposition and petroleum geology of the Tuscaloosa Group (Upper Cretaceous), South Carlton and Pollard Fields, southwestern Alabama: AAPG Bulletin, v. 71, p. 1128–1142.

Marine, I. W. and Simple, G. E., 1974, Buried Triassic basin in the Central Savannah River Area, South Carolina and Georgia: GSA Bulletin, v. 85, p. 311-320.

McBride, J. H., Nelson, K. D., Brown, L. D., 1989, Evidence and implications of an extensive early Mesozoic rift basin and basalt/diabase sequence beneath the southeast Coastal Plain Geological Society of America Bulletin v. 101, pp. 512-520.

McCoy, Sean, 2006, Pipeline Transport of CO_2—Model Documentation and Illustrative Results: Carnegie Mellon University Manuscript.

Milici, R. C., 1996, Stratigraphic history of the Appalachian Basin, *in* Roen, J. B., and Walker, B. J., eds., The atlas of major Appalachian gas plays: West Virginia Geological and Economic Survey Publication V-25, p. 4–7.

Miller, J. A., 1979, Potential subsurface zones for liquid-waste storage in Florida: Florida Department of Natural Resources, Bureau of Geology, Map Series No. 94.

Miller, J. A., 1990, Ground Water Atlas of the United States—Segment 6, Alabama, Florida, Georgia, and South Carolina: U.S. Geological Survey, Hydrologic Investigations Atlas No. HA-730-G, 28 p.

Montanez, I. P., 1994, Late diagenetic dolomitization of Lower Ordovician, upper Knox carbonates: A record of hydrodynamic evolution of the southern Appalachian basin: AAPG Bulletin, v. 78, pp. 1210-1239.

Nance HS, H Rauch, B Strazisar, G Bromhal, A Wells, R Diehl, R Klusman, J Lewicki, C Oldenburg, Y Kharaka and E Kakouros. 2005. "Surface Environmental Monitoring at the Frio CO_2 Sequestration Test Site, Texas." In *Proceedings, Fourth Annual Conference on Carbon Capture and Sequestration: DOE/NETL, May 2–5*, 16 pp. Alexandria, Virginia. CD-ROM.

Nelson, K.D., J. A. Arnow, J. H. McBride, J. H. Willemin, J. Huang, L. Zheng, J. E. Oliver, L. D. Brown, and S. Kaufman, 1985, New COCORP profiling in the southeastern United States. Part I: Late Paleozoic suture and Mesozoic rift basin: *Geology:* Vol. 13, No. 10, pp. 714–718.

NOAA, 2006, National Geophysical Data Center: www.ngdc.noaa.gov/mgg/topo/globe.html.

Olsen, P. E., Froelich, A. J., Daniels, D. L., Smoot, J. P., and Gore, P. J. W., 1991, Rift basins of early Mesozoic age, *in* Horton, J. W., Jr. and Zullo, V. A., eds., The Geology of the Carolinas: Carolina Geological Society Fiftieth Anniversary Volume: Knoxville, The University of Tennessee Press, p. 142–170.

Read, J. F., 1989, Evolution of Cambro-Ordovician passive margins, United States Appalachians *in* Hatcher, R. D., Jr., Thomas, W. A., and Viele, G. V., eds., The Appalachian-Ouachita Orogen in the United States: Geological Society of America, North American Geology, v. F-4, pp. 44-57.

Renkin, R. A., Mahon, G. L., and Davis, M. E., 1989, Hydrogeology of clastic Tertiary and Cretaceous regional aquifers and confining units in the southeastern coastal plain aquifer system of the United States: U.S. Geological Survey Hydrologic Investigations Atlas HA-701, 3 sheets.

Roen, J. B., and Walker, B. J., eds., The atlas of major Appalachian gas plays: West Virginia Geological and Economic Survey Publication V-25, pp. 109-117.

Rogers, John, 1949, Evolution of thought on structure of middle and southern Appalachians: AAPG Bulletin, v. 33, no. 10 pp. 1643-1654.

Rodgers, John, 1953, Geologic map of east Tennessee with explanatory text: Tennessee Division of Geology Bulletin 58, part II, 168p.

Scholle, P. A., editor, 1979, Geological studies of the COST-GE-1 well, United States South Atlantic Outer Continental Shelf area: U. S. Geological Survey Circular 800, 114 p.

Scripps, 2006, Satellite Geodesy Web page: http://topex.ucsd.edu/WWW_html/srtm30_plus.html.

Shumaker, R. C., 1996, Structural history of the Appalachian Basin, *in* Roen, J. B., and Walker, B. J., eds., The Atlas of Major Appalachian Gas Plays: West Virginia Geological and Economic Survey Publication, v. 25, p. 8–21.

Spencer, E. W., 1972, Structure of the Blue Ridge front in central Virginia *in* Lessing, P., Hayhurst, R. I., Barlow, J. A., and Woodfork, L. D., eds., Appalachian Structures: origin, evolution and possible potential for new exploration frontiers: West Virginia University and West Virginia Geological and Economic Survey, p. 39-48.

Statoil, 2004, Carbon Dioxide: Capture, Storage and Utilization, Research and Technology Memoir No. 5, Oien and Indergaard, Norway.

Temples, T. J., and Waddell, M. G., 1996, Application of petroleum geophysical well logging and sampling techniques for evaluating aquifer characteristics: Ground Water, v. 34, p. 523-531.

Thomas, W. A., 2006, Tectonic inheritance at a continental margin: GSA Today, v. 16, no. 2, pp. 4-11.

Tucker, W. E., and Kidd, R. E., 1973, Deep-well disposal in Alabama: Geological Survey of Alabama Bulletin 104, 229 p.

United States House of Representatives, 1974, Endangerment of drinking water sources: House Report 93-1185, p. 32.

Wilson, J.T., 1966, Did the Atlantic close and then reopen?: Nature, v. 211, p. 676–681.

Ziegler, P. A., 1988, Post-Hercynian plate reorganizations in the Tethys and Arctic-North Atlantic domains in Manspiezer, W. ed., Triassic-Jurassic rifting: Continental breakup and origin of the Atlantic Ocean and passive margins, part B: New York, Elsevier, Developments in Geotectonics 22, pp. 711-755.

<u>CERTIFICATE OF SERVICE</u>

I certify that I have served a copy of the foregoing on all parties of record or to the attorney of record of such party in accordance with Commission Rule R1-39, by United States mail, postage prepaid, first class; by hand delivery; or by means of facsimile or electronic delivery upon agreement of the receiving party.

This the 28th day of May, 2024.

<u>Electronically submitted</u>
/s/Nadia L. Luhr