STATE OF GEORGIA
BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of:

GEORGIA POWER COMPANY'S	)	**DOCKET NO. 56002**
2025 INTEGRATED RESOURCE PLAN	)	

and

GEORGIA POWER COMPANY'S	)	
APPLICATION FOR THE CERTIFICATION,	)	**DOCKET NO. 56003**
DECERTIFICATION, AND AMENDED	)	
DEMAND-SIDE MANAGEMENT PLAN	)	

DIRECT TESTIMONY OF MARIA ROUMPANI, PhD

ON BEHALF OF

GEORGIA CONSERVATION VOTERS.

May 2, 2025

Table of Contents

I. Introduction

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

A. My name is Maria Roumpani. I am a Founding Partner of Current Energy Group LLC. My business address is 2900 E Broadway Blvd, Ste 100 #780, Tucson, AZ 85716.

Q. On whose behalf are you submitting testimony?

A. I am filing testimony on behalf of Georgia Conservation Voters ("GCV").

Q. Have you previously submitted testimony before the Georgia Public Service Commission?

A. No.

Q. Have you ever testified before any other state regulatory body?

A. Yes. I have testified before state utility regulators in Colorado, Michigan, Kentucky, Nevada, North Carolina, Oregon, South Carolina, and Virginia.

Q. Please describe your educational and occupational background.

A. I specialize in the economic and technical analysis of grid planning and operations issues. I have conducted analysis and submitted expert testimony or comments on integrated resource planning, plant economics, unit commitment practices, power cost issues, and demand-side management plans before state utility regulators in Arizona, Colorado, Kentucky, Michigan, Minnesota, Nevada, North Carolina, Oregon, South Carolina, Utah, Virginia, and Washington.

Prior to co-founding Current Energy Group in 2024, I was the Technical Director at Strategen. While at Strategen, I led economic and technical grid modeling engagements, including capacity expansion, production cost, and energy storage dispatch modeling. My clients included government entities and state bodies, including the Oregon Public Utility Commission, the Kentucky Public Service Commission, the Maryland Office of People's Counsel, the South Carolina Office of Regulatory Staff, non-governmental organizations, and trade associations, as well as large energy buyers.

Before joining Strategen in 2018, I contributed to the development of analytical tools used in energy impact assessment studies. I have a Ph.D. from the Management Science and Engineering Department at Stanford University and a Master of Science in Electrical and Computer Engineering from the National Technical University of Athens, Greece. My full resume is attached to this testimony as Exhibit MR-1.

Q. Please describe the purpose of your testimony.

A. The purpose of my direct testimony is to review and evaluate various components of the resource planning analysis and the portfolios presented by Georgia Power Company ("Georgia Power" or the "Company" or "GPC") in its application for approval of its 2025 Integrated Resource Plan ("IRP"). I investigate the Company's load forecasting methodology and resource modeling analysis and assumptions, focusing on whether these position Georgia Power to pursue portfolios that are clean, affordable, and reliable in the long term, while also providing the necessary flexibility (from a planning perspective) given the unprecedented—but uncertain—pace of load growth it is experiencing. I then present analysis for an alternative GCV portfolio of resources that is cleaner, lower cost, and lower risk than the Company's.

Q. How is your testimony organized?

A. Section II presents a summary of my testimony and recommendations. I provide an overview of Georgia Power's IRP analysis in Section III. In Section IV, I outline my concerns about the Company's analysis and how certain elements have contributed to an inflated resource need. In section V, I outline the modeling and results I conducted on behalf of GCV. Finally, in Section VI, I summarize my recommendations and conclude.

II. Findings & Recommendations

Q. Please summarize your findings.

Georgia Power faces a complex resource planning challenge. The uncertainty surrounding its resource need, largely driven by the forecasted large load additions and its ever-increasing Target Reserve Margin ("TRM") is significant and cannot be captured without a robust scenario planning analysis, which the 2025 IRP analysis fails to provide. Both over- and under-forecasting carry risks. For this IRP, after reviewing the Company's load forecasting, resource modeling, and presented plans, I am concerned that Georgia Power is currently planning for an over-forecasted need without sufficiently evaluating the risks.

Furthermore, Georgia Power's analysis relies on resource assumptions and inputs for capital expenses, and technology availability that are out of date, erroneous, and uncertain. The Company's analysis fails to incorporate recent cost increases into the resource costs of new gas-fired units and execution concerns given the current backlog in the combustion turbine market. Consequently, the Company is underestimating the cost and risks of its presented portfolios by several billion dollars.

In correcting some of the resource availability and cost assumptions and reoptimizing using the Company's model and database, I find a better performing portfolio – the GCV Base portfolio – which compared to the Company's proposed 111-MG0 portfolio that meets the Environmental Protection Agency ("EPA") rules under sections 111(b) and

111(d) of the Clean Air Act ("EPA-111") requirements, increases the Company's deployment of clean resources, and reduces its reliance on gas.

The higher investment in renewable energy resources in the GCV Base portfolio reduces ratepayers' exposure to volatile high gas prices and the risk of stranded assets. Specifically, in the event of high gas prices, the difference between the GCV portfolio and the 111-MG0 increases to $9.5 billion. On the other hand, if load growth does not materialize at the magnitude and pace expected, the GCV Base portfolio results in net savings when compared to the Company's portfolios. The higher deployment of clean energy reduces emissions for the GCV portfolios (up to hundreds of millions of tons of carbon) which are not sensitive to the application of the MG0-111 rules (as is the case for the Company's portfolios). In short, renewable energy and energy storage resources are not only economic under the Company's planning assumptions, but deliver value under a broad range of futures, while the value of gas-fired resources (at the Company proposed scale) can quickly diminish if future conditions deviate from the Company's planning assumptions, leaving ratepayers locked to an expensive system and exposed to gas price volatility, policy uncertainty, and changing market conditions.

Importantly, I find that the Company's forecasted large-load growth inflates the projected resource need. I adjust the Company's load forecast and develop another portfolio, the GCV Preferred portfolio which includes (for the Southern Company system):

- 1.5 GW less coal by 2033,
- 6.3 GW less gas-fired resources by 2033 (8.7 GW by 2044),
- 1.2 GW more solar and wind resources by 2033 (7.8 GW by 2044),
- 4 GW more energy storage by 2033 (3.3 GW by 2044), and

- 0.6 GW less nuclear by 2044.

When compared to the 111-MG0 portfolio, the GCV Preferred Portfolio reduces system costs by nearly $10 billion (NPV for the Southern Company system) by 2044.

Q. Please summarize your recommendations.

A. Georgia Power should increase its planning flexibility and ability to adjust to changing conditions by focusing on (a) supply side resources that can provide benefits under a broad range of future conditions (renewable energy and energy storage), and (b) demand side resources that will increase load flexibility. To ensure this is achieved, my recommendations are:

1. The Commission should not approve the 2025 IRP in its current form and require Georgia Power to revise its analysis to:
    a. Present additional resource portfolios developed based on load growth sensitivities. These should at least include:
        i. Adjusted large-load growth scenarios:
            1. Only large load projects that have signed a "Contract for Electric Service" in the near-term, including a probabilistic analysis or possible delays and reductions in announced load.
            2. Large load projects that have signed a "Contract for Electric Service" as above plus an increasing percentage of large loads that are in the "Request for Electric Service" stage subject to a similar probabilistic analysis in the longer term.
        ii. A low economy growth sensitivity combined with the adjusted large-load growth scenarios.

b. Update the resource costs and availability of gas-fired units based on recent market reports and other utilities' filings in the region.

c. Justify the assumed annual build limits and first year of availability for all resource types and explore under what conditions and costs these could be relaxed, especially for renewable energy and energy storage. The analysis should at least investigate whether the following are feasible and under what conditions:

    i. An earlier first year of availability and higher cumulative limit for wind resources.

    ii. An earlier year of availability for medium and long duration energy storage.

    iii. A higher annual build limit for solar resources.

As part of the analysis, the Company should:

- Investigate wind resource availability and barriers to successful procurement of new wind resources (such as transmission investments and procurement design).

- Provide an analysis of the potential of co-locating clean resources to share the same point of interconnection with operating thermal units with low capacity factors, as well as using existing interconnection from retired or soon-to-be retired units to interconnect clean resources.

- Analyze the potential of installing energy storage (including medium and long duration options) at existing/retired plants to take full advantage of investment tax credits (and include such credits in the resource analysis).

d. Include the modeling of seasonal TRM values.

e. Determine and model seasonal Effective Load Carrying Capabilities ("ELCC") values for all resources (including thermal units).

f. Retire Bowen 1&2 prior to 2032. Continue investigating the retirement of all coal units prior to 2032 and postpone actions to co-fire at this time.

2. The Commission should also require Georgia Power to take certain actions going forward as it prepares for future IRPs and Request for Proposals ("RFPs"). In addition to the recommendations in (1):

   a. Increase the accuracy and transparency of its forecasting process to ensure more accurate forecasts are used in the Company's planning analysis in the IRP, as well as in procurements in upcoming RFPs:

      i. Continuously update the probabilities assumed in the Load Realization Model based on the changes reported in its quarterly large load economic development filings.

      ii. Ensure no double counting between the econometric base forecast and the large load adjustment.

   b. Collect and track additional information for the Company's large load pipeline, including the time between one stage to the next, reasons for delays or changes in status, information on the portion of the large loads with clean energy commitments. Include such information in the Company's quarterly Large Load Economic Development reports.

   c. Develop a more robust scenario analysis framework that will evaluate the performance of each portfolio the company presents under a broad range of possible futures, including a broad range of load forecasts.

A. Continue to evaluate coal retirement options for all remaining units prior to 2035.

d. Continue to evaluate opportunities to enhance and expand all customer programs that could further reduce net load and resource needs. Given the projected capacity need, particular focus should be given to improving and increasing customer participation in:

i. Large load customer programs and tariffs like the Large Customer Owned Resiliency Program, the Demand Plus Energy Credit (“DPEC”) interruptible tariff, the Curtailable Load tariff, the consideration of a clean transition tariff,

ii. Other demand response programs, such as the Residential Thermostat Demand Response program.

III. Overview of Georgia Power's Modeling

Q. Please provide an overview of Georgia Power's 2025 IRP.

A. Georgia Power is forecasting unprecedented load growth over the next few years: From 2025 to 2031, winter peaks are projected to grow by approximately 8,200 MW, whereas summer peaks are expected to grow by approximately 8,700 MW during the same period.[1] The 2025 IRP presents the Company's analysis for how to best meet the projected load with the deployment of new resources. Specifically, the Company is proposing to utilize a combination of previously approved Requests for Proposals ("RFPs") and incremental requests of up to 1,500 MW in the near-term. The Company is also proposing new procurements to address capacity and energy needs into the 2030s. The proposed resource buildout in the 2025 IRP outlines a path of continued heavy reliance on fossil fuels for at least twenty more years, deferring the retirement of coal resources, while adding new gas-fired generation every year beyond 2029, totaling more than 17 Gigawatts ("GW") by 2044.[2]

Q. Please provide an overview of Georgia Power's modeling analysis conducted in preparation of the 2025 IRP.

A. To support the IRP requests, the Company utilizes a scenario planning process based on the AURORA capacity expansion model. This process consists of four steps.[3] The Company begins by establishing reliability criteria, forecasting load, assessing existing and planned units, and synthesizing those to determine future system needs. The second

---

[1] Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle, at 16

[2] 2025 IRP Technical Appendix Volume 2, Chapter 2, "Capacity Expansion Plans – 2025 IRP.xlsx," Worksheet MG0 GPC.

[3] 2025 IRP, Figure 3.1

step involves the development of inputs and scenarios which are then used in the third step: the development of generic portfolios. The fourth (final) step includes Georgia Power's interpretation and synthesis of the portfolios, leading to specific resource decisions for the IRP.

Q. What scenarios did Georgia Power consider in its analysis?

A. The four key uncertainties that informed scenario development include environmental regulations, future technology costs and performance, load growth, and fuel prices.[4] Based on different combinations of these four uncertainties, the Company created nine scenarios. Three of these scenarios consider implementation of Environmental Protection Agency's ("EPA") 111 Greenhouse Gas ("GHG") rules, while the other six consider other variations in future conditions in the absence of the 111 GHG rule implementation, as depicted in Figure 3.3 of the IRP, replicated as Figure 1 in this testimony.

Figure 1: 2025 IRP Scenarios

Scenario	GHG pressure view	Tech view	Load view	Fuel view	Label
1	111	Tech Portfolio	Standard	Moderate	111-MG0
2	111	Tech Portfolio	Standard w/ HG0 delta	Higher	111-HG0
3	111 + Higher	IRA 2035	Standard	Moderate	111-MG50
4	Lower	Tech Portfolio	Standard	Lower	LG0
5	Lower	Tech Portfolio	Standard	Moderate	MG0
6	Lower	Tech Portfolio	Standard w/ HG0 delta	Higher	HG0
7	Moderate	IRA 2045	Standard	Moderate	MG20
8	Higher	IRA 2035	Standard	Moderate	MG50
9	Emissions Limit	IRA 2045	Standard	Moderate	EL

Q. Do you have concerns about Georgia Power's analytical approach and the assumptions that informed it?

[4] 2025 IRP at 18.

A. Yes. My concerns span the entire process, from the identification of needs (including the Company's load forecast, and the stated reliability needs), to the technology costs and resource availability assumptions, the scenario and portfolio development, and finally the interpretation and synthesis of those results that informed the Company's action plan. Specifically, my concerns are:

- Georgia Power identifies future resource needs based on two critical analyses: the development of the load forecast, and the determination of the TRM. Each of these contributes to an inflated capacity need, which results in a massive (proposed) resource buildout, exposing Georgia Power consumers to the risk of paying for stranded assets in the future.
- Even if we were to accept that on average, the load forecast is accurate, Georgia Power does not sufficiently explore the uncertainty around it. Georgia Power's development of generic expansion plans is based on a number of scenarios based on four uncertainties. However, the key driver of the projected capacity need, the projected growth of large loads, is not sufficiently explored as a sensitivity. Consequently, Georgia Power does not develop strategies that could mitigate impacts if the actual growth of large loads deviates significantly from the forecasted levels.
- Lastly, even if the projected supply side need was accurate, Georgia Power's analysis includes resource assumptions, including cost and resource availability inputs, that are not consistent with recent trends in the region and across the US. The heavy reliance on new gas-fired resources exposes Georgia Power and its ratepayers to significant execution challenges with likely delays and increased costs for the

construction of the units, as well as fuel price volatility, policy uncertainty, and even reliability issues during their operations.

I explore each of those concerns in greater detail in my testimony.

IV. Georgia Power's Projected Resource Needs

Q. One of your concerns is that Georgia Power's identified resource needs are inflated. Please elaborate.

A. Georgia Power identifies future resource needs based on two critical analyses: the development of the load forecast, and the determination of the reserve margin. As I mentioned before, each of these can contribute to an increasing capacity need. In this section, I review the Company's methodology for forecasting large loads.

Q. What is the Company's load forecast over the next decade?

A. According to the Company's testimony:

> []… Georgia Power's risk-adjusted load forecast from the winter of 2024/2025 through the winter of 2030/2031 now reflects 8,205 MW of load growth, representing an increase of more than 2,200 MW compared to the load growth projections in the 2023 IRP Update for the same period. In the near term, the Company projects nearly 6,000 MW of load growth as early as the winter of 2028/2029. Over the next ten years—through the winter of 2034/2035—Georgia Power expects up to 9,400 MW of load growth.[5]

Based on the Company's current winter peak load of 16,284 MW, this represents an increase of 50% by 2030/2031 and 58% by 2034/2035.[6] The Company attributes the most

[5] Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle, at 13.
[6] 2025 IRP, Attachment 2.0-1: Budget 2025 Forecast Annual Summary.

significant contribution to this load increase from the addition of new "large load" customers.[7]

Q. Are you concerned that the Company's load forecast results in inflated resource needs?

A. Yes. The Company's load forecast keeps growing based on several assumptions as identified by Georgia Power including: continued growth of Georgia's economy, continued growth of the state's population, new demand from commercial and industrial customers such as data centers and manufacturing plants, and finally the electrification of transportation.[8] Although I agree that these factors are likely to contribute to increased electricity demand over the next decade, I am concerned that this might not happen at the scale and pace currently projected by the Company. Even if electricity demand is growing, an exaggerated forecast of that demand can lead to an overbuild of generation assets that will put upward pressure on customer rates at a time when Georgia Power customers are already facing very high costs due to recent generation investments such as Vogtle Units 3 and 4. My review focuses on the Company's forecast of large load customers.

Q. How did the Company adjust its forecast for large load customers?

A. As in the 2023 IRP Update, the 2025 IRP load forecast includes an external adjustment to its baseline forecast to account for the increased large load additions. According to the Company's Budget 2025 Load and Energy Forecast, "an external adjustment is needed

---

[7] 2025 IRP at 35.
[8] Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle, at 12.

for these loads since Georgia's unprecedented economic development growth would not otherwise be captured in the historical trends underlying the baseline forecast."[9] The Company developed a probabilistic model, the Load Realization Model, to address this large load growth.

Q. Do you agree that without the external adjustment, Georgia Power's economic development growth would not be captured?

A. To a certain degree. It is reasonable that large load growth is treated as an external adjustment due to the lack of historical data. However, the Company still performs a base forecast using historical estimates to project commercial and industrial load through econometric models.[10] These econometric models can include some representation of new large load additions. Thus, to the extent that the historical data used to inform the econometric commercial and industrial load projection included large loads, the Company might be double-counting part of that growth.

Q. Has the Company made any adjustments to account for this potential double counting?

A. Not to my knowledge. This contrasts with the approach used by other utilities in recent years. For example, Duke Energy's 2024 Carolina's Resource Plan included a reduction in their load forecast specifically to address this potential double counting issue. [11] Georgia Power did not appear to make any such adjustment.

---

[9] Technical Appendix Volume 1, Budget 2025 Load and Energy Forecast.
[10] Technical Appendix Volume 1, Budget 2025 Load and Energy Forecast, Sections 4 and 5.
[11] "Several of the largest potential projects were used to adjust the forecast this cycle, although the size of the adjustment (in both megawatt-hours ("MWh") and megawatts ("MW") was scaled down from full weight to reflect both the uncertain, future-oriented nature of the plans and the risk of double counting with growth precited by the

Q. Did you review the Company's Load Realization Model?

A. Yes. I reviewed the Load Realization Model as described in the Company's "B2025 Load and Energy Forecast" in Technical Appendix Volume 1. It is a probabilistic model intended to evaluate the range and likelihood of future potential outcomes of the load growth from new large customers. In the model, the uncertainty surrounding each large load addition is quantified through a set of probabilities:

- P1: likelihood that a potential customer will choose to locate in Georgia.
- P2: probability of Georgia Power being chosen as the provider.
- P3: probability of projects reaching commercial operation.
- Probability that the load being served is lower than the customer's initial announcement represented as a range.
- Probability that the commercial operation date of a project is delayed.

The probabilistic model draws, at random, a number for each of the factors above for each project in the model to determine the project success (based on P1, P2, and P3), the fraction of served over announced load, and the delay in commercial operation date. A Monte Carlo simulation is then used to quantify a range of expected load to serve. The 2025 load forecast is the median load level within the range of potential outcomes.

Q. Has the Company provided information about the assumed probabilities used to model the success of a large load project (P1, P2, P3)?

economic factors." Docket No. E-100, Sub 190, North Carolina Utilities Commission, Carolinas Resource Plan, Appendix D: Electric Load Forecast, Available at: https://starw1.ncuc.gov/NCUC/ViewFile.aspx?Id=efa0fef3-0b34-4ee7-bd32-146d7e9e5575

A. Yes. The Company provided the probabilities assigned to the three events determining the success or failure of an individual project.[12] Based on the information provided I calculated each event's expected value for the large loads in the Company's pipeline:

Table 1: Georgia Power's expected value of events for load project success/failure (weighted based on announced load)

P1	P2	P3
87%	61%	95%

Consequently, the Company assumes that:

- 87 per cent of the large load (MW) in the Company's pipeline will choose Georgia as the location.
- 61 per cent of the large load (MW) in the Company's pipeline will choose Georgia Power as the electric service provider for the project.
- 95 per cent of the large load (MW) in the Company's pipeline will reach commercial operation.

Q. Do you believe that these values accurately reflect the probability of success for a large load project?

A. There is no sufficient historical data to properly assess these values. The Company acknowledges that "prior to 2023 IRP Update, the Company had never seen such a significant number of new large customer projects materialize in such a short period of time."[13] Still, the Company claims that P1, P2, and P3 are estimated based on the Company's experience: P1 based on "a **historical** selection rate that is calculated based on the number of projects that chose Georgia versus the number of projects that did not," P2 based on "factors such as competition from other electric service providers, an **existing** relationship with a customer, and the progress of discussions with a customer,"

[12] Georgia Power Response to STF-DEA-3-8 Attachment.
[13] B2025 Load and Energy Forecast" in Technical Appendix Volume 1, at 102.

and P3 based on "the number of projects that **reached** commercial operation versus the total number of projects Georgia Power was **selected** to serve." Furthermore, in its response to STF-DEA-3-10, the Company states that it does not track the reasons why a project is cancelled, making it impossible to accurately estimate the probabilities of the different events leading to a project's success or cancellation.

Q. Do you have reasons to believe that these probabilities result in an overstated load forecast?

A. Yes. There are a number of reasons to believe that the growth of large loads might currently be over-forecasted. Large load customers can be in conversations with several utilities searching for the right option. Every utility will experience project cancellations or withdrawals for different reasons. Large load customers are looking for fast interconnection at low cost, while some of them have clean energy commitments and are interested in increasingly clean portfolios. Georgia Power, which seeks to increase its reliance on fossil fuels and construct an increasing number of gas-fired units during a period that gas turbines are subject to unprecedented delays and cost increases, may lose out to utilities offering cheaper, cleaner energy supply. Furthermore, large load customers, especially data centers, may alter their future energy needs due to a couple of factors. First, big tech companies are still determining how and whether they can turn their AI investment into future profits.[14] If they do not establish a successful business model for this technology, the demand for computing power will decrease. On the other hand, if demand remains high, it is reasonable to expect that AI companies will further

[14] Clare Duffy, CNN, *Has the AI bubble burst? Wall Street wonders if artificial intelligence will ever make money*, August 2, 2024, Available at https://edition.cnn.com/2024/08/02/tech/wall-street-asks-big-tech-will-ai-ever-make-money/index.html.

explore opportunities to make datacenters more efficient to reduce their energy bills, thus reducing their energy demand.[15,16] Secondly, The construction of the facilities will likely be impacted with increasing costs and delays due to widespread tariff increases,[17] while the probability of a recession continues to grow, which could stifle new investments.[18] These increased costs and declining economic situation, combined with the rising costs of electricity might result in growth that is slower than projected a few months ago. Although each of these factors is characterized by uncertainty, they should still be factored in the Company's analysis and inform its resource analysis so that potential impacts to ratepayers are mitigated.

Q. Have you reviewed the Company's current large load economic development pipeline?

A. Yes. Following the 2023 IRP Update, Georgia Power began filing quarterly large load economic development reports, tracking the total number of both committed large load customers and potential large load customers seeking to locate in Georgia. The most recent report, reflecting the update of the last quarter (Q4) of 2024 is summarized in Figure 2.[19] It includes 8.1 GW of customers that are either in the "Contract for Electric Service" or "Request for Electric Service" stage, both of which the Company

---

[15] Kylie Foy, MIT Lincoln Laboratory, *New tools are available to help reduce the energy that AI models devour* October 5, 2023, Available at: https://news.mit.edu/2023/new-tools-available-reduce-energy-that-ai-models-devour-1005

[16] For example, big tech companies invest in improving the energy efficiency of their data centers. See: https://datacenters.google/efficiency/
https://sustainability.atmeta.com/data-centers/
https://datacenters.microsoft.com/sustainability/efficiency/

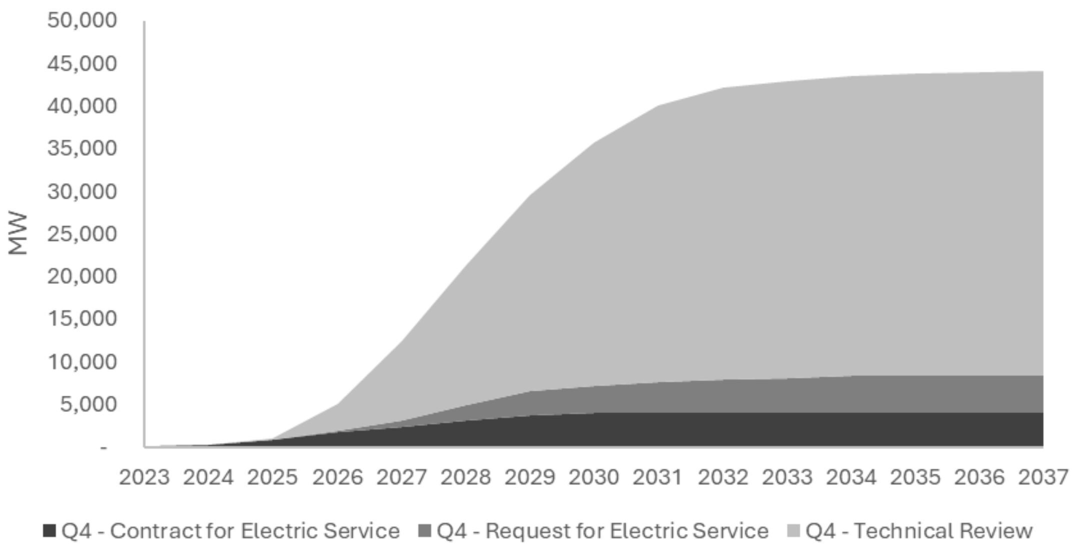
[17] Sharon Goldman, Fortune, *Here's why tariff shock could hit AI's data center boom*, April 7, 2025, https://fortune.com/2025/04/07/ai-risk-exposure-trump-tariffs-chips-datacenter-boom/

[18] J.P.Morgan Research, April 15, 2025, The probability of a recession remains at 60%, https://www.jpmorgan.com/insights/global-research/economy/recession-probability

[19] Georgia Public Service Commission, Docket No. 55378, Large Load Economic Development Report Q4 2024

characterizes as "committed" load.[20] However, it is worth noting that the Company's pipeline, which is used to inform the forecast, is primarily composed of non-committed resources, that are only in technical review, even for near-term load projected developments, including those expected in 2026 and 2027.

Figure 2: Large Load Economic Development Report Q4 2024

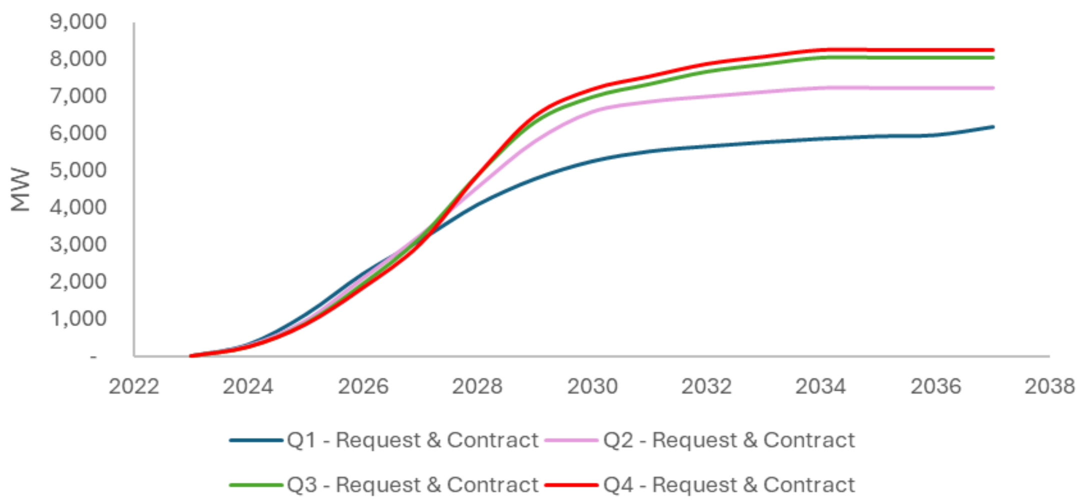


Furthermore, when I compare each of the 2024 quarterly reports,[21] I see significant increases to the non-committed load in the "Technical Review" stages in each quarter, but much smaller changes to the "committed" load (i.e., the Request/Contract for Electric Service stage). In fact, the pace of increases in load that moves from the "Technical Review" stage to the "Request/Contract" stages is slowing down as shown in Figure 3. In addition to that, between the Q1 and Q4 updates, there are delays/reductions (although

[20] Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle, Footnote 3.
[21] Georgia Public Service Commission, Docket No. 55378:
Large Load Economic Development Report Q1 2024
Large Load Economic Development Report Q2 2024
Large Load Economic Development Report Q3 2024
Large Load Economic Development Report Q4 2024

small) in committed load in the near term. Specifically, the committed load for 2026 as reported in Q4 2024 has been reduced by 371 MW from its value in the Q1 2024 report.

Figure 3: Large Load in Request or Contract for Service stages by 2024 Quarterly Report



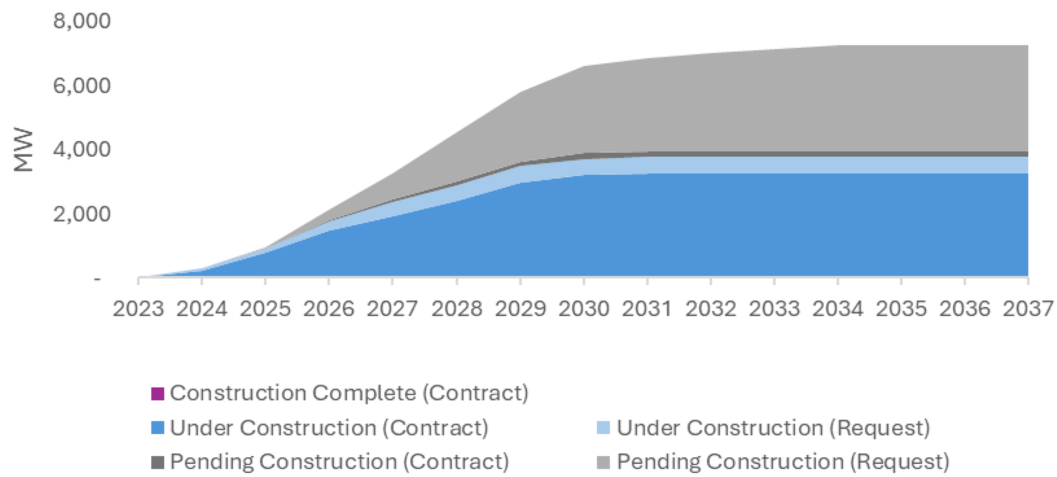
Q. What portion of the "committed" load that is either in the "Request for Electric Service" or "Contract for Electric Service" stage has started construction?

A. Approximately half of the load that the Company characterizes as committed has started construction, as depicted in the figure below. Projects that have yet to begin construction are inherently more likely to be canceled or be delayed. Even projects that have started construction may experience a phased ramp up schedule that differs from initial announcements.[22]

---

[22] Georgia Power accounts for possible delays in the Load Realization Model, assuming a triangular probability distribution with an expected delay of [redacted] months. See, *Budget 2025 Load and Energy Forecast*, Technical Appendix Volume 1, at 106.

Figure 4: Construction status for Committed Load



Q. Could a project that has started construction be cancelled or delayed?

A. Yes. A Microsoft data center in Wisconsin, originally planned for multiple sites and phases, has recently paused construction on expansion sites, and is continuing work only on the first phase.[23] Furthermore, Microsoft seems to be "slowing or pausing" additional data center construction, including a $1 billion project in Ohio.[24]

Q. Have "committed" projects made financial commitments?

A. It is unclear. Georgia Power has provided a template of the "Request for Approval" agreement, but this document does not explicitly reference any financial commitment in the case of cancellation or delay of a project.[25] The template also does not specify the requested load level or its ramp up schedule. Projects that have signed a "Contract for Electric Service" have committed to the terms of electric service, which can include a

[23] Nick Rommel, Wisconsin Public Radio, *Microsoft pauses construction on parts of Mount Pleasant site again,* March 20, 2025. Available at https://www.wpr.org/news/microsoft-pauses-construction-on-parts-of-mount-pleasant-site-again
[24] CBS news, "Microsoft says it's 'slowing or pausing' some AI data center projects, including $1B plan for Ohio," April 12, 2025, https://www.cbsnews.com/pittsburgh/news/microsoft-slowing-or-pausing-ai-data-center-projects-ohio/
[25] Georgia Power response to STF-DEA-5-24 Attachment.

minimum billing demand on the tariff once service starts and up-front fees for connection.[26]

Q. Have other utilities developed methodologies for forecasting large-load growth?

A. Yes. Among electric utilities, the Virginia Electric and Power Company ("Dominion Energy Virginia") possesses significant experience with large loads, especially data centers. In contrast with Georgia Power, the Figure below from Dominion's 2024 IRP shows that the load included in the IRP analysis up to 2031 reflects only a portion of the projects that have already signed an Electric Service Agreement. Dominion notes that:[27]

> Figure 2.1.7 illustrates customer contracts executed as of July 2024. These contracts are broken into (i) Substation Engineering Letters of Authorization ("SELOA"), (ii) Construction Letters of Authorization ("CLOA"), and (iii) Electric Service Agreements ("ESA"). As a customer moves from (i) to (iii), the cost commitment and obligation by the customer increases.

The chart below was excerpted from Dominion's IRP and illustrates how the forecasted load (red line) tracks well below the sum of projects with a signed Electric Service Agreement prior to 2032. The forecast does not include CLOAs up to 2032; it also does not include any of the load under SELOAs at any point, as they are not construction contracts.

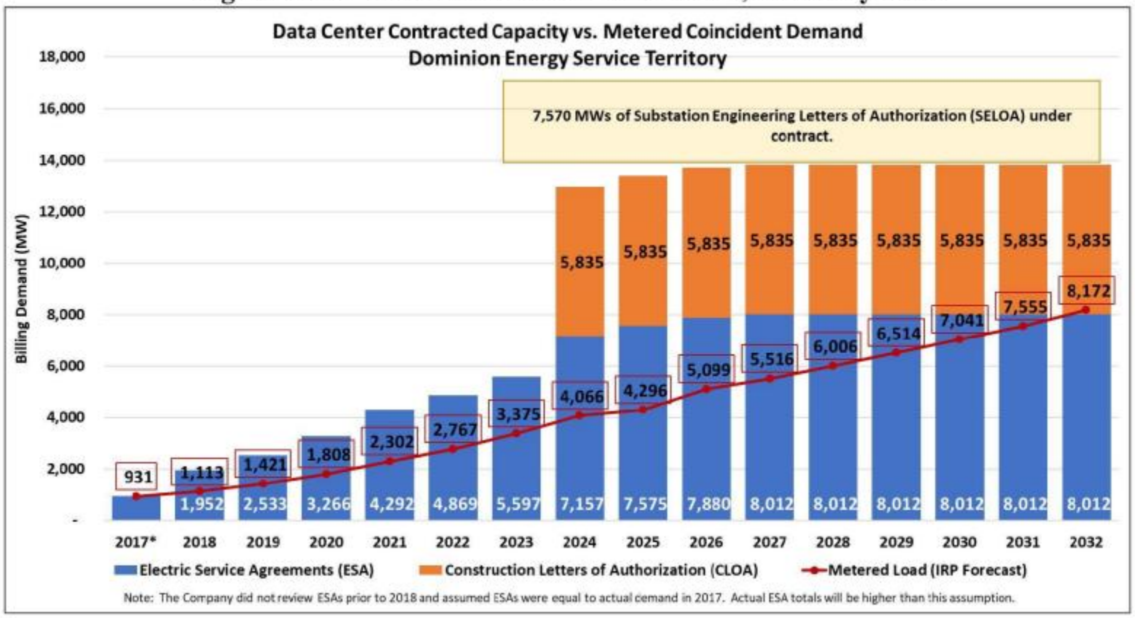
---

[26] Contracts for Electric Service agreements provided by the Company show that [redacted]. See Georgia Power Trade Secret response to STF-PIA-1-10 Attachments M though X.2.

[27] Case No. PUR-2024-00184, Virginia State Corporation Commission, ERRATA FILING November 27, 2024 (2024 Integrated Resource Plan Corrected Page 14 of 81). Available at: https://www.scc.virginia.gov/docketsearch/DOCS/82rt01!.PDF

Figure 5: Dominion Energy Virginia's Data Center IRP Forecast and Contracted Capacity

Figure 2.1.7: Customer Contracts Executed, as of July 2024



Q. What would Georgia Power's large load forecast be if it followed a similar approach?

A. Georgia Power's large load would look significantly different. I re-calculated the large-load growth applying the percentage of contracted load that Dominion includes in its forecast, to Georgia Power's contracted load. I find that in 2031, when Georgia Power is projecting an incremental need of 8.2 GW, the large load growth would be only 4.2 GW.

Figure 6: Adjusted Large Load Forecast Comparison to Company's Base Forecast[28] *(Georgia Power, MW)*

[redacted]

Q. You also mentioned that the Company did not sufficiently explore large-load sensitivities. Please elaborate.

A. The Company developed seven sensitivities for Budget 2025 relative to the "Base Case" forecast.[29] However, it is unclear to me whether and how those load forecast sensitivities were used in the resource portfolio development. The sensitivities include: (1) high economic growth; (2) low economic growth; (3) no load growth; (4) high growth in large load customers; (5) load growth with no Demand Side Management ("DSM") growth; (6) load growth with aggressive DSM growth; and (7) load growth using a 20-year normal definition of weather, as stipulated in the 2019 IRP. Based on my review, resource portfolios were developed with the "Base Case" load forecast as an input, as well as an additional load forecast reflecting small impacts due to high gas price assumption. None of these sensitivities – including the "low economic growth" sensitivity -- reflects a

[28] B2025 Load and Energy Forecast" in Technical Appendix Volume 1, Table 7.2.1 Budget 2025 External Peak Adjustments for Large Loads.
[29] B2025 Load and Energy Forecast" in Technical Appendix Volume 1, at 15.

scenario with a lower large-load forecast. This reflects a critical oversight on the part of Georgia Power. Even if we were to accept the Company's large-load forecast as a good estimate of the expected load – which it is not, Georgia Power should still have explored different probable outcomes. A lower large-load sensitivity is necessary to allow the Commission and intervenors to understand the impact of large load growth on resource buildout, costs, and emissions. A more robust set of scenarios would be needed not only for the purpose of identifying the incremental cost of the large load growth, but more importantly for quantifying the risk of over- and under-forecasting.

Q. How should the Company's use of different load forecasts inform its resource analysis and the Company's near-term actions?

A. All forecasts are characterized by some degree of uncertainty. However, the current period is undeniably one of increased uncertainty for load forecasts, not only with respect to the inclusion of large loads, but also the growth driven by electrification, and overall economic activity. Given that a perfectly accurate forecast is not feasible, the objective of this analysis should be to understand the impacts from potentially over- or under-forecasting and to mitigate ratepayers' exposure to such impacts. Resource planning should be based on a robust scenario analysis aiming to design a portfolio that is not simply optimal under a specific forecast, but that is flexible and resilient, ensuring that resource additions deliver value under a broad range of possible futures. This creates a system that is less sensitive to changes in the forecast and avoids the risk of stranded assets if future conditions do not match current expectations. The Company's scenario analysis fails to assess the flexibility and sensitivity of the resource portfolios to the uncertainty in load forecast. Instead, the Company optimizes its portfolios primarily on just one load forecast, which data shows is likely to over-forecast large loads. An analysis of the Company's resource portfolios through a broad range of future scenarios (including that of lower load growth) is needed to assess the overall risk associated with certain resource actions (instead of simply the portfolios' cost under a specific future). For example, wind energy is shown to be beneficial under all examined futures (both in the Company's and the GCV modeling), while gas-fired resources could be left stranded or with significantly lower value in the case of low load, high gas prices, or certain carbon policy futures.

Q. What is your conclusion with respect to the Company's large-load forecasting methodology?

A. The Company's probabilistic model sets a reasonable framework for the projection of large loads. However, the probabilities assumed need to be continuously assessed and adjusted based on the Company's growing experience, while they should also be informed by broader economic activity data. The Company's assumed probabilities for large load projects to reach completion, on time, and at the initial load level seem over-optimistic and lack support.

Q. What is your recommendation with respect to the Company's load forecast in this IRP?

A. I recommend that the Commission require the following:

1. For this IRP:

   i) Present additional resource portfolios developed based on load growth sensitivities. These should at least include:

(1) Adjusted large-load growth scenarios:

(a) Only large load projects that have signed a "Contract for Electric Service" in the near-term, including a probabilistic analysis or possible delays and reductions in announced load.

(b) Large load projects that have signed a "Contract for Electric Service" as above plus an increasing percentage of large loads that are in the "Request for Electric Service" stage subject to a similar probabilistic analysis in the longer term.

(2) A low economy growth sensitivity combined with the adjusted large-load growth scenarios.

2. On an ongoing basis:

i) Increase the accuracy and transparency of its forecasting process to ensure more accurate forecasts are used in the Company's planning analysis in the IRP, as well as in procurements in upcoming RFPs:

ii) Continuously update the probabilities assumed in the Load Realization Model based on the changes reported in its quarterly large load economic development filings.

iii) Ensure no double counting between the econometric base forecast and the large load adjustment.

iv) Collect and track additional information for the Company's large load pipeline, including the time between one stage to the next, reasons for delays or changes in status, information on the portion of the large loads with clean energy commitments. Include such information in the Company's quarterly Large Load Economic Development reports.

3. Continue to evaluate opportunities to enhance and expand all customer programs that could further reduce net load and resource needs. Given the projected capacity need, particular focus should be given to improving and increasing customer participation in:

   i) Large load customer programs and tariffs like the Large Customer Owned Resiliency Program, the Demand Plus Energy Credit ("DPEC") interruptible tariff, the Curtailable Load tariff, the consideration of a clean transition tariff,

   ii) Other demand response programs, such as the Residential Thermostat Demand Response program.

V. GCV Modeling

Q. Did you conduct modeling to investigate how the portfolio buildout, cost, and emissions would change if the erroneous or highly uncertain inputs you identified were corrected?

A. Yes. I conducted modeling starting from the Company's AURORA model database, as provided by the Company. I performed two types of modeling analysis using the AURORA long term capacity expansion ("LTCE"), as well as standard zonal modules. An LTCE aims to identify the least cost portfolio over a planning period (the Company's AURORA runs have a planning horizon up to 2059). A zonal analysis, which I also refer to as a production cost run, simulates the operations of the portfolio over the planning period (assuming least cost dispatch). The AURORA model utilizes system and scenario specific inputs including load forecasts, existing and new candidate resource characteristics, and reserve margin requirements. In this section, I describe GCV's changes to the model and results, focusing on resource availability and costs.

Q. Did you use one of the Georgia Power scenarios outlined in Figure 1 as the starting point of your modeling analysis?

A. Yes. I based my model setup on the Company's MG0, MG20, and 111-MG0 scenarios. MG0 simulates a scenario that includes no carbon policy and develops a least cost portfolio focusing only on the direct costs of the different resources. The base GCV portfolio is developed incorporating the carbon price of MG20. The inclusion of a carbon price recognizes first and foremost that carbon emissions impose real costs on the people of Georgia and everywhere, as well as the reality that environmental policy in some form will be part of the grid's future. I also conducted modeling including the Environmental Protection Agency ("EPA") rules under sections 111(b) and 111(d) of the Clean Air Act ("111 GHG Rules"), as the Company presents the 111-MG0 scenario as its base case.[30]

A. Input Changes

Q. Please list the input changes that you incorporated in the model runs you conducted.

A. In my model runs, I adjusted a limited number of inputs. These include:

1. The capital costs of gas-fired resources;
2. The annual build limits of different technologies;
3. The effective load carrying capability ("ELCC") value for solar resources.

In addition to that, I allowed the model to select partial additions of energy storage and renewable energy resources, as these resources are highly modular. I also adjusted some

[30] Direct Testimony of Jeffrey R. Grubb, J. Randy Hubbert, M. Brandon Looney, Michael B. Robinson, and Francisco Valle, at 28.

of the time resolution settings of the LTCE, but simulated the operations of all portfolios through detailed production cost simulations to ensure a consistent comparison.

Q. Please explain why you updated the capital costs assumed for new gas-fired resources.

A. Georgia Power's capital cost assumptions are summarized in Table 5: B2025 Technology Cost and Performance Summary of the 2025 IRP Resource Mix Study. I compared these costs with other sources that include the National Renewable Energy Laboratory's ("NREL") 2024 Annual Technology Baseline ("ATB")[31], as well as resource costs in recent applications for IRPs and Certificates of Public Convenience and Necessity ("CPCN"). Data from IRPs is summarized in Table 2:[32]

Table 2: Comparison of Resource Costs in recent IRPs[33]

Technology	GPC IRP	NREL ATB	DESC IRP	LGE/KU IRP	PacifiCorp IRP
Natural Gas Combined Cycle (NGCC)	[redacted]	$ 1,865	$ 2,453	$ 1,850	$ 1,839
NGCC with Local CCS	[redacted]	$ 3,558			$ 3,429
NGCC with Distant CCS	[redacted]				
Combustion Turbine with SCR, Oil Winter (CT w SCR)	[redacted]	$ 1,425	$ 1,494	$ 1,427	$ 1,387
Solar Photovoltaic (PV) - Single Axis Tracker (SAT)	[redacted]	$ 1,663	$ 1,630	$ 1,659	$ 1,217
Onshore Wind Power	[redacted]	$ 1,891	$ -	$ 1,953	$ 1,492
Lithium-ion Battery Energy Storage System (BESS) - 4 Hr	[redacted]	$ 2,078	$ 2,036	$ 1,788	$ 1,623
Medium Duration Energy Storage System	[redacted]	$ 4,450	$ 4,079	$ 3,139	$ 2,730
Nuclear	[redacted]	$ 10,345	$ 12,581	$ 8,520	$ 9,662

---

[31] Available at https://atb.nrel.gov/electricity/2024/technologies.

[32] All costs are expressed in 2024$, although it is difficult to ensure consistency in installation dates. For example, nuclear resources in most sources cited refer to Small Modular Reactors with an assumed availability post 2030. LG&E/KU values were deflated from 2030$, but it is not clear whether those estimates refer to a 2030 installation. Medium Duration Storage Options reflect different duration assumptions in each source ranging from 8 hours to 100 hours).

[33] See the following IRP sources:

1. Georgia Power, 2025 IRP Technical Appendix Volume 2, *Technology Screening and Application Standards*, Attachment B
2. Dominion Energy, *DESC IRP Stakeholder Advisory Group Session XVI*, Supply-Side Inputs Candidate Resource Options, available at https://www.desc-irp-stakeholder-

Additional data, mainly for gas-fired resources, can also be found in recent CPCN applications. Although I recognize that each CPCN application includes cost estimates that can be location- and case- specific, a trend of higher costs for gas-fired units is evident. Some examples include:

- Kentucky Utilities Company ("KU") and Louisville Gas and Electric Company ("LG&E") applied to the Kentucky Public Service Commission for CPCNs for the construction of two approximately 645 MW gas advanced class 1x1 single-shaft Combined Cycle ("CC") facilities, one at KU's E.W. Brown Generating Station in Mercer County, Kentucky and the other at LG&E's Mill Creek Generating Station in Jefferson County, Kentucky, as well as for the construction of a 400 MW, 4- lithium-ion battery energy storage system facility. LG&E/KU estimate the construction cost of Brown 12 and Mill Creek 6 to be $1.383 billion and $1.415 billion, respectively, while the cost of the BESS facility is expected to be $775.[34] Expressed in $/kW, these costs are $2,144/kW and $2,193/kW for the CC units and $1,937/ for the storage facility.

- Duke Indiana applied to the Indiana Utility Regulatory Commission for a CPCN for two 1x1 Advanced Class CC gas units at the Company's existing Cayuga Generation Station. Each unit will have a winter rating of approximately 738 MW, for a

---

group.com/Portals/0/Documents/MeetingMaterials/DESC_IRP_Stakeholder_Advisory_Group_Session_XVI.pdf

3. Louisville Gas and Electric and Kentucky Utilities, *2024 Joint Integrated Resource Plan Volume III*, Technology Update, tables 1, 2, and 3.
4. PacifiCorp IRP support and studies, *Public Supply-Side Resource Data Summary – 2025*. Available at https://www.pacificorp.com/energy/integrated-resource-plan/support.html

[34] Case No. 2025-00045, Kentucky Public Service Commission, *Direct Testimony of David L. (Dave) Tummonds Senior Director*, at 10 and 13. Available at https://psc.ky.gov/pscecf/2025-00045/rick.lovekamp%40lge-ku.com/02282025010202/16-Tummonds_Direct_Testimony_2025-00045.pdf

combined winter capacity rating of 1,476 MW.[35] Project construction is expected to occur from 2025 until 2030 with nearly $2.97 billion in expenditures on equipment, construction employee compensation, professional services and materials, plus additional costs such as financing and transmission line upgrades necessary to transport the additional power, bringing total estimated project cost to $3.3 billion.[36] Expressed in $/kW, these values are $2,012 - $2,234/kW.

- Dominion Energy Virginia applied for a CPCN to construct and operate the Chesterfield Energy Reliability Center. The project will be located in the footprint of Dominion's existing Chesterfield Power Station site in Chesterfield, Virginia and consist of four 236 MW Combustion Turbines ("CTs"), for a total of 944 MW. The total estimated cost is approximately $1.47 billion, and the Project is expected to begin commercial operations by June 1, 2029.[37] Expressed in $/kW, this equals $1,557/kW.

Q. Why are costs for gas-fired resources significantly higher than cost estimates encountered in IRPs of earlier years?

A. The gas turbine market is experiencing a significant backlog due to the increased demand resulting in both higher costs, as well as longer timelines for the delivery of turbines. This has been reported in several articles. A recent newsletter summarizes information about

---

[35] Cause No. 46193, Indiana Utility Regulatory Commission, *Direct Testimony of Stan C. Pinegar*, at 12, Available at: https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/026a0346-edea-ef11-be20-001dd80b89f5/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=46193_Duke%20Energy%20Indiana_Direct%20Testimony%20of%20Pinegar_021325.pdf

[36] Cause No. 46193, Indiana Utility Regulatory Commission, Attachment 1-A (SCP), at 5. Available at: https://iurc.portal.in.gov/_entity/sharepointdocumentlocation/026a0346-edea-ef11-be20-001dd80b89f5/bb9c6bba-fd52-45ad-8e64-a444aef13c39?file=46193_Duke%20Energy%20Indiana_Direct%20Testimony%20of%20Pinegar_021325.pdf

[37] Case No. PUR-2025-00037, State Corporation Commission of Virginia, *Direct Testimony of Jeffrey G. Miscikowksi, at 3-4.* Available at: https://www.scc.virginia.gov/docketsearch/DOCS/845p01!.PDF

this growing backlog of gas turbine orders from the major manufacturers:[38] "The global gas turbine market is experiencing a significant surge in orders, with major players like Siemens Energy, GE Vernova, and Mitsubishi Power reporting record-breaking backlogs in 2024."

Q. What are the potential impacts of this backlog?

A. The newsletter identifies some critical impacts for potential customers and eventually electricity consumers. According to that newsletter, those include:

1. Delays in Project Execution: Long backlogs can disrupt construction schedules and lead to cost overruns. Some gas turbine models now have leading times of up to 37 months, substantially affecting project planning and execution.
2. Strain on Maintenance and Spare Parts Availability: Current gas turbine operators are increasingly concerned about slower turnaround times for scheduled maintenance. Customers are now experiencing lead overhaul times of around 350 days, a sharp increase from the 120 days that were previously standard.
3. Rising Costs for End-Users: The high backlog demand has shifted pricing power to OEMs, meaning customers may pay more for both new turbines and service agreements. Additionally, inflationary pressures on raw materials and supply chain constraints are further driving up capital and operational costs for gas turbine buyers.
4. Uncertainty in Decarbonization Strategies: Many power producers are investing in hydrogen-compatible gas turbines as part of their long-term net-zero strategies. However, backlog-induced delays may slow the transition to cleaner gas power.

Q. Please explain how you updated the capital costs assumed for new gas-fired resources.

A. Based on the comparison table provided above, I increased the build costs for CC resources by a conservative [redacted] in 2030,[39] an increase that I gradually reduced within a five year period, assuming the backlog will gradually resolve either due to adjustments in

[38] *The Growing Backlog of Gas Turbine Orders: Implications for Customers*, 01/03/2025, Available at: https://gasturbinehub.com/the-growing-backlog-of-gas-turbine-orders-implications-for-customers/

[39] The Company's database included [redacted] build costs **(i.e., $[redacted] kW)** for **new** CC resources in 2029. Assuming that this is simply an error, I included costs in 2029 consistent with my 2030 assumption.

demand or in the supply capabilities of the manufacturers. Similarly, I assumed a [redacted]% increase for CTs in 2030, with costs returning to Georgia Power's assumed levels within a five-year period. For both CC and CT resources I adjusted the recovery of build costs in the revenue requirement to 35 years.

Q. Did you adjust the costs of other resources?

A. No. I compared the costs of solar, wind, and energy storage resources mainly with other IRPs, including those of LG&E/KU, Dominion Energy South Carolina, PacifiCorp, as well as the NREL ATB. Although differences exist for both renewable energy and four-hour batteries among those sources, I found that Georgia Power's assumptions do not differ so much as to require an adjustment, especially taking into consideration the conservative increases applied to the gas-fired resources. Furthermore, had the Company assumed hybrid resources (renewable energy paired with energy storage), additional cost savings would almost eliminate the delta shown in this table. Specifically, NREL ATB assumes that paired resources would result in 8% savings (compared to standalone renewable energy and energy storage assets) based on the synergistic effects that reduce the capital cost (reduced development, financing and other costs).[40] I also did not include any changes to the Company's CC with Carbon Capture and Sequestration, nuclear, or medium duration energy storage assumptions.

Q. Please explain the role of build limits in a capacity expansion model.

A. The capacity expansion model, which seeks to develop the least-cost portfolio under an assumed future, is subject to certain constraints, one of which is how much of a resource

[40] 2024 ATB Data, tab "Utility-Scale PV-Plus-Battery," cell S40, Available at: https://data.openei.org/files/6006/2024_v3_Workbook.xlsx

can be deployed on an annual basis (annual build limit), or over the course of several years (cumulative build limit).

Q. Has Georgia Power assumed build limits in its AURORA runs?

A. Yes. Table 3 summarizes those limits:[41]

Table 3: Georgia Power's assumed build limits

Technology	First Year	Modeling Limitations
NGCC	2029	• 2029: limited to 900 MW • 2030: limited to 4500 MW • 2031 and after: limited to 9000 MW • Natural gas firm transportation ("FT") availability
NGCC with CCS (local sequestration)	2037	• Limits based on FT availability & Geology
NGCC with CCS (distant sequestration)	2037	• FT availability
CT with SCR	2029	• No limit
Solar PV	2028	• 1,500 MW/year
Wind	2033	• 300 MW/year, 4,500 MW total
BESS	2028	• 3,000 MW/year
MDESS	2033	• 3,000 MW/year
Nuclear (AP-1000)	2037	• 600 MW/year

Q. Do you have concerns about Georgia Power's assumed renewable energy build limits?

A. Yes. First, I recognize that Georgia Power will have to address execution issues as they will be procuring and interconnecting significant amounts of different resource types. Including procurement and interconnection limitations through some kind of model constraint is not unreasonable. However, when those resource limits are binding every year, they should be critically reviewed and thoroughly justified. For example, solar and wind resources are subject to annual limits which are binding in all years for several of

[41] Georgia Power response to STF-JKA-1-11

the presented scenarios (see Table 4 and 5).[42] This indicates that the development of a least cost portfolio is limited by those constraints, which if relaxed could further reduce costs for ratepayers. Thus, it would be informative for Georgia Power to explore under what conditions and costs these constraints could be relaxed, especially for renewable energy and energy storage.

Table 4: Solar build limits and optimal levels in Georgia Power's portfolios

	Solar Model Limit	Solar MW - Model Selection								
		MG0	LG0	HG0	MG20	MG50	EL2	111-MG0	111-HG0	111-MG50
2025	[redacted]	0	0	0	0	0	0	0	0	0
2026	[redacted]	0	0	0	0	0	0	0	0	0
2027	[redacted]	0	0	0	0	0	0	0	0	0
2028	[redacted]	0	0	1500	1500	1500	1500	1500	1500	1500
2029	[redacted]	0	0	1500	1500	1500	1500	1500	1200	1500
2030	[redacted]	0	0	0	0	0	0	0	0	0
2031	[redacted]	0	0	900	900	900	900	900	900	900
2032	[redacted]	0	0	1500	1500	1500	1500	1500	1500	1500
2033	[redacted]	1500	0	1500	1500	1500	1500	1500	1500	1500
2034	[redacted]	1500	300	1500	1500	1500	1500	1500	1500	1500
2035	[redacted]	1500	1500	1500	1500	1500	1500	1500	1500	1500
2036	[redacted]	1500	1500	1500	1500	1500	1500	1500	1500	1500
2037	[redacted]	1500	1500	1500	1500	1500	1500	1500	1500	1500
2038	[redacted]	1500	1500	1500	1500	1500	1500	1500	1500	1500
2039	[redacted]	1500	1500	1500	1500	1500	1500	1500	1500	1500
2040	[redacted]	1500	1500	1500	1500	1500	1500	1500	1500	1500
2041	[redacted]	1500	1500	1500	1500	1500	1500	1500	1500	1500
2042	[redacted]	1500	1500	1500	1500	1500	1500	1500	1500	1500
2043	[redacted]	1500	1500	1500	1500	1500	1500	1500	1500	1500
2044	[redacted]	1500	1500	1500	1500	1500	1500	1500	1500	1500

[42] Based on Georgia Power response to STF-JKA-1-11 and 2025 IRP Technical Appendix Volume 2, Chapter 2, "Capacity Expansion Plans – 2025 IRP.xlsx."

Table 5: Wind build limits and optimal levels in Georgia Power's portfolios

	Wind Model Limit	Wind MW - Model Selection								
		MG0	LG0	HG0	MG20	MG50	EL2	111-MG0	111-HG0	111-MG50
2025	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0
2031	0	0	0	0	0	0	0	0	0	0
2032	0	0	0	0	0	0	0	0	0	0
2033	300	300	300	300	300	300	300	300	300	300
2034	300	300	300	300	300	300	300	300	300	300
2035	300	300	300	300	300	300	300	300	300	300
2036	300	300	300	300	300	300	300	300	300	300
2037	300	300	300	300	300	300	300	300	300	300
2038	300	300	300	300	300	300	300	300	300	300
2039	300	300	300	300	300	300	300	300	300	300
2040	300	300	300	300	300	300	300	300	300	300
2041	300	300	300	300	300	300	300	300	300	300
2042	300	300	300	300	300	300	300	300	300	300
2043	300	300	300	300	300	300	300	300	300	300
2044	300	300	300	300	300	300	300	300	300	300

Q. What are the implications of the fact that the amount of wind and solar selected equals the assumed build limits in nearly every year?

A. To put it plainly, the optimal, least-cost portfolio is one that "maxes out" wind and solar additions. A lower cost portfolio could be determined if the Company were able to achieve wind and solar additions greater than the assumed build limits. Significant wind and solar additions can be considered "no regrets" options.

Q. Has the Company updated its build limits for renewable energy since the last IRP?

A. Yes. According to the Company's response to STF-JKA-1-11, the annual and cumulative limits for wind resources were reduced from 600 MW/yr and a cumulative max of 8,100 MW to 300 MW/yr and a cumulative max of 4,500 MW.

Q. Has the Company provided a reasonable explanation for the selection of the specific levels for the annual limits for solar and wind additions?

A. Not to my knowledge. The Company's response to STF-JKA-1-11 provides some information on the assumed limits for new gas resources, but not for renewable energy, or for why those were updated since its 2023 IRP Update.

Q. How could Georgia Power increase the amount of renewable energy and energy storage that it can interconnect on an annual basis?

A. Besides larger transmission projects, which I have not analyzed in this review, Georgia Power could increase the clean energy resources that it interconnects every year by leveraging its existing infrastructure. For example, Georgia Power should conduct an analysis of the potential of co-locating clean resources to share the same point of interconnection with operating thermal units with low capacity factors, as well as using existing interconnection from retired or soon-to-be retired units. Similarly energy storage could be interconnected at the point of interconnection of existing solar resources to increase the firm capacity of the combined resource while resulting in cost and time savings. The analysis should further evaluate the potential of installing clean resources (including medium and long duration options) in energy communities to take full advantage of investment tax credits (and include such credits in the resource analysis).[43]

[43] As defined in the Inflation Reduction Act (IRA), the Energy Community Tax Credit Bonus applies a bonus of up to 10% (for production tax credits) or 10 percentage points (for investment tax credits) for projects, facilities, and technologies located in energy communities. The definition of energy communities includes (among others) brownfield sites and a census tract (or directly adjoining census tract) in which a coal-fired electric generating unit has been retired after 2009. A mapping tool developed by the Department of Energy shows that clean resources located in certain parts of Georgia would be eligible for the credit. https://arcgis.netl.doe.gov/portal/apps/experiencebuilder/experience/?id=a2ce47d4721a477a8701bd0e08495e1d

Q. Do you have concerns about Georgia Power's assumed annual build limits for gas-fired resources?

A. I am concerned that the limits for CC and CT resources are unrealistically high. Other than 2029 CC resources, CCs and CTs are essentially not constrained. This results in the Company's MG0 scenario selecting more than 3,300 MW of new gas-fired resources in a single year (2031, for the Southern Company system), and more than 8 GW in the four-year period 2029-2032.[44] Constructing 8 GW of new gas-fired resources in this four-year period raises several execution concerns. In the GCV modeling presented below, CC resources were subject to a limit of 900 MW in 2029 (consistent with Georgia Power's assumption) and 1,200 MW on an annual basis up to 2038.

Q. Do you have any concerns about the Company's assumptions for the first year of availability for different resource types?

A. Yes. The first year of availability for incremental CC and CT resources is 2029, which based on the backlog described previously might not be realistic. Despite my concerns for whether Georgia Power could successfully bring new gas-fired resources online by 2029, I did not adjust this input. On the other hand, Georgia Power assumes that wind energy and medium duration energy storage will be available in 2033. In my modeling, I assumed that both resources could start operating in 2030.

Q. Did you adjust the ELCC values for solar resources?

A. Yes. The Company's model assigned zero capacity value to all solar. I adjusted the ELCC values for solar resources to reflect values based on the results of the Company's

[44] 2025 IRP Technical Appendix Volume 2, Chapter 2, "Capacity Expansion Plans – 2025 IRP.xlsx,"

ELCC study which finds a small but non-zero capacity value for solar even in the winter planning period.[45] While I did not model the ELCC of solar seasonally, the Company's ELCC study does find greater capacity value of solar in the summer period. This is also true for the capacity value of energy storage. In general, the inputs to the model should reflect seasonal variations for values like capacity value, and TRM, since the Company has emphasized its seasonal planning strategy.

B. GCV Base Portfolio

Q. Please describe the GCV base model results.

A. With the changes described above, I performed an LTCE to derive a base portfolio. The optimal resource additions of this portfolio are presented in the table below, in comparison with the Company's MG0, MG20, and 111-MG0 resource additions. The amount of nameplate capacity additions of each technology is given for two timeframes: the period of 2025-2033, representing the immediate future need for which the Company is proposing actions in this IRP, and 2025-2044, aligned with the IRP's 20-year planning horizon. My focus is primarily on actions in the near term, as longer-term additions will continue to be evaluated in future IRPs.

[45] Georgia Power response to STF-JKA-1-10 Attachment D.

Table 6: Comparison of Resource Additions (for Southern Company, in MW Nameplate) for GCV's Base and Company Portfolios[46]

Period	Portfolio	CT	CC & CC w/ CCS	Solar	Wind	4-hr Storage	12-hr Storage	Nuclear
2025-2033	GCV Base	1,200	4,200	10,200	1,200	5,100	1,857	0
	GPC MG0	3,300	5,400	1,500	300	3,900	0	0
	GPC MG20	2,400	6,300	6,900	300	4,500	0	0
	GPC 111-MG0	3,600	5,100	6,900	300	2,700	0	0
2025-2044	GCV Base	6,000	10,800	33,300	4,500	11,970	1,902	0
	GPC MG0	9,900	11,400	18,000	3,600	5,100	900	0
	GPC MG20	8,400	12,600	23,400	3,600	8,100	600	300
	GPC 111-MG0	8,400	13,500	23,400	3,600	6,600	0	600

The comparison of GCV's base case to the Company's MG0 and MG20 portfolios shows an increase in renewable resource additions, to the maximum annual build limits. GCV's base portfolio includes more solar than any of the Company portfolios, as I have assumed higher availability, and the model has consistently selected it. Similarly, wind resources are selected to the maximum amount every year. In addition, the model increases the amount of 4-hour battery and medium-duration 12-hour storage in the GCV portfolio, replacing some of the gas-fired resources of the Company's portfolios.

Q. Did you also conduct a production cost analysis for the GCV base portfolio?

A. Yes. I performed a production cost analysis with Aurora's standard zonal study option. This analysis takes the buildout of the LTCE run as an input and simulates the operations of the portfolio over the planning period.

Q. What was the purpose of conducting production cost analysis?

[46] 2025 IRP Technical Appendix Volume 2, Chapter 2, "Capacity Expansion Plans – 2025 IRP.xlsx."

A. A production cost analysis can provide more accurate information about the operations of the units, the expected portfolio costs, and emissions using higher resolution and accuracy in the dispatch and commitment logic. For example, I conducted production cost analysis simulating every hour of every day of every year, instead of the representative time blocks used in the long-term studies. Furthermore, the production cost analysis allows a given resource portfolio to be analyzed with a different set of conditions (for example, with EPA 111 operating compliance constraints, or modified load and fuel price) than it was developed for in the LTCE. An LTCE determines a least cost portfolio under a deterministic future, which might not be optimal under another future and does not consider uncertainty. Simulating the operations of the developed portfolio under a different set of future assumptions can provide insights as to how sensitive it is to changing conditions (i.e. how its performance, including costs and emissions change if some inputs take different values). The optimization process of the LTCE is also sensitive to model settings or even the setup of the machine used to conduct the modeling. Production cost runs allow for a consistent comparison of different portfolios under different scenarios, independently of how those portfolios were constructed. For the results below, whenever a portfolio is run under a different future scenario than it was developed within, to test its performance under different conditions, I include (zonal) in its description.

Q. How does the GCV Base portfolio compare to the Company's portfolios in terms of costs?

A. To compare the costs associated with investing and operating the GCV portfolio, as well as any of the Company's portfolios, I conducted a series of production cost runs. Each of the portfolios is run under the same assumptions (including the updated costs of the gas-fired units). The system costs of each resource portfolio for the 20-year horizon is provided, in terms of net present value ("NPV"), in the table below. The system cost is composed of fixed costs and production costs. Fixed costs include the capital expenses to build the portfolio, as well as fixed operations and maintenance costs of the units. Production costs include the costs for fuel, maintenance, and other operating expenses that are determined by how the portfolio is run to meet the system demand. Each of the production cost runs also calculates the carbon emissions of each portfolio in the 20-year period, as well as their carbon cost under the carbon price of the Company's MG20 portfolio.[47]

Table 7: Comparison of system cost for GVC Base and Company Portfolio for 2025-2044 (for Southern Company, NPV)

	Fixed Cost ($B)	Production Cost ($B)	Total System Cost ($B)	Carbon Cost ($B)	System + Carbon Cost ($B)
GCV Base	[redacted]				
GPC MG20					
GPC MG0					

The results of the production cost analysis show that the GCV Base portfolio results in a lower system cost than the Company's MG20 and reduces the combined system and carbon costs by more than $2.5 Billion (i.e., System + Carbon Cost). Although the MG0 scenario (no carbon policy or price) is not reflective of reality, as it ignores carbon costs and assumes that there will be no carbon policy in any form up to 2044, I compare it to the GCV Base to showcase that investing in cleaner portfolios does not lead to increased

[47] The carbon cost was not included in dispatch decisions.

costs. The system costs of the two portfolios are comparable, but the MG0 portfolio results in significantly increased carbon emissions.

To understand how the GCV Base would perform if the EPA 111 rules stay in place, I simulated its operations through a production cost run with the same constraints as the Company's EPA 111 evaluation and compared it to the Company's 111-MG0 portfolio. Under this scenario, the system and carbon cost reductions under the GCV portfolio increase to over $3 billion.

Table 8: Comparison of System Cost for GCV and Company Portfolio assuming EPA 111 compliance for 2025-2044[48]((for Southern Company, NPV)

Chart Area	Fixed Cost ($B)	Production Cost ($B)	Total System Cost ($B)	Carbon Cost ($B)	System + Carbon Cost ($B)
GCV Base (zonal under 111)	[redacted]				
GPC 111- MG0 (zonal under 111)					

Q. How do the GCV Base portfolio's emissions compare to those of the Company portfolios?

A. Compared to the Company's portfolios, the GCV base results in lower carbon emissions over the period from 2025-2044, in both the EPA 111 compliance scenario and the non-compliance scenario, as illustrated in the figures below.

[48] Fixed costs remain the same for the GCV Base portfolio as in Table 7, as the capital expenditures for the portfolio remain the same, and only the production costs change due to the constraints imposed by EPA 111.

Figure 7: Comparison of Carbon Emissions for GCV Base and GPC Portfolios (Southern Company)

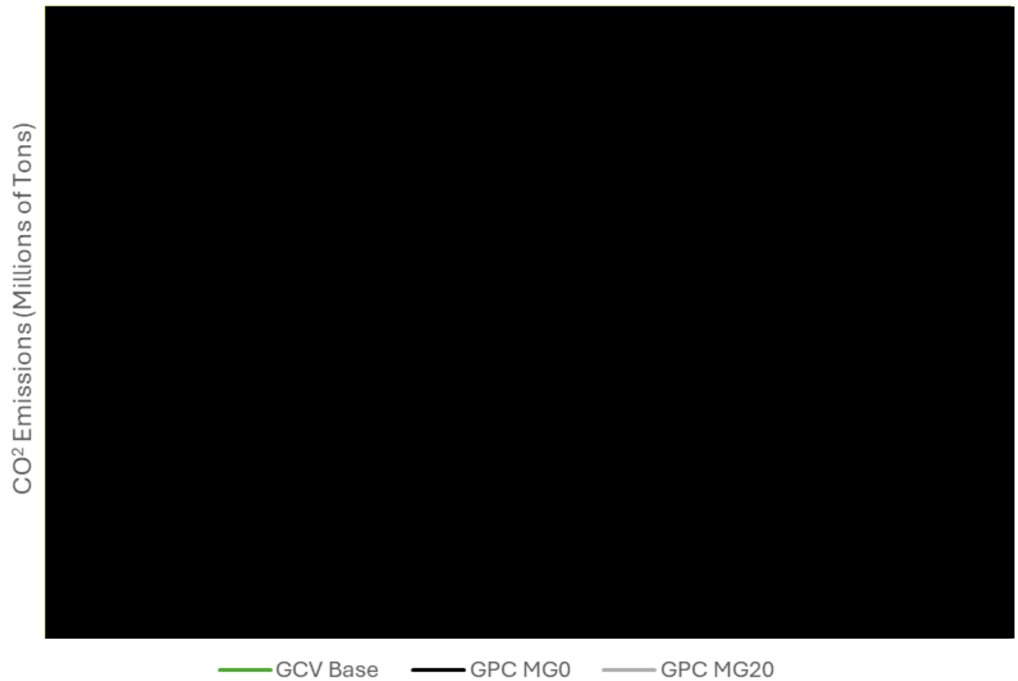


Figure 8: Comparison of Carbon Emissions for GCV Base and 111-MG0 Portfolios assuming EPA 111 compliance (Southern Company)

Q. Have you considered the impacts of gas price volatility on the economics of the portfolios?

A. Yes. Although the company conducts an LTCE for a scenario with higher gas prices, called HG0, which identifies an optimized portfolio for that scenario, this analysis does not identify the risk exposure of the Company's other portfolios to volatile gas prices. To assess the risk posed by volatile fuel prices under the Company's MG0 and 111-MG0 portfolios, I performed production cost runs under the Company's high gas price forecast, simulating the operations of the Company MG0 and 111-MG0 portfolios and the GCV Base portfolio.

Table 9: Comparison of system cost for GCV and Company MG0 Portfolios under high gas prices for 2025-2044 (for Southern Company, NPV)[49]

	Fixed Cost ($B)	Production Cost ($B)	Total System Cost ($B)	Carbon Cost ($B)	System + Carbon Cost ($B)
GCV Base (zonal with high gas prices)	[redacted]				
GPC MG0 (zonal with high gas prices)					

Table 10: Comparison of system cost for GCV and Company 111-MG0 portfolios under 111 operating constraints and high gas prices for 2025-2044 (for Southern Company, NPV)

	Fixed Cost ($B)	Production Cost ($B)	Total System Cost ($B)	Carbon Cost ($B)	System + Carbon Cost ($B)
GCV Base (zonal under 111, with high gas prices)	[redacted]				
GPC 111-MG0 (zonal under 111, with high gas prices)					

The results of the high gas price production cost analysis demonstrate that investing in renewable energy provides a hedge against volatile gas prices, reducing the incremental production costs due to high gas prices (costs that are usually borne by ratepayers, since

[49] Fixed costs remain the same as in Table 7, as the capital expenditures for each portfolio remain the same, and only the production costs change due to the higher gas price.

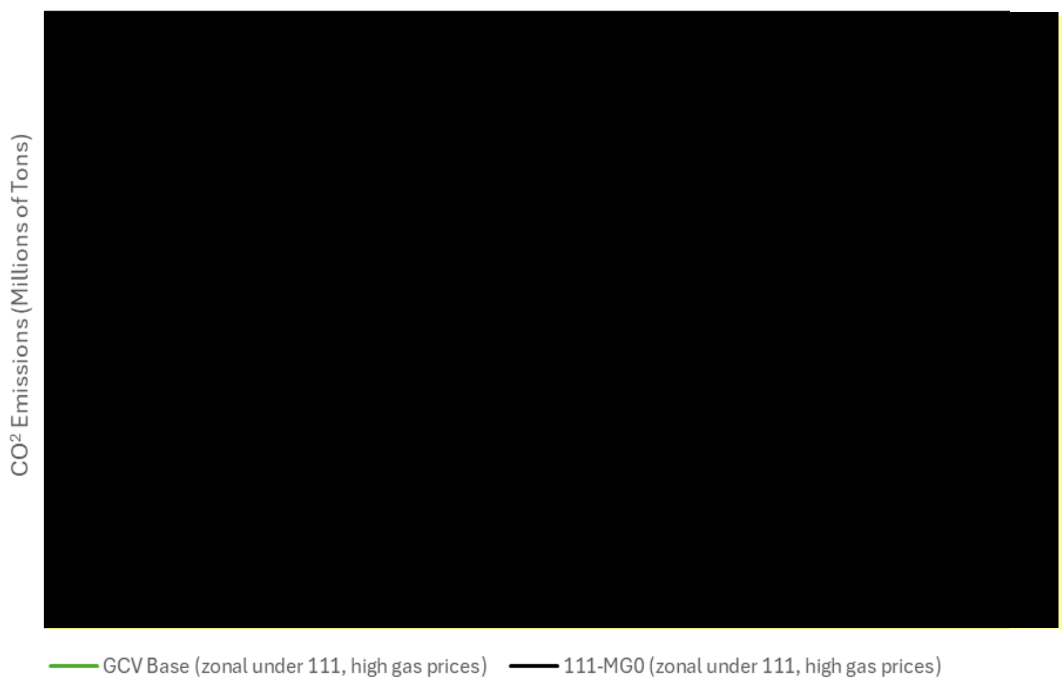
utilities can be made whole recovering fuel costs through power cost riders). The Company portfolios are more exposed to volatile gas prices compared to the GCV base case. The MG0 portfolio, which under medium gas prices had comparable system costs with GCV Base, becomes more expensive once gas prices increase: the cost of MG0 in the high gas price scenario is approximately $2.5 billion greater than that of the GCV Base, while also resulting in an additional cost of $2.1 billion from carbon emissions. The 111-MG0 system cost is more than $8.75 billion greater than the GCV Base, and has $0.75 billion higher carbon costs. It is important to note that although the difference of the carbon costs of the two portfolios is smaller under the 111 scenario, this is primarily a product of applying the 111 operating restrictions on carbon emitting units, especially for the Company portfolios. On the other hand, in the GCV portfolios presented throughout my testimony, emissions reductions are primarily due to higher deployment of renewable energy and results can be relied upon with more confidence as they are less exposed to policy uncertainty.

The emissions of the portfolios are compared in the Figures below:

Figure 9: Comparison of Carbon Emissions for GCV Base and MG0 Portfolios assuming high gas prices (Southern Company)

[redacted]

Figure 10: Comparison of Carbon Emissions for GCV Base and 111-MG0 Portfolios assuming EPA 111 compliance and high gas prices (for Southern Company)



[redacted]

C. Adjusted Load Portfolio

Q. Did you conduct a run under the assumption of a lower large-load adjustment?

A. Yes. Given my concerns about the Company's projection of the load growth, detailed in Section IV, which primarily drive the massive anticipated resource buildout up to 2031, I conducted an additional LTCE run with an adjusted load forecast.[50] Specifically, I developed a least cost portfolio under the assumption that only half of the Company-projected large load growth will materialize (but assuming that load growth driven by other factors will occur). This is consistent with the adjusted large-load forecast presented in Section IV of my testimony.

Q. Please describe the results of the load sensitivity analysis.

A. The optimal resource additions of the adjusted load growth scenario are presented in the table below, in comparison with the GCV Base portfolio, and the Company's 111-MG0. The amount of nameplate capacity additions of each technology is given, once again, for the period of 2025-2033 and 2025-2044.

[50] In this run, I also added the seasonal TRM, consistent with the Company's requested TRM values of 20% Summer and 26% Winter. The Company's model incorrectly applied the Winter TRM as an annual value, requiring a higher reserve margin in summer than the Company proposes to use for its planning purposes. This change should have been applied to all runs but was not due to timing constraints.

Table 11: Comparison of Resource Additions (for Southern Company, in MW Nameplate) for an adjusted load growth scenario

		CT	CC & CC w/ CCS	Solar	Wind	4-hr Storage	12-hr Storage	Nuclear
2025-2033	GCV - Adjusted Load	0	3,300	7,200	1,200	4,740	0	0
	GCV Base	1,200	4,200	10,200	1,200	5,100	1,857	0
	GPC 111-MG0	3,600	5,100	6,900	300	2,700	0	0
2025-2044	GCV - Adjusted Load	4,500	10,500	30,300	4,500	7,896	0	0
	GCV Base	6,000	10,800	33,300	4,500	11,970	1,902	0
	GPC 111-MG0	8,400	13,500	23,400	3,600	6,600	0	600

Compared to GCV Base, the GCV adjusted load portfolio results in lower investment in all resource types by 2033. This is true for every resource type *except wind*, which the model continues to select at its maximum quantity. The model, however, still selects significant amounts of renewable energy and 4-hour energy storage (indicating that these are no regrets resources), much higher than the Company's base portfolio (111-MG0). On the other hand, the GCV adjusted load portfolio reduces gas-fired resources by 5.4 GW by 2033.

Q. Have you assessed the cost and emissions of this portfolio?

A. Yes. I performed production cost runs to assess the cost of this portfolio, as well as the GCV Base and the 111-MG0 under a future with adjusted load. The results of the production cost runs are provided in the table below.

Table 12: Comparison of system cost for GCV and Company Portfolios under an adjusted load growth scenario and 111 operating constraints for 2025-2044 (for Southern Company, NPV)

	Fixed Cost ($B)	Production Cost ($B)	Total System Cost ($B)
GCV - Adjusted Load (zonal under 111, adjusted load)	[redacted]		
GCV Base (zonal under 111, adjusted load)			
GPC 111-MG0 (zonal under 111, adjusted load)			

The first significant result of this analysis is that the portfolio built for adjusted load growth is $10.1 billion dollars less expensive than the Company's 111-MG0 (under the scenario of adjusted load), i.e. over-forecasting load can have significant impacts on ratepayers who will have to cover the cost of overbuilding the system. This demonstrates how significant the impact of getting the load forecast right is, why additional sensitivities should have been conducted, and why the forecasting method warrants close scrutiny.

Another takeaway is that demand-side resources have significant opportunity for reducing resource needs and system costs, as they would be equivalent to a load reduction. A lower load scenario can also be seen as a proxy for aggressive development of demand response, from both large-load customers and aggregated "virtual power plants."

The third takeaway is that renewable energy and energy storage will be used under any future scenario, whether high gas prices, or low load growth, contrary to gas-fired resources which could be left stranded (or produce lower value) either due to economics, policy, or simply lower load growth. For example, an energy storage asset, even under a lower load growth future will result in fixed costs but still deliver value: shift energy from periods of higher prices to periods of lower prices, and result in reduced production costs. In this scenario, the additional solar and storage in the GCV Base continue to drive production costs and emissions lower than the Company 111-MG0. On the other hand, in a lower load scenario, a CT resource would still add fixed costs to the system but would not necessarily operate or provide production cost savings under a lower load growth scenario. Similarly, solar resources will displace energy from other resources (with non-zero marginal costs), while CC resources might not need to generate under a lower growth future. Thus, renewable energy and energy storage can be considered no regrets options.

Finally, energy storage and renewable energy resources have shorter lead-times than the gas resources. Energy storage and renewable energy resources can be procured in closer proximity to the timing of the need, reducing uncertainty in expected loads and providing planning flexibility, while investing in long-lead time, long-lived gas-fired assets can lock the system into a suboptimal path.

D. Coal Retirement Sensitivity

Q. Please describe the coal retirement scenario you investigated.

A. I analyzed the potential for retiring Bowen units 1 & 2 prior to January 1, 2032 within the context of the adjusted load scenario. In this scenario, I also considered the opportunity for additional tax credits that would be available to a medium duration energy storage resource based on the retirement of the coal unit.[51] To model this, I provided the model an additional resource option in the form of a medium duration (12-hour) storage system with reduced fixed costs for build capital expenditure, available immediately following the retirement of Bowen units 1 & 2.

The provided Georgia Power workpapers for Aurora do not include any fixed costs for the existing coal generators but has conducted the unit retirement analysis through calculating expected costs outside of the model, and quantifying energy benefits or production cost savings using the AURORA.[52] This approach does not allow for a comprehensive evaluation of the options in the model, and a model-selected economic retirement. In light of this, I assumed a fixed retirement date before 2032 to avoid necessary expenses associated with compliance with the Supplemental Effluent Limitation Guidelines ("ELG") Rule. Retiring the units prior to 2035 (as modeled by the Company) also results in the avoidance of maintenance and other costs which are not modeled in AURORA.

Q. Please describe the results of the coal retirement scenario.

A. The optimal resource additions for the retirement scenario, which I characterize as the GCV Preferred portfolio, are presented in the table below, in comparison with the GCV adjusted load portfolio and Company 111-MG0. The amount of nameplate capacity

[51] The Energy Community Tax Credit Bonus applies a bonus of up to 10 percentage points (for investment tax credits) for projects, facilities, and technologies located in energy communities. The definition of energy communities includes (among others) a census tract (or directly adjoining census tract) in which a coal-fired electric generating unit has been retired after 2009. For the purposes of this analysis I added both the energy community and the Domestic content bonus credits to a medium duration energy storage resource available for selection after the retirement of the Bowen units (and up to the capacity of the retired Bowen units).
[52] Unit Retirement Study, Technical Appendix Volume I.

additions of each technology is given, once again, for the period of 2025-2033 and 2025-2044.

Table 13: Comparison of Resource Additions (for Southern Company, in MW Nameplate) for GCV's adjusted load, GCV's Bowen 1 & 2 Retirement, and Company 111-MG0 Portfolios.

		CT	CC & CC w/ CCS	Solar	Wind	4-hr Storage	12-hr Storage	Nuclear
2025-2033	GCV - Retire Bowen 1&2 , adjusted load	900	1,500	7,200	1,200	5,100	1,587	0
	GCV - Adjusted Load	0	3,300	7,200	1,200	4,740	0	0
	GPC MG0	3,300	5,400	1,500	300	3,900	0	0
	GPC 111-MG0	3,600	5,100	6,900	300	2,700	0	0
2025-2044	GCV - Retire Bowen 1&2, adjusted load	4,500	8,700	30,300	4,500	8,196	1,704	0
	GCV - Adjusted Load	4,500	10,500	30,300	4,500	7,896	0	0
	GPC MG0	9,900	11,400	18,000	3,600	5,100	900	0
	GPC 111-MG0	8,400	13,500	23,400	3,600	6,600	0	600

Compared to the GCV Adjusted Load portfolio, this retirement portfolio increases the amount of CTs in the near term, as well as 4-hour and 12-hour energy storage resources throughout 2044. It selects equal amounts of solar and wind resources, but reduces the CC capacity in the system; a significant portion of the capacity need from the retirements is met by the medium duration energy storage and then complemented by CTs which are lower cost than CCs. This portfolio indicates the importance of incorporating energy tax credits for eligible resources in the modeling as they can significantly change the relative economics of carbon emitting and clean resources. The resulting system costs are demonstrated below.

Table 14: Comparison of system cost for GCV's adjusted load, GCV's Bowen 1 & 2 Retirement, and Company 111-MG0 Portfolios under adjusted load growth scenario and 111 operating constraints for 2025-2044 (for Southern Company, in MW NPV)[53]

	Fixed Cost ($B)	Production Cost ($B)	Total System Cost ($B)	Carbon Cost ($B)	System + Carbon Cost ($B)
GCV - Adjusted Load portfolio (zonal under 111, adjusted load)	[redacted]				
GCV - Retire Bowen 1 & 2 , adjusted Load (zonal under 111, adjusted load)					
GPC 111-MG0 (zonal under 111, adjusted load)					

VI. Recommendations and Conclusion

Q. What conclusions do you draw from your evaluation of the Company's resource planning process and your modeling analysis?

A. Georgia Power faces a complex resource planning challenge. The uncertainty surrounding its resource need, largely driven by the forecasted large load additions and its ever-increasing TRM is significant and cannot be captured without a robust scenario planning analysis, which the 2025 IRP analysis fails to provide. Both over- and under-forecasting carry risks. For this IRP, after reviewing the Company's load forecasting, resource modeling, and presented plans, I am concerned that Georgia Power is currently planning for an over-forecasted need without sufficiently evaluating the risks.

Furthermore, Georgia Power's analysis relies on resource assumptions for capital expenses, and technology availability that are out of date, erroneous, and uncertain. By

[53] In addition to the AURORA modeled fixed costs, the table includes the revenue requirement for each of the retirement options (which includes fixed, maintenance capital, environmental and conversion costs as reported in the Company's workpaper "2025IRP_AV_BowenU1-4_TRADE SECRET", proportioned for just units Bowen 1&2):
GCV Adjusted Load includes values from "Bowen U1-4: ELG "No Cessation"; ZLD by 12/31/2029" up to 2035
GCV Adjuste Load & Ret Bowen 1&2 includes values form "Bowen U1-4: 111 "Imminent-term"; Retire by 1/1/2032"
111-MG0 include values from "Bowen U1-4: 111 "Medium-term"; Co-fire by 1/1/2030 & Retire by 1/1/2039"

failing to incorporate recent cost increases into the resource costs of new gas-fired units, the Company is underestimating the cost of its presented portfolios by several billion dollars. My analysis demonstrates that updating the capital costs of gas-fired resources as outlined in Section V(A), results in additional costs of more than $6 billion for the Southern Company portfolio, in net present value.

In correcting some of the resource availability and cost assumptions and reoptimizing, I find a better performing portfolio – the GCV Base portfolio – which compared to the Company's proposed 111-MG0 portfolio to meet EPA rule-111 requirements, invests in:

- 3.3 GW less gas-fired resources by 2033 (5.1 GW by 2044),
- 4.2 GW more solar and wind resources by 2033 (10.8 GW by 2044),
- 4.3 GW more energy storage by 2033 (7.3 GW by 2044), and
- (0.6 GW less nuclear by 2044)

When compared to the 111-MG0 portfolio, the GCV base portfolio reduces system and carbon costs by more than $3 billion by 2044 (Southern Company system, NPV).

The higher investment in renewable energy resources in the GCV Base portfolio reduces ratepayers' exposure to volatile high gas prices and the risk of stranded assets. Specifically, in the event of high gas prices, the difference between the GCV portfolio and the 111-MG0 increases to $9.5 billion. On the other hand, if load growth does not materialize at the magnitude and pace expected, the GCV Base portfolio results in net savings when compared to the Company's portfolios. In short, renewable energy and energy storage resources are not only economic under the Company's planning assumptions, but deliver value under a broad range of futures, while the value of gas-fired resources (at the Company proposed scale) quickly diminish if future conditions deviate from the Company's planning assumptions.

Importantly, however, I find that the Company's forecasted large-load growth inflates the projected resource need. When I adjust the Company's load forecast and develop the GCV adjusted load portfolio, this portfolio results in:

- 5.4 GW less gas-fired resources by 2033 (6.9 GW by 2044),
- 1.2 GW more solar and wind resources by 2033 (7.8 GW by 2044),
- 2 GW more energy storage by 2033 (1.3 GW by 2044), and
- (0.6 GW less nuclear by 2044).

When compared to the 111-MG0 portfolio, the GCV Adjusted Load portfolio reduces system costs by more than $10 billion (NPV for the Southern Company system) by 2044.

Finally, when allowing medium duration energy storage resources to receive additional tax credits upon the retirement of the Bowen 1 and 2 units by 2032, the optimal portfolio further displaces gas in favor of energy storage resources:

- 1.5 GW less coal by 2033,
- 6.3 GW less gas-fired resources by 2033 (8.7 GW by 2044),
- 1.2 GW more solar and wind resources by 2033 (7.8 GW by 2044),
- 4 GW more energy storage by 2033 (3.3 GW by 2044), and
- (0.6 GW less nuclear by 2044).

When compared to the 111-MG0 portfolio, the GCV Adjusted Load portfolio that retires the Bowen units 1&2 reduces system costs by nearly $10 billion (NPV for the Southern Company system) by 2044.

It is also worth noting that in every portfolio analyzed, the maximum amount of wind is added in every available year. In spite of this clear preference for wind resources in the planning process, Georgia Power has few wind resources in its current portfolio.[54] While wind resources might be scarce within Georgia, more investigation may be warranted to pursue out-of-state wind resources, especially as the Company itself was assuming double the wind resources were available for selection in its 2023 IRP Update.

Q. Please summarize your recommendations.

A. Georgia Power should increase its planning flexibility and ability to adjust to changing conditions by focusing on (a) supply side resources that can provide benefits under a broad range of future conditions (renewable energy and energy storage), and (b) demand side resources that will increase load flexibility. To ensure this is achieved, my recommendations are:

1. The Commission should not approve the 2025 IRP in its current form and require Georgia Power to revise its analysis to:
    a. Present additional resource portfolios developed based on load growth sensitivities. These should at least include:
        i. Adjusted large-load growth scenarios:
            1. Only large load projects that have signed a "Contract for Electric Service" in the near-term, including a probabilistic analysis or possible delays and reductions in announced load.
            2. Large load projects that have signed a "Contract for Electric Service"

[54] Georgia Power has no company-owned wind and only one power purchase agreement for wind energy, with a nominal capacity of 250 MW. See IRP Attachment C.3 and C.5.

as above plus an increasing percentage of large loads that are in the "Request for Electric Service" stage subject to a similar probabilistic analysis in the longer term.

ii. A low economy growth sensitivity combined with the adjusted large-load growth scenarios.

b. Update the resource costs and availability of gas-fired units based on recent market reports and other utilities' filings in the region.

c. Justify the assumed annual build limits and first year of availability for all resource types and explore under what conditions and costs these could be relaxed, especially for renewable energy and energy storage. The analysis should at least investigate whether the following are feasible and under what conditions:

i. An earlier first year of availability and higher cumulative limit for wind resources.

ii. An earlier year of availability for medium and long duration energy storage.

iii. A higher annual build limit for solar resources.

As part of the analysis, the Company should:

- Investigate wind resource availability and barriers to successful procurement of new wind resources (such as transmission investments and procurement design).

- Provide an analysis of the potential of co-locating clean resources to share the same point of interconnection with operating thermal units with low capacity factors, as well as using existing interconnection from retired or soon-to-be retired units to interconnect clean resources.

- Analyze the potential of installing energy storage (including medium and long duration options) at existing/retired plants to take full advantage of investment tax credits (and include such credits in the resource analysis).

d. Include the modeling of seasonal TRM values.

e. Determine and model seasonal Effective Load Carrying Capabilities ("ELCC") values for all resources (including thermal units).

f. Retire Bowen 1&2 prior to 2032. Continue investigating the retirement of all coal units prior to 2032 and postpone actions to co-fire at this time.

2. The Commission should also require Georgia Power to take certain actions going forward as it prepares for future IRPs and RFPs. In addition to the recommendations in (1):

a. Increase the accuracy and transparency of its forecasting process to ensure more accurate forecasts are used in the Company's planning analysis in the IRP, as well as in procurements in upcoming RFPs:

i. Continuously update the probabilities assumed in the Load Realization Model based on the changes reported in its quarterly large load economic development filings.

ii. Ensure no double counting between the econometric base forecast and the large load adjustment.

b. Collect and track additional information for the Company's large load pipeline, including the time between one stage to the next, reasons for delays or changes in status, information on the portion of the large loads with clean energy commitments. Include such information in the Company's quarterly Large Load Economic Development reports.

c. Develop a more robust scenario analysis framework that will evaluate the performance of each portfolio the company presents under a broad range of possible futures, including a broad range of load forecasts.

d. Continue to evaluate coal retirement options for all remaining units prior to 2035.

e. Continue to evaluate opportunities to enhance and expand all customer programs that could further reduce net load and resource needs. Given the projected capacity need, particular focus should be given to improving and increasing customer participation in:

    i. Large load customer programs and tariffs like the Large Customer Owned Resiliency Program, the DPEC interruptible tariff, the Curtailable Load tariff, the consideration of a clean transition tariff,

    ii. Other demand response programs, such as the Residential Thermostat Demand Response program.

Q. Does that conclude your testimony?

A. Yes.

VERIFICATION

There undersigned, Maria Roumpani, Phd., affirms under the penalties of perjury that the answers in the foregoing Direct Testimony in Docket No. 56002 & 56003 before the Georgia Public Service Commission are true to the best of her knowledge, information and belief.

/s/ Maria Roumpani
Maria Roumpani
Current Energy Group, LLC.

MR-1:

RESUME OF MARIA ROUMPANI

Maria Roumpani

Partner, mroumpani@currentenergy.group

Professional Summary

Maria is an expert in energy system planning and an energy modeler. She focuses on the economic and technical analysis of grid planning and operations issues and has experience in capacity expansion optimization, production cost simulations, and energy storage dispatch modeling. Maria has submitted expert testimony and comments on integrated resource planning, plant economics, unit commitment practices, power cost issues, and demand side management plans. Her clients include consumer advocates, public interest organizations, energy project developers, government agencies, and large energy buyers.

Education

PhD, Management Science & Engineering
Stanford University, 2018

MSc, Electrical and Computer Engineering
National Technical University of Athens, 2009

Work Experience

Founding Partner, Current Energy Group, (May 2024 – Present)

- Founding partner specializing in the economic and technical analysis of grid planning and operations issues, including capacity expansion, production cost, and energy storage dispatch modeling.

Founder, ELO Engineering Consulting (March 2024 – May 2024)

- Conducted analysis on energy policy and economic issues.

Technical Director | Strategen Consulting (2018 – March 2024)

- Led firmwide technical and economic modeling and analysis to support consulting engagements. Specialized in the use of modeling tools to inform grid planning and decarbonization issues.

Research Assistant | Precourt Institute for Energy, Stanford University (2011 – 2017)

- Conducted research in a wide range of topics, from game theoretical approaches in electricity markets to behavioral economics.

Researcher | Energy, Economics, & Environment Modeling laboratory, National Technical University of Athens, (2009-2010, 2015)

- Contributed to the development of long-term energy planning models.
- Developed a wholesale electricity market competition model.

Expert Testimony

Virginia Electric and Power Company's 2024 Integrated Resource Plan
on Behalf of Advanced Energy United
Virginia State Corporation Commission
Case No. PUR-2023-00066
Testimony

East Kentucky Power Cooperative, Inc. Application for Approval of Demand Side Management Tariffs
on Behalf of Joint Intervenors Appalachian Citizens' Law Center, Kentuckians for The Commonwealth, and Mountain Association
Kentucky Public Service Commission
Case No. 2024-00370
Testimony

NV Energy and Sierra Pacific Power Company 2025-2044 Integrated Resource Plan
on behalf of Advanced Energy United
Public Utilities Commission of Nevada
Docket No. 24-05041
Testimony

Duke Energy Carolinas and Duke Energy Progress 2023 Integrated Resource Plans
on behalf of Sierra Club, South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, Upstate Forever, and Vote Solar
Public Service Commission of South Carolina
Docket No. 2023-8-E & No. 2023-10-E
Testimony

Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, and Duke Energy Progress,
on behalf of the Southern Alliance for Clean Energy, Sierra Club, Natural Resources Defense Council, and North Carolina Sustainable Energy Association
North Carolina Utilities Commission
Docket E-100, Sub 190
Testimony

Annual Review of Base Rates for Fuel Costs of Dominion Energy South Carolina, Inc.
on behalf of the South Carolina Office of Regulatory Staff
Public Service Commission of South Carolina
Docket No 2023-2-E
Testimony

Annual Review of Base Rates for Fuel Costs of Duke Energy Progress, LLC
on behalf of the South Carolina Office of Regulatory Staff
Public Service Commission of South Carolina
Docket No 2023-1-E
Testimony

Virginia Electric and Power Company 2023 Integrated Resource Plan
on behalf of Advanced Energy United
Virginia State Corporation Commission
Case No. PUR-2023-00066
Testimony

PacifiCorp's Transition Adjustment Mechanism
on behalf of Sierra Club
Oregon Public Utilities Commission
Docket No. UE 420
Testimony

DTE 2022 IRP
on behalf of the Michigan Energy Innovation Business Council
Michigan Public Service Commission
Case U-21193
Testimony

Duke Energy Carolinas and Duke Energy Progress 2022 Carbon Plan
on behalf of the Tech Customers
North Carolina Utilities Commission
Docket E-100, Sub 179
Testimony

Public Service Company of Colorado
on behalf of Sierra Club
Colorado Public Utilities Commission
Proceeding No. 21A-0141E
Testimony