PUBLIC VERSION

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

GEORGIA POWER COMPANY'S 2023 INTEGRATED RESOURCE PLAN UPDATE	**)** **)** **)**	**DOCKET NO. 55378**

DIRECT TESTIMONY AND EXHIBITS

OF

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ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

FEBRUARY 15, 2024

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I. BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAMES, TITLES, AND BUSINESS ADDRESSES.

A. My name is Tom J. Newsome. I am the Director of Utility Finance with the Georgia Public Service Commission ("Commission"). My business address is 244 Washington St., Atlanta, Georgia 30334.

My name is Philip M. Hayet. I am the Vice President and a Principal of J. Kennedy and Associates, Inc. ("Kennedy and Associates"). My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

My name is Leah J. Wellborn. I am a Manager of Consulting at Kennedy and Associates. My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

Q. MR. NEWSOME, WHAT ARE YOUR PRIMARY RESPONSIBILITIES WITH THE COMMISSION STAFF?

A. I am responsible for economic, financial, and cost of equity analysis and evaluations at the Commission.

Q. WHAT CONSULTING SERVICES DOES KENNEDY AND ASSOCIATES PROVIDE?

A. Kennedy and Associates provides consulting services related to electric utility system planning, resource analysis, production cost modeling, ratemaking, finance, accounting, and industry policy issues.

Q. PLEASE PROVIDE SUMMARIES OF YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. Summaries of our education, experience, professional certifications, and testimony appearances are provided in Exhibits STF-NHW-1, STF-NHW-2, and STF-NHW-3, for Mr. Newsome, Mr. Hayet, and Ms. Wellborn, respectively.

Q. HAVE YOU ALL PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. Yes, we have all testified before this Commission.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. We are presenting testimony on behalf of the Georgia Public Service Commission's ("GPSC" or "Commission") Public Interest Advocacy Staff ("Staff").

Q. PLEASE OUTLINE THE ROLES STAFF AND ITS CONSULTANTS PLAYED IN THIS PROCEEDING.

A. The primary focus of this panel has been to address Georgia Power Company's ("Georgia Power" or "Company") supply-side capacity requests. Staff and its other consultants evaluated Georgia Power's Distributed Energy Resource ("DER") tariff proposal and Demand Side Management ("DSM") program modification requests. Daymark evaluated Georgia Power's proposed load forecast and transmission load flow analyses, Grid Strategies considered the Company's transmission requests along with the need to integrate renewable resources, and Larkin Associates evaluated the Company's financial regulatory requests.

II. FINDINGS AND RECOMMENDATIONS

Q. WHAT ARE GEORGIA POWER'S SPECIFIC REQUESTS IN THIS PROCEEDING?

A. Georgia Power's requests are presented in the Summary Section of the 2023 IRP Update Main Document, beginning at page 28 and are repeated here. The specific items that this panel addresses are shown in **bold** text.

1. ***Authorization to procure the supply-side resources described in items 2-6 and 9 below in accordance with Commission Rules through the exceptions to the Commission's RFP process set forth in Commission Rules 515-3-4-.04(3)(f)(3), 515-3-4-.04(3)(f)(6), and 515-3-4-.04(3)(f)(7).***

2. ***A certificate of public convenience and necessity for the PPA Between Georgia Power Company and Mississippi Power Company as described in Attachment A and the Technical Appendix.***

    a. Regulatory asset treatment to defer the capacity and non-fuel energy payments made under the PPA, including additional sum, net of the wholesale capacity and non-fuel revenues from any remarketed capacity sales from January 1, 2024, through December 31, 2025, including an executed system sale to a regional electrical service provider during that time, for recovery in the next base rate case.

3. ***A certificate of public convenience and necessity for the PPA Between Georgia Power Company and Santa Rosa Energy Center LLC as described in Attachment B and the Technical Appendix.***

    a. Regulatory asset treatment to defer the capacity and non-fuel energy payments made under the PPA, including additional sum, net of any wholesale capacity and non-fuel revenues from any remarketed capacity sales from January 1, 2024, through December 31, 2025, for recovery in the next base rate case.

4. ***Authority to develop, own, and operate up to 1,000 MW of BESS at various sites as described in this IRP Update and the Technical Appendix.***

   a. *Approval that any development costs not useful or transferable to other projects be deferred to a regulatory asset for recovery in the next base rate case in the event this request is denied.*

5. ***Authority to develop, own, and operate up to 1,400 MW from three simple cycle CT resources at Plant Yates as described in this IRP Update and the Technical Appendix.***

   a. *Approval that any development costs not useful or transferable to other projects be deferred to a regulatory asset for recovery in the next base rate case in the event this request is denied.*

6. *Approval of two new customer-sited DER programs as described in this IRP Update.*

7. *Approval of one new tariff-based demand response program as described in this IRP Update.*

8. *Approval of an amended certificate for one existing demand response DSM program as described in this IRP Update and Attachment C.*

9. ***Approval of the Flex Capacity framework as described in the Flex Capacity section.***

   a. *Regulatory asset treatment to defer any developmental costs for such activities that would otherwise be expensed for recovery in the next base rate case.*

10. *Expansion of the transmission system to accommodate the above-requested resources and the Company's Load and Energy Forecast as described in the Technical Appendix.*

Q. PLEASE SUMMARIZE THIS PANEL'S FINDINGS AND RECOMMENDATIONS.

A. Our findings and recommendations are:

1. Based on Staff's load forecast and Target Reserve Margin ("TRM") assumptions, Staff agrees there is a need for additional capacity, beginning in 2027 and subsequent years to meet winter peak demands.[1] Staff recommends approval of the Mississippi Power Company ("MPC") Power Purchase Agreement ("PPA") and the Santa Rosa PPA to mitigate reliability risk, as these resources are the only ones currently in operation certain to be available at the time of the 2027 winter peak period.

2. Staff's Proposed Plan recommends approval of the MPC and Santa Rosa PPAs, which results in the Company's next need date for additional capacity occurring in 2029.

3. Staff recommends the Commission direct the Company to expedite its currently ongoing Request For Proposals ("RFPs"), the 2029-2031 All-Source RFP and the 500 MW Energy Storage System ("ESS") RFP, to provide for competitive procurement of additional resources to meet the need in 2029 but expand the start date of resource selection to begin as early as 2027. Staff believes that by accelerating the ongoing competitive processes, the Company and Commission could assess the economic merit of all proposed resources, and all start dates in the widened time band.

4. Staff recommends that the Commission deny the Company's request for certification of the Yates Combustion Turbine ("CT") Units 8, 9, and 10. The Yates capacity is not required until 2029 and should be bid into the 2029 – 2031 capacity RFP to determine whether this capacity is least-cost and the most reliable compared to other options.

5. Staff recommends the Commission deny the Company's request for approval of the proposed Moody and Robins BESS projects, and the Co-located BESS/Solar resources. This capacity is not needed until 2029 and these resources should be bid into the 2029 – 2031 All-Source capacity RFP and/or the 500 MW ESS RFP to determine whether these resources are least-cost and the most reliable compared to other options.[2]

[1] The 2027 winter peak includes possible peak demands in December 2026.
[2] The Company's Request For Information ("RFI") provided with the Supplemental Filing provides evidence of the availability of BESS PPA resources at potentially lower cost than the Company's proposed self-build options.

6. Staff recommends the Commission not give blanket approval for 1,000 MW of Company developed BESS capacity at this time. Staff recommends that new BESS resources be selected based on a competitive procurement process, such as the 2029 - 2031 All-Source capacity RFP or the 500 MW ESS as approved in the 2022 IRP.

7. Staff recommends the Commission deny the Company's request for approval of the Flex Capacity Framework, which could authorize the Company to develop even more capacity without going through a competitive solicitation process. This capacity is not needed until 2029 and should be bid into the 2029 – 2031 capacity RFP and/or the 500 MW ESS RFP to determine whether the capacity is a least-cost option.

8. Staff's independent Aurora Resource Mix Study tested the validity of the Company's proposed resource additions. The results indicate that the proposed Company-owned BESS, BESS plus Solar, and CT projects are not economic in 2027 and would not be selected as part of an optimal mix study, given the availability of lower cost generic resource alternatives. This supports Staff's recommendation that Company-owned resources should be evaluated in a competitive RFP process.

9. In the 2022 IRP (Docket No. 44160), the Company proposed a 26% System winter TRM while Staff proposed 24.5%. The Commission postponed a decision on the TRM to a later time when new resources would actually have to be acquired, though the Commission stated that no party would be foreclosed from presenting arguments for a TRM in a future IRP. Staff used a 24.5% TRM for this IRP.

10. Staff recommends the Company perform a new TRM study in the 2025 IRP that incorporates the Load Realization Model ("LRM") impacts as an evaluated variable along with other variables already modeled by the Company (weather, load forecast error, and outages).

11. Staff finds that the Company's notice of the 70% rule for owned capacity should not be considered as part of the rationale for acquiring Company-owned resources in this proceeding. The 70% rule should be evaluated separately outside of the context of this "extraordinary" load growth dominated IRP proceeding to consider impacts on ratepayers.

12. The Company provided an Economic Analysis of Capacity Resource Study ("Economic Analysis Study")[3] to support approval of its proposed contracts and resource additions. Staff finds the Company's study was deficient due to the Company's overstated load forecast, failure to consider PPA options, use of outdated fuel and carbon tax forecasts, and other problems.

13. In the event the Commission does not accept all the Staff recommendations, and determines more capacity is required earlier, Staff presents a ranking of the proposed Company-owned resources to guide the selection of approved resources. However, Staff continues to believe a competitive procurement process such as an RFP, is the best means to rank and evaluate the Company's proposals against market alternatives.

14. Given the significant impact new large customers loads could have on other customer classes, Staff recommends the Company file a Cost of Service Study in rebuttal testimony consistent with the Company's requests in this 2023 IRP Update to quantify the rate impacts on all customer classes. Furthermore, the Company should be required to file a Cost of Service Study with its 2025 IRP filing to demonstrate potential rate impacts considering all costs on all customer classes consistent with the Company's proposed 2025 IRP plan.

Q. WHAT LED THE COMPANY TO FILE ITS 2023 IRP UPDATE?

A. Georgia Power states that since the 2022 IRP was approved by the Commission in its Order issued on July 29, 2022, Georgia has experienced "extraordinary growth [that] requires Georgia Power develop new supply- and demand-side capacity resources to meet substantial increases in customer demand and energy needs of our state."[4] The Company believes it will require quick action on the part of the Commission to enable Georgia Power to serve these new large customer loads when they are ready for operation.

[3] Technical Appendix, Section 9.
[4] Direct Testimony of Jeffrey Grubb, Francisco Valle, Lee Evans, and Michael Bush, Docket No. 55375, December 4, 2023, ("Georgia Power Direct Testimony"), p. 6, l. 5.

According to the Company, the dramatic increase in load accelerates the Company's need for capacity resources. At the time of the 2022 IRP, the Company projected it would have a capacity need in the winter of 2028/2029, but now the Company is projecting that it will have a capacity need three years earlier, in the winter of 2025/2026. Georgia Power has identified resources to satisfy the earlier capacity need. Georgia Power is required to conduct an RFP process; however, the Company is seeking an exception to that requirement pursuant to the Commission's IRP Rules 515-3-4-.04(3)(f)(3), (6) and (7). Rule 515-3-4-.06(5) requires an amended IRP be filed when Georgia Power anticipates acquiring a resource that will be excepted from an RFP process, which is the subject of this proceeding.

Q. WHAT IS STAFF'S UNDERSTANDING OF THE EVENTS THAT HAVE OCCURRED RELATED TO THE SIGNIFICANT GROWTH IN THE LOAD?

A. The following timeline provides Staff's understanding of the events that occurred around the time the Company became aware there would be significant growth in large customer loads:

- ***January 31, 2022*** – Georgia Power filed the 2022 IRP.
- ***March 2022*** – By the end of March 2022, Georgia Power knew that [redacted] of large customer loads had selected to be served by Georgia Power.[5]

[5] STF-JKA-4-9 Attachment.xlsx

- ***July 29, 2022*** – The 2022 IRP was approved, and the Company was ordered to conduct an All-Source RFP for winter of 2029-2031 resource needs.
- ***December 2022*** – By the end of December 2022, Georgia Power knew that an additional [redacted] MW of Economic Development Load had been selected to be served by Georgia Power.[6]
- ***March 2, 2023*** – Staff reached out to Georgia Power for an update on when the All-Source RFP would be issued. On March 29, 2023, the Company communicated to Staff it would provide an update no later than June 2023 of its plans, including its proposed RFP schedule to meet winter 2029 – 2031 needs.
- ***June 27, 2023*** – Georgia Power met with Staff and discussed the All-Source RFP and load forecast increase, which led to an earlier capacity need year. Georgia Power first notified Staff of the large increase in customer choice load at this meeting.
- ***July 10, 2023*** – Georgia Power met with Staff and continued All-Source RFP and load forecast discussions with Staff.
- ***August 2, 2023*** – Georgia Power met with Staff to discuss the Company's plans and schedule for the of upcoming 2023 IRP Update and continue discussions regarding the 2029-2031 All-Source RFP. On August 22, 2023, Staff proposed to the Company a schedule for the 2029 – 2031 All-Source RFP that would expedite the RFP and expand the time period when capacity could be acquired to cover December 1, 2025 to the end of 2031.
- ***September 12, 2023*** – Georgia Power met with Staff to discuss final capacity needs that would be addressed in the 2023 IRP, and continued discussions regarding the 2029-2031 All-Source RFP. Staff continued to advocate for the 2029-2031 All Source Capacity RFP to be expedited and expanded to 2027-2031.
- ***October 27, 2023*** – Georgia Power filed the 2023 IRP Update.

Q. HOW DID THE TIMELINE ABOVE IMPACT THE COMPANY'S REQUEST IN THIS PROCEEDING?

[6] *Id.*

A. The Company was aware of an increase in new load in the first half of 2022 and won significantly more load in the second half of 2022. Given the large increase in load in 2022, the Company should have started the capacity RFPs approved by the Commission in the 2022 IRP Order earlier such as in January 2023 rather than December 2023. An earlier start of the RFPs would have provided an opportunity to test the Company's self-build generation proposed in this filing against the market and could have resulted in market proposals for the Commission's consideration in the 2025 IRP.

Q. IS GEORGIA POWER REQUIRED TO FILE AN AMENDED IRP WITH THE SAME AMOUNT OF DETAIL AS IS REQUIRED IN A FULL IRP?

A. No, as the Commission's Procedural and Scheduling Order ("PSO") states, "Commission Rule 515-3-4-.06(6) provides that the Commission may limit the scope of issues it will consider in the review of subsequent plans to those issues directly related to material changes."[7]

III. RESOURCE NEED AND RFP TIMELINE

Load Forecast and Need Date

Q. HOW DID THE COMPANY'S LOAD FORECAST CHANGE BETWEEN THE 2022 IRP AND THE 2023 IRP UPDATE?

[7] Georgia Public Service Commission Procedural and Scheduling Order, Docket No. 55378, November 21, 2023, p. 5.

A. The Company's latest load forecast is significantly higher than what the Company forecast in the 2022 IRP, as seen in the following table.

Table 1: Company Winter Peak Forecast Comparison
2022 IRP vs 2023 IRP Update

MW	2024	2025	2026	2027	2028	2029	2030
2022 IRP	15,581	15,636	15,657	15,674	15,659	15,760	15,799
2023 IRP Update P95	15,283	15,947	17,256	18,928	19,751	20,551	21,326
Delta	-298	311	1,599	3,254	4,092	4,791	5,527

Q. WHAT CAPACITY NEED HAS THE COMPANY IDENTIFIED IN THE 2023 IRP UPDATE?

A. The following table presents the Company's load, total capacity resources, and capacity need that the Company identified in the 2023 IRP Update (without new proposed resources). The Company developed a new probabilistic model to evaluate the likelihood of new economic development load being added to Georgia Power's system. As discussed in more detail by the Daymark Panel, the Company's forecast, including new large customer loads, is referred to as the P95 forecast, which essentially assumes that with respect to the new large customer loads, there is only a 5% chance that the load could possibly exceed the identified forecast. In the 2022 IRP, the Company determined that its need for additional capacity would not occur until 2029, while in this 2023 IRP Update, the Company has determined that its need for additional capacity resources has

advanced by three years to 2026, as seen in the following table.[8]

Table 2: Georgia Power's Load and Resource Balance without Proposed Resources [9]

Year	Peak Demand (MW)	Total Capacity (MW)	Capacity Required to Meet GPC Target (MW)	GPC Reserve Margin (%)
2024	15,283	19,980	(964)	30.7%
2025	15,947	21,196	(1,352)	32.9%
2026	17,256	21,296	175	23.4%
2027	18,928	21,785	1,875	15.1%
2028	19,751	22,088	2,601	11.8%
2029	20,551	20,882	4,807	1.6%
2030	21,326	20,885	5,774	-2.1%
2031	21,880	18,864	8,487	-13.8%
2032	22,141	18,901	8,776	-14.6%
2033	22,353	18,883	9,059	-15.5%
2034	22,515	18,917	9,228	-16.0%
2035	22,630	16,948	11,340	-25.1%

The "Total Capacity" column contains all Georgia Power firm capacity resources, including PPAs with third parties and Demand Side Options ("DSO"), and accounts for certain resources on an equivalent capacity basis.

Q. WHAT EVALUATION HAS STAFF PERFORMED OF THE COMPANY'S LOAD FORECAST?

[8] In Table 2, positive values for the line – "Capacity Required to Meet GPC Target" means the Company has a capacity need.
[9] Based on STF-JKA-2-2 Supplemental Attachment B.xlsx without proposed resources.

A. Daymark evaluated Georgia Power's load forecast, and derived Staff's load forecasts which were used by this panel to develop Staff's recommendations regarding acquiring additional capacity. The two forecasts this panel relied on are referred to as the "Uniform w/ Delays P95" forecast and the "Uniform w/ Delays P80" forecast. Many utilities provide a range of forecasts that are independent of fuel and carbon assumptions. Consistent with this notion, Staff's Uniform w/ Delay's P95 case is Staff's "base" case forecast, and Staff's Uniform w Delay's P80 is Staff's "low" forecast, while the Company's P95 scenario reflects a "high" sensitivity case.

Staff's adoption of the "Uniform w/Delays P95" load forecast is described by the Daymark panel, and is supported by the Company's broad definition of "won" loads. The great majority of the "won" loads / customers have not signed anything more than a "Request For Service" agreement, which obligates the customers to take service from Georgia Power if they decide to construct and operate the new facility. Very few of the "won" load customers have signed more formal Contract for Electric Service, Customer Baseline Load Agreement and Meter Totalization Term and Condition agreements with Georgia Power. This absence of signed formal and binding agreements between "won"

load customers and Georgia Power supports Daymark's forecast of slower growth in load.[10]

Q. DOES STAFF AGREE THAT THE COMPANY HAS A NEED FOR NEW CAPACITY RESOURCES BY THE WINTER OF 2025/2026?[11]

A. No. The Company's assertion is that based on its load forecast, it will have a need for additional capacity resources to meet the winter of 2025/2026 peak demand forecast, which is three years earlier than the need date the Company identified in the 2022 IRP. Staff agrees that the Company will have an earlier need date for additional capacity resources than what was identified in the 2022 IRP; however, Staff has found that based on its revised load forecast, the Company's need date may advance by two years, not three. Based on this analysis, Staff has found that only some of the resources the Company has identified will be required, specifically the MPC and Santa Rosa PPAs. The remainder of the resources the Company has identified can be postponed, and if they are found to be economic in a competitive solicitation process, they could be acquired later.

Q. HAS STAFF DEVELOPED ALTERNATIVE LOAD AND RESOURCE TABLES?

A. Yes, Exhibit NHW-4 provides an alternative view of the Company's Load and Resource

[10] See STF-JKA-4-7 and STF-DEA-4-7.
[11] Note, while Georgia Power has a need for resources in Jan 2026 to meet its TRM requirement, the System is actually long on resources 2026, and the first year the System has a need for resources is 2027.

tables, and Staff's Proposed Plan reflects the load forecast and other alternative assumptions Staff has identified, including a revised TRM, alternative assumptions for existing resources, and Staff's recommendation for resources that the Company could acquire to satisfy its resource needs.

In addition to these differences in loads and resources, Staff Witness Kaduk also evaluated the Company's request for additional demand side tariffs (DCL, DCO, CL). Staff's forecast in Exhibit NHW-4 has assumed that the new and amended demand response programs, and the two new customer-sited distributed energy resource ("DER") programs, will provide only a minimal amount of capacity. Nevertheless, Staff believes demand response and DER programs could play a greater role in meeting the Company's resource needs. It is conceivable that the Residential TempCheck program capacity could double and that the Clean and Renewable Energy Subscription ("CARES") RFP could identify hundreds of MW of capacity in the form of 2-hour BESS collocated with solar.[12]

Q. EXHIBIT NHW-4 CONTAINS THREE DIFFERENT TABLES, PLEASE DESCRIBE THE DIFFERENCES BETWEEN THEM.

A. Table A contains Staff's view of the Company's load and resource balance table without new resources based on Staff's assumptions for load, TRM, and other changes, which shows that the Company has a small need for resources of 143 MW in 2027. Table B

[12] See STF-PIA 9-14

contains Staff's Proposed Plan, which accounts for future capacity in the pipeline (RFP renewable and BESS capacity and the possibility to extend Scherer and Gaston) as well as Staff's recommendation for approval of only the MPC and Santa Rosa PPAs. According to Staff's Proposed Plan, after acquiring MPC and Santa Rosa, the Company's next need for capacity moves to 2029 (winter 2028/2029), which will allow time for RFPs to be conducted and resources identified based on competitive procurement processes. This also assumes the Company's 2022 IRP procurements (2029 – 2031 All-Source, ESS and Renewable RFPs) would be issued and identify the Company's future capacity resources.

Table C contains an illustrative case (not part of Staff's Proposed Plan) that Staff performed assuming a P80 load forecast and selection of the MPC PPA resource only, which will be described in further detail in the Staff Ranking Analysis section below (Section V).

Reserve Margin

Q. IN THE 2022 IRP, STAFF TOOK ISSUE WITH THE COMPANY'S TRM. PLEASE SUMMARIZE STAFF'S FINDINGS AND RECOMMENDATIONS

FROM THAT IRP.[13]

A. Staff summarized its findings in testimony it filed in the 2022 IRP as follows:

- The Company recommended dual Southern Company System Planning Target Reserve Margins ("TRM") of 16.25% for the summer and 26% for the winter. Even though the Southern Company system is summer peaking, the higher winter TRM provided more than sufficient reliability to meet a 16.25% Summer TRM.

- The Staff's analysis of the Company's Reserve Margin Study found the Company's study overstated the optimal winter TRM. Staff determined that a Long-Term winter TRM of 24.5% would provide capacity sufficient to meet the Company's proposed reliability standard[14] thereby providing the same level of reliability as proposed by the Company. The Staff did not object to continuation of a 16.25% summer Long-Term TRM, as proposed by the Company.

- The Staff also accepted the Company's recommendation to reduce Short-Term winter and summer TRMs by 0.5% as compared to the Long-Term TRMs. This results in a Short-Term winter TRM of 24% and a summer TRM of 15.75%.

Q. DID THE COMMISSION APPROVE STAFF OR THE COMPANY'S TRM RECOMMENDATION IN THE 2022 IRP PROCEEDING?

A. The Commission did not reach a conclusion regarding either of the TRMs in the 2022 IRP. The Stipulation in Docket No. 44160 left this issue up to the Commission to decide at a later time, as explained in the following discussion from the Commission Order:

> There is no requirement for the Commission to act upon the winter TRM request at this time. The Company may propose resource additions in the

[13] Georgia Power discussed its reserve margin study in the 2022 IRP in the report entitled, "An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System," Docket No. 44160, January 2022.

[14] A Value at Risk level ("VaR") of 80%

> next IRP, if needed, to meet winter TRM, and the Commission can determine at that time the appropriate winter TRM and whether such additional capacity is needed. Use of the 26% winter TRM for planning purposes is not an endorsement by the Stipulating Parties of that TRM, and no Stipulating Party is foreclosed from proposing an alternative winter TRM in a future case.[15]

Q. PLEASE EXPLAIN WHY STAFF AND THE COMPANY DISAGREED ON WHICH TRM TO USE.

A. As mentioned above, in the 2022 IRP, Staff contended the Company's 26% winter TRM was overstated and should have only been 24.5%. Staff determined that the overstatement was attributed to the Company's unreasonable derivation of a load forecast error ("LFE") distribution table that was used in the Strategic Energy and Risk Valuation Model ("SERVM") reliability analysis that the Company performed. The LFE distribution table was derived from 18 years of system energy forecasts that were compared to actual weather normalized energy requirement results in the fourth year of the forecast. Because the actual load forecast errors over the past 18 years showed the Company had consistently over-forecast load, the Company elected not to use the actual data to develop its SERVM LFE distribution table. Instead, the Company made an ad-hoc adjustment, in which it subtracted the median percentage forecast error from the actual forecast error each year. Staff found this to be inconsistent with any statistical modeling practice.

[15] Commission Order in Georgia Power's 2022 IRP, Docket No. 44160, July 29, 2022, par. 16, p. 17.

Q. WHAT CORRECTION DID STAFF MAKE TO THE COMPANY'S TRM ANALYSIS?

A. Staff did not have access to the Company's SERVM Model, but was able to make an adjustment that approximated the analysis that could have been performed with SERVM. Since there were no over-forecasted errors, just under-forecasted errors in the past 18 years, Staff applied a "0" probability to the over-forecast scenarios associated with the SERVM results and was able to derive recalculated SERVM results.

Q. HOW DID THE COMPANY RESPOND TO STAFF'S ADJUSTMENT RECOMMENDATION?

A. Georgia Power responded in Rebuttal Testimony that the Company had only over-forecasted peak demand in recent years, which does not mean it would over-forecast its load in future years.[16] The Company also asserted that it would be inappropriate and unwise to only consider over-forecast situations for future load. There are a few problems with the Company's Rebuttal Testimony. The Company did not address the criticism and flaws Staff found with its modeling approach. It is indisputable that the Company made an ad-hoc adjustment, and it had no basis for subtracting the median percentage forecast error from the actual forecast error each year. That was a manufactured calculation to

[16] Direct Testimony of Jeffrey Grubb, A. Wilson Mallard, Michael Robinson, and Jeffrey Weathers, Docket No. 44160, May 6, 2022, p. 6, l. 23.

achieve the LFE distribution the Company desired without basing the results on any historical evidence. Furthermore, the Company's statement that it had only over-forecasted peak demand in recent years was inaccurate as the Company has over-forecasted its weather normalized load every year for the past 18 years. It is appropriate to require the Company to derive the TRM based on a reasonable analysis that considers facts and historical evidence, not based on a made up calculation that the Company cannot support.

Q. WHAT IS STAFF'S RESERVE MARGIN RECOMMENDATION?

A. Staff continues to recommend that the Company use the corrected value of 24.50% as the System long-term winter TRM. This is particularly important, given the Company's election to use the P95 LRM forecast for the large customer loads, which implies there is just a small chance it has under-forecast its load (5%).

Additionally, Staff recommends that in the 2025 IRP, when the Company updates its TRM study, it should incorporate an additional risk variable in its SERVM modeling to address the uncertainty associated with materialization of new large customer loads, which would be in addition to the other uncertainty variables the Company is already modeling, including weather, load forecasting error, and outages.

Q. HOW DOES GEORGIA POWER USE THE TRM RESULTS IN ADDRESSING ITS CAPACITY NEEDS?

A. Southern Company Services, on behalf of Georgia Power, performs long-term resource planning studies for the Southern Company System to identify the optimal mix of resources that satisfy the System's TRM. However, resources have to be allocated to each operating company, and that is done by considering each operating companies' needs, which requires the derivation of operating company TRMs. Operating Company TRMs differ from the System TRM based on the difference that exists between the hour when the Company's peak load occurs, and when the System's peak load occurs. This is reflected as diversity factor in calculating TRMs.

Q. BASED ON STAFF'S RECOMMENDED 24.50% SYSTEM TRM, WHAT DOES STAFF RECOMMEND BE USED FOR GEORGIA POWER'S TRM?

A. For purposes of this updated IRP, Staff used the same approach Georgia Power used to translate the System TRM into Georgia Power's TRM. This approach considers historic peak load data to derive diversity factors between the System peak load and each operating company's peak load. Based on Staff's System TRM of 24.50%, Staff determined Georgia Power TRM should be 23.52%. The following table compares the Company's derivation of its System and Georgia Power TRMs to the values Staff derived after correcting the Company's SERVM modeling error.

Table 3: 2022 IRP Target Reserve Margin

	GPC Assumptions (%)	Staff Assumptions (%)
Southern System TRM	26.00	24.50
Georgia Power TRM	25.00	23.52

Staff points out that the Company normally derives peak load diversity factors using historical load data.[17] However, on a forward looking basis, historical trends may no longer continue, given that the Company's new load growth projection may outpace the load growth other Operating Companies experience, and may result in peak load diversity being reduced between Georgia Power and the System. This dynamic should be evaluated further by the Company in the 2025 IRP.

Q. HAS STAFF IDENTIFIED ANY OTHER ADJUSTMENTS IT RECOMMENDS BE USED IN THIS IRP TO THE COMPANY'S STARTING POSITION?

A. Yes. Table A of Exhibit STF-NHW-4 contains Staff's load and resource balance table before any additional new resources are added, and Staff includes two additional items that were not included in the Company's load and resource balance table. Staff's table accounts for capacity uprates associated with the in-progress Hydro Modernization

[17] See STF-JKA-6-1 and STF-JKA-7-4

projects (31 MW starting in 2027),[18] and includes the Mossy Branch battery energy storage resource beginning in the second quarter of 2024, when it comes online (62 MW in 2025-2026).[19] As Mossy Branch was proposed as a demonstration project, the Company did not consider Mossy Branch to be a firm resource in its load and resource balance table on its In-Service date, and instead assumed it would become a firm resource beginning the winter of 2027/2028. Staff disagrees and believes the Company should allow it to provide "real-world operating experience,"[20] and use it to serve load during peak load conditions once it is online this summer, and therefore Staff included it in its load and resource balance table beginning in the second quarter of 2024.

Q. IN DERIVING STAFF'S PROPOSED PLAN, DID STAFF CONSIDER THE INCLUSION OF ANY OTHER RESOURCES THAN THOSE THAT THE COMPANY CONSIDERED IN THIS PROCEEDING?

A. Yes. In addition to the resources the Company evaluated, Staff also considered the possibility of extending the Gaston and Scherer 3 units, which the Company is currently planning to retire by the end of 2028.[21] Staff also accounted for the Company's approved RFPs for renewable and energy storage resources. Additionally, though no capacity value

[18] See STF-PIA Set 6 responses. The Hydro Modernization project investments were approved in both the 2019 and 2022 IRPs.
[19] Company response to JKA 5-5.
[20] Direct Testimony of Jeffrey Grubb, Narin Smith, Michael Bush, and Jeffrey Weathers, Docket No. 42310, March 14, 2019, p. 52, l. 23.
[21] STF-JKA 2-8

has been assigned, Staff's case also provides a placeholder for additional demand response capacity that could help serve some of the additional load, as plans for those resources are evolving. Staff developed its Proposed Plan based on these resource considerations, which appears in Table B of Exhibit NHW-4.

Q. DOES THE USE OF STAFF'S ASSUMPTIONS NEGATE GEORGIA POWER'S NEED FOR NEW CAPACITY RESOURCES?

A. No. Table 4 compares the 2026-2029 capacity shortfall based on the Staff and Company load forecasts at assumed TRM levels. The table also shows the impact on the additional capacity need, assuming Staff's load forecast and TRM, with the addition of the MPC and Santa Rosa PPA's. With Staff's load forecast and TRM assumption, and the inclusion of MPC and Santa Rosa, Georgia Power's next need for capacity is pushed out to 2029. Additional load and resource balance details for the period of 2024 – 2035 are provided in Exhibit NHW-4. It is important to realize, even using the Company's TRM, not Staff's TRM, but still using Staff's load forecast and proposal to acquire MPC and Santa Rosa, the Company's next need for capacity remains pushed out to 2029.

Table 4: Georgia Power Additional Capacity Resource Need (MW)

Cases	2026	2027	2028	2029
Georgia Power - P95 Load Forecast, 26% TRM (GPC assumptions)	175	1,875	2,601	4,807
Staff - P95 Load Forecast + Uniform with Delays, 24.5% TRM (Staff assumptions)		143	793	2,911
Staff Proposed Plan: P95 Load Forecast + Uniform with Delays, 24.5% TRM, addition of MPC and Santa Rosa PPAs [22]				1,173

Request for Proposals (RFP)

Q. DOES STAFF AGREE THAT THE COMPANY NEEDS TO DEVELOP NEW RESOURCES BY THE WINTER OF 2026/2027?

A. Staff agrees the Company will experience significant load growth but disagrees on how quickly all of the resources will be needed. With the addition of the MPC and Santa Rosa PPAs, the Company will not need additional capacity until 2029. This should provide the Company with enough time to conduct an RFP process to obtain resources at prices competitive with the market.

Q. DOES THE COMPANY HAVE TIME TO COMPLETE AN RFP?

A. Yes, the Company could accelerate the RFPs that were approved in the 2022 IRP and allow bidders to offer earlier commencement dates that could satisfy near-term needs.

[22] Staff's Plan, discussed below, also includes Solar and BESS RFP acquisitions, and extends Scherer and Gaston beginning in 2029, which reduces, but does not eliminate, the Company's 2029 capacity need.

This includes the Company's 2029-2031 All-Source RFP and the 500 MW ESS RFP. Staff is disappointed that the Company has not yet issued these RFPs, despite having had ample opportunity and time already to do so. Staff believes the Company could accelerate these RFPs now such that resources could be acquired to meet the Company's needs for new additional resources.

Q. HOW QUICKLY DOES STAFF BELIEVE THE COMPANY COULD CONDUCT AN RFP?

A. Table 5 compares the dates of recent RFPs other utilities have or are conducting (lines 1-6) to proposed schedules from Georgia Power and Staff. (lines 7-10). The other utilities include Santee Cooper,[23] 1803,[24] Kentucky Power Company,[25] AES Indiana,[26] and Entergy Louisiana.[27]

[23] Santee Cooper https://rfpmarketplace.teainc.org/projects/bidder-rfp-view/173,
[24] 1803 https://www.acespower.com/1803ltrfp2019/ and https://www.acespower.com/1803ltrfp2023/
[25] Kentucky Power https://www.kentuckypower.com/business/b2b/energy-rfps/2023-all-source-rfp
[26] AES https://www.aesindiana.com/project-schedule,
[27] Entergy https://spofossil.entergy.com/ENTRFP/SEND/2022ELLRenewablesRFP/Documents/Main%20Body%20-%20Final%20RFP.pdf

Table 5: Comparison of RFP Schedules

	Company	Proposals Due	Delivery Period	Bid Type	Months
1	**Santee Cooper RFP**	3/26/2023	1/1/2024	Market	10
2	**1803 Electric Cooperative**	11/9/2023	1/1/2025	Market	14
3	**Kentucky Power 2023 All-Source RFP**	11/8/2023	5/1/2026	Thermal	30
4			1/1/2027	Storage	38
5	**AES Indiana All-Source RFP**	6/30/2023	6/1/2025	Market	24
6	**2022 ELL Renewables RFP**	8/12/2022	9/30/2025	Market	38
7	**GPC Proposed All Source (6/27/2023)**	[redacted]	[redacted]	[redacted]	[redacted]
8	**Staff Proposed (8/22/2023)**	[redacted]	[redacted]	[redacted]	[redacted]
9	**GPC Proposed All Source (9/12/2023)**	[redacted]	[redacted]	[redacted]	[redacted]
10	**GPC Proposed All Source (Posted)**[28]	6/14/2024	1/1/2029	Market	55

Based on this table, Staff believes the earliest date resources could commence is between 20 and 36 months after bids are due back and evaluation of bids begins. Georgia Power currently has published a schedule for the 2029-2031 All-Source RFP (line 10 above), which indicates that bids are due back on June 14, 2024. Staff believes resources could commence delivery as early as 20 to 36 months later, which would lead to additional resources being available anywhere from the end of January 2026 to the end of May 2027, which is well ahead of a 2029 capacity need.

Another RFP that should be accelerated is the 500 MW RFP for BESS resources, which was approved in the Commission's 2022 IRP Order. The Company has likewise

[28] https://gpc2029-2031all-sourcerfp.accionpower.com/_gpc_2301/calendar.asp

failed to issue that RFP to date, but Staff expects that it will be issued in 2024. Staff witness Kaduk discusses the status of Company's 2023 CARES RFP in his testimony.

IV. GEORGIA POWER'S ECONOMIC STUDIES

Company Studies

Q. WHAT STUDIES DID THE COMPANY PERFORM IN THE 2023 IRP UPDATE?

A. As discussed above, the Company performed the Economic Analysis Study to support its proposed near-term resource acquisitions, and the Resource Mix study to develop an optimal long-term resource plan, considering different uncertainties, including fuel and CO_2.

Q. WHAT OTHER FILINGS IN THIS DOCKET HAS THE COMPANY MADE SINCE THE INITIAL 2023 IRP UPDATE FILING WAS MADE ON OCTOBER 27, 2023?

A. The Company has made a number of supplemental filings since October 27, 2023 to provide additional information supporting its requests, which has challenged Staff's ability to meet a filing deadline of February 15, 2024, including the following:

- 10/27/23 - Initial Filing, Resource Mix Study consisted of the MG0 case only.
- 12/04/23 – Supplemental Filing – Additional Resource Mix Study fuel scenarios provided, and RFI Information shared.
- 12/07/23 – Errata Filing to correct errors in the allocation of new System resources to Georgia Power.
- 01/11/24 – Demand Response Tariffs provided (DCL-1, DCO-1, and CL-1).

- 01/12/24 – Yates CT updated economic analysis reflecting increased costs and additional deliverability information.
- 01/19/24 – Transmission Supplemental Filing to confirm the Santa Rosa and Mississippi Power PPA require no transmission projects and Yates will remain limited to 600 MW until $59.9 million in transmission improvements can be completed.[29]
- 01/31/24 – Certification request for expedited consideration of 1,300 MW of new CT resources to be added at Plant Yates.

Given the 30-day turn-around requirement for discovery, Staff's review of the latest information that the Company has filed has been limited. The timing of the late filed information suggests caution is in order. Staff's proposal provides additional time for these projects to be evaluated. The fact that the Staff has only had two weeks to review the Engineering, Procurement, and Construction ("EPC") contract, with no opportunity to conduct discovery, is further evidence the Yates Certification should be denied.

Economic Analysis Study

Q. WHAT ANALYSIS WAS USED TO ASSESS THE RESOURCES THAT THE COMPANY PROPOSED?

A. The Company's Economic Analysis Study was performed to evaluate the following resources that the Company determined could be acquired quickly to meet the Company's assumed 2026 and 2027 need dates for resources.

[29] Previously Georgia Power assumed the Yates transmission investment would be $79.2 million. The reduction in cost was not accounted for in the Company's updated Yates economic analysis that was filed 1/12/24.

Table 6: Proposed Supply-Side Resources

Resource	Commercial Operation Date ("COD")	Term or Life	Nameplate MW	Winter Equivalence MW
Robins BESS	11/1/2026	20	128	115
Moody BESS	11/1/2026	20	49.5	44.5
MPC PPA	1/1/2024	5	750	750
Santa Rosa PPA	1/1/2024	5	230	230
Yates 8-10 CTs	12/1/2026 [30]	45	1,300	1,070
Co-located BESS + Solar	11/1/2026	20	200	200 [31]

Q. PLEASE DISCUSS GEORGIA POWER'S ECONOMIC ANALYSIS STUDY THAT WAS FILED IN SUPPORT OF THESE RESOURCES.

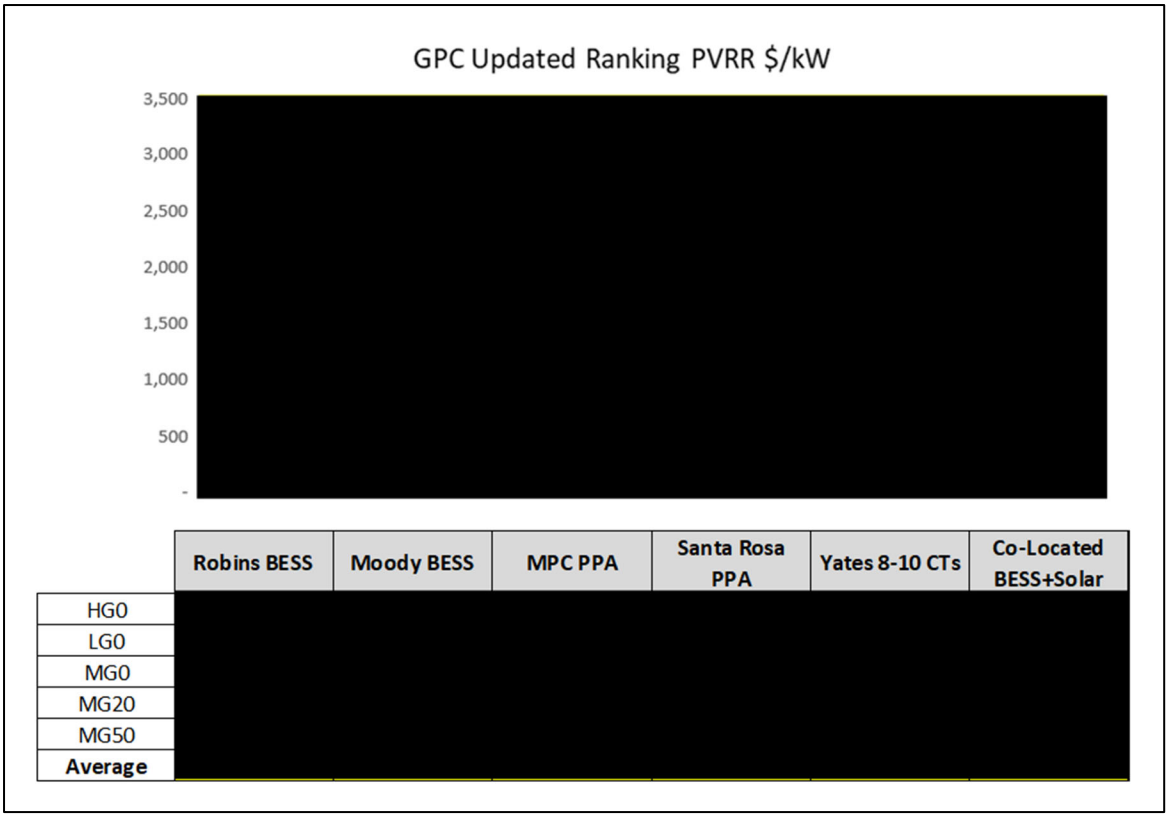
A. Georgia Power's analysis is an Incremental Revenue Requirements ("IRR") analysis. This study compares the annual revenue requirements for the period 2024-2072 for each of the resources under consideration, including the fixed and variable costs net of energy and any other benefits the project may produce. Energy benefits are based on an Aurora run with the evaluation unit operating through the study period. The present value of revenue requirements ("PVRR"), stated on a $/kW basis for each resource, was computed in the analysis. This metric is useful for normalizing the results to compare and rank

[30] Yates 8 providing 357 MW available 12/1/2026 and Yates 9, 10 providing 714 MW in-service 5/1 2027 and 8/1/2027 respectively ahead of the January 2028 Peak. See file: "TS SAM ('23) - 7.0.1 Yates CT 012324 Certification.xlsm," provided in Supplemental Filing January 31, 2024. There is also a limitation of 600 MW at Yates 8-10 until transmission upgrades completed (Summer of 2028).

[31] The Company has assumed a 100% ELCC credit for the co-located projects Solar + BESS projects, which appears inconsistent with the 90% attributed to the new BESS (including Moody and Robins) and 0% attributed to new solar in the mix study.

resources of different sizes and technology choices. Results were provided for each fuel and CO_2 case that the Company modeled. The graph below shows the results of the Company's study based on the Company's fuel and CO_2 cases.[32]

Figure 1: Summary of Georgia Power's Economic Analysis Study Results



[32] The Graph is consistent with the Company's supplemental transmission filing results from January 19, 2024 and certification filing January 31st. The Company failed to supply an analysis using the updated transmission (January 19th) or updated capital costs (Certification Filing on January 31st) and as such the results here reflects staff's adjustment.

In the table above, the five natural gas and CO_2 combinations (LG0, MG0, HG0, MG20, MG50) are included, as well as the average value.

Q. DOES STAFF ENDORSE THE COMPANY'S ECONOMIC ANALYSIS STUDY?

A. No. The study design has shortcomings which limit its usefulness and there are several problems in the execution of the study. At best the study could be useful for choosing between the candidate resources if the Commission determines some of the capacity is not needed. However, the universe of capacity options is limited to these six resources and there is no determination of whether lower cost options exist or even the best mix of the proposed resources.

Q. ARE THERE OTHER CONCERNS REGARDING THE COMPANY'S MODELING APPROACH?

A. Yes. Staff has four other concerns, which relate to dispatch methodology, term equalization, the fact the Company's methodology does not address capacity need issues, and the natural gas and CO_2 emission price forecasts the Company used. Based on these concerns, Staff performed its own economic analysis of the proposed resources, which will be discussed further below in this testimony.

Q. PLEASE EXPLAIN STAFF'S CONCERN REGARDING THE DISPATCH METHODOLOGY USED IN THE ECONOMIC ANALYSIS STUDY.

A. Staff is concerned the Company studied the proposed resources in the Economic Analysis Study using a simplified avoided cost curve dispatch approach instead of using a

production cost load dispatch approach. The Company's approach did use a production cost dispatch (Aurora), initially, for the purpose of deriving a fixed $/MWh market price curve. However, the market price curve was then fixed and used to dispatch each individual proposed resource the Company is considering to acquire. Since the price curve was fixed before the target resources were considered, and no dynamic impacts were evaluated,[33] the Company's dispatch approach ignored factors such as operating constraints, possible resource curtailments, and the value of resources as resource availability changes. The Company also relied on outdated natural gas and CO_2 price forecasts in its study.

Staff is concerned that the avoided cost methodology is a less accurate way of representing dispatch dynamics and recommends that the conventional load based dispatch approach be used instead. Staff used this alternative approach in its independent analysis discussed below.

Q. PLEASE EXPLAIN STAFF'S CONCERN REGARDING THE TERM EQUALIZATION ASSUMPTIONS USED IN THE ECONOMIC ANALYSIS STUDY.

[33] Once an avoided cost curve is derived, it is considered fixed because the avoided cost curve does not update as resources are added or removed from the evaluation. In comparison, these dynamic impacts are accounted for when a production cost approach is performed, because resources are dispatched against load and adjust as other resources are added or removed from the evaluation.

A. The Company uses a "Term Equalization" adjustment to address the problem of evaluating resources having different lives, which otherwise would not be considered in the $/kW metric evaluation. The candidate resources are all assumed to be replaced at the end of their contract term or useful life with combustion turbines that have the same capital and operating costs as the Yates Units 8, 9 and 10 Units.

Q. IS THIS THE MOST ACCURATE APPROACH TO EVALUATE RESOURCES THAT HAVE DIFFERENT LIVES?

A. No, a better approach, if this method were to be used, would be to assume the mix of resources should remain constant replacing retiring resources with like capacity (thermal with thermal, storage for storage, solar for solar, combined cycle with combined cycle, etc.), rather than assuming all replacement capacity would be combustion turbine units. However, Staff proposes a different methodology entirely, which relies on an optimization approach, in which resources are optimally selected when resources retire.

Q. PLEASE EXPLAIN STAFF'S CONCERN REGARDING THE STUDY'S CONSIDERATION OF NEED DATE IN THE ECONOMIC ANALYSIS STUDY.

A. The Company's Economic Analysis Study fails to realistically consider resource capacity need issues. The problem is the Company's evaluation only compares a Net Present Value ("NPV") $/kW metric for each resource and does not consider the impact of the Company having excess capacity. For example, a completely unnecessary, but otherwise low-cost resource, could have a low NPV $/kW value leading to the conclusion that the

resource should be acquired irrespective of whether it is needed. An optimal resource expansion planning model, such as Aurora, considers both cost issues and capacity need issues in identifying the most economic combination of resources.

Q. PLEASE EXPLAIN STAFF'S CONCERN REGARDING THE STUDY'S USE OF OUTDATED COMMODITY PRICE ASSUMPTIONS IN THE ECONOMIC ANALYSIS STUDY?

A. The Company has prepared its Economic Analysis Study using outdated fuel and carbon tax forecasts. The Company stated:

> *For its long-term fuel price forecasts (natural gas, coal and oil), the Company uses projections provided by the United States Energy Information Administration in its Annual Energy Outlook ("AEO"). For the economic analysis supporting the 2023 IRP Update, the Company used fuel price forecasts from AEO 2022 and for the Resource Mix Study supporting the 2023 IRP Update, the Company used fuel price forecasts from AEO 2023.*[34]

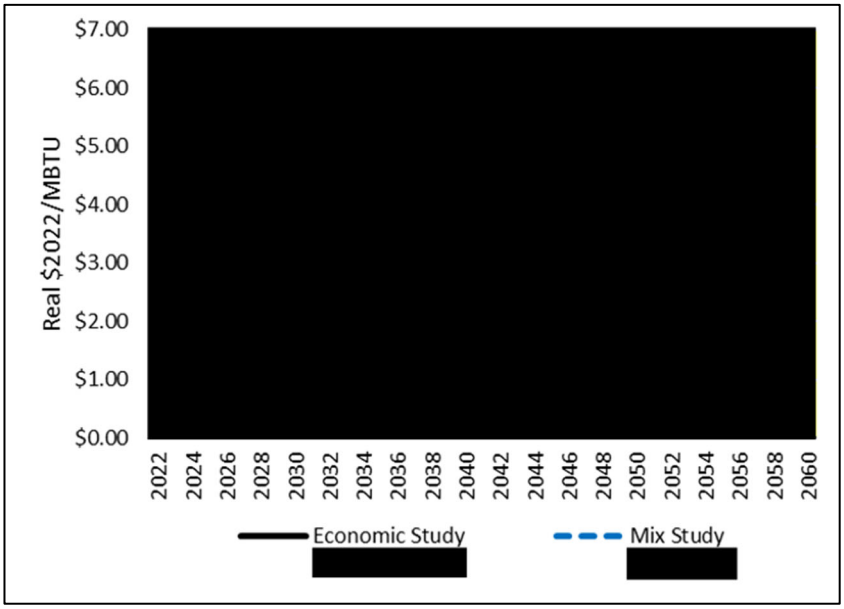
Q. IS THERE A DIFFERENCE BETWEEN THE 2022 AND 2023 AEO FUEL FORECASTS?

A. Yes, the largest differences occur in the early years of the forecasts (2026-2034). The 2022 AEO forecast, used in the Economic Analysis Study, reflects the sudden spike in Natural Gas prices and general inflation that occurred concurrent with preparation of the AEO 2022 report. The 2023 forecast, used in the Resource Mix Study, was prepared

[34] STF-JKA-2-12

more recently and reflects the much lower prices currently prevailing. By 2027 the forecasts are essentially the same, though eventually the 2023 forecast predicts lower gas prices. The figure below illustrates that the natural gas price forecast used in the Economic Analysis Study considered gas resources to be much more expensive to run compared to what they cost to run in the forecast used in the Resource Mix study for the period 2028 to 2038. Further out in time, the two forecasts essentially converge.

Figure 2: Natural Gas Price Forecast Comparison
(Mix Study vs. Economic Analysis)



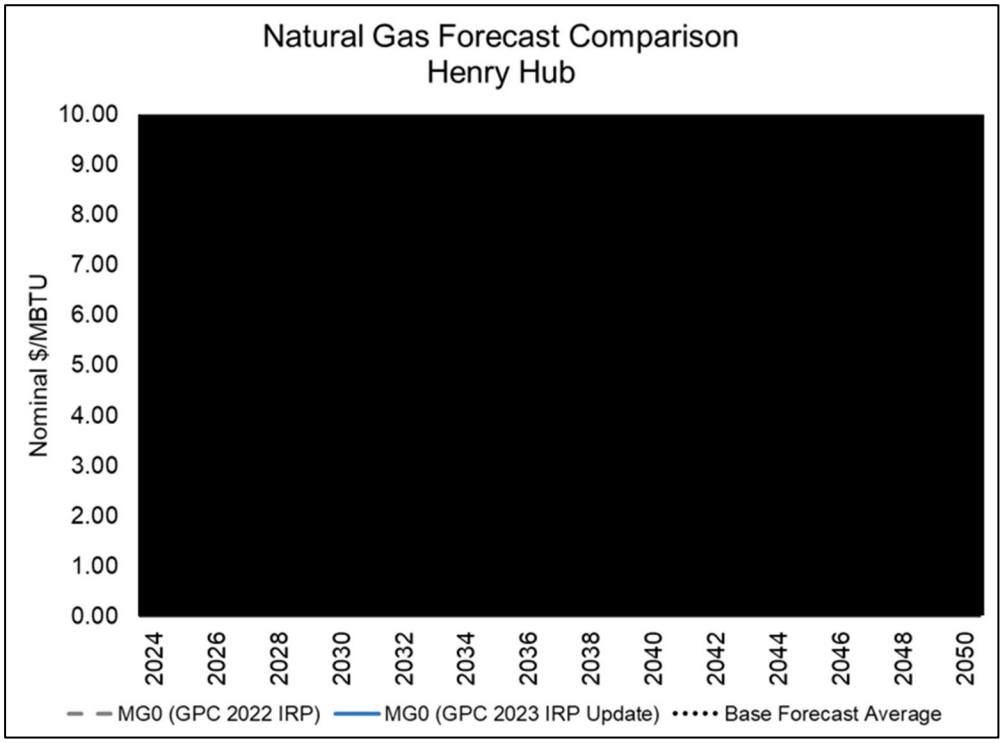
Q. HOW DO THE COMPANY'S GAS PRICE FORECASTS COMPARE TO OTHER PUBLICLY AVAILABLE FORECASTS?

A. The following figure compares the Company's forecasts to a range of other publicly available forecasts, as noted in gray shading,[35] and indicates the Company's forecast is reasonable and within the band consisting of the other publicly available forecasts. In the 2022 Georgia Power IRP natural gas forecast, the Company "adopted and adapted paths produced by the U.S. Energy Information Administration ("EIA") for its 2021 Annual Energy Outlook ("AEO")."[36] The Company also used AEO forecasts for the 2023 IRP Update. In the 2023 IRP Update, for the Economic Analysis, the Company used fuel price forecasts from AEO 2022, and for the Resource Mix Study, the Company used fuel price forecasts from AEO 2023.

[35] Dominion Energy South Carolina 2023 IRP - https://www.dominionenergy.com/-/media/pdfs/global/company/desc-2023-integratedresource-plan.pdf, pg. 49.
GPC 2022 IRP - https://psc.ga.gov/search/facts-document/?documentId=188519, Main Document, pg. 7-38.
EIA AEO2023 - https://www.eia.gov/outlooks/aeo/
Entergy Louisiana 2023 IRP - https://cdn.entergy-louisiana.com/userfiles/content/irp/2023/Combined-Final-Report-05-22-23.pdf, p. 76.
PacifiCorp 2023 - www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integratedresource-plan/2023-irp/PacifiCorp_2023_IRP_PIM_Feb-23-2023, pdf, p. 22.
Santee Cooper 2023 IRP, https://www.santeecooper.com/About/Integrated-Resource-Plan/Reports-and-Materials/Santee-Cooper-2023-Integrated-Resource-Plan_Final-Rev_01.pdf, p. 92.
Duke Energy Carolinas 2023 IRP www.duke-energy.com/-/media/pdfs/our-company/carolinas-resource-plan/appendix-c-quantitative-analysis.pdf, Appendix C, p. 44.

[36] 2022 IRP Main Document, p. 7-35.

Figure 3: Natural Gas Price Comparison
(2022 IRP vs. 2023 IRP Update)



Q. DO THE CARBON TAX FORECASTS THE COMPANY USED DIFFER BETWEEN THE ECONOMIC ANALYSIS AND THE RESOURCE MIX STUDIES?

A. Yes. In both studies two carbon tax forecasts are modeled, a $20/Ton and a $50/Ton forecast, and they escalate at approximately the same rate.[37] However, the Economic

[37] STF-JKA-2-12 PD

Analysis Study assumes carbon taxes will be in effect beginning in 2025, while the Resource Mix Study assumes carbon taxes will be in effect in 2030, a delay of five years.[38] It is unreasonable to assume in the Economic Analysis Study that carbon taxes would go into effect next year, given there is no pending legislation, and little expectation that legislation will be enacted soon. Even if legislation were enacted soon, typically, this type of legislation would not require an immediate start of the legislation's requirements. It could allow five or more years before the law would begin. Therefore, Staff finds that the Company's Resource Mix Study relied on a more reasonable start date assumption than the CO_2 start date assumption used in the Economic Analysis Study.

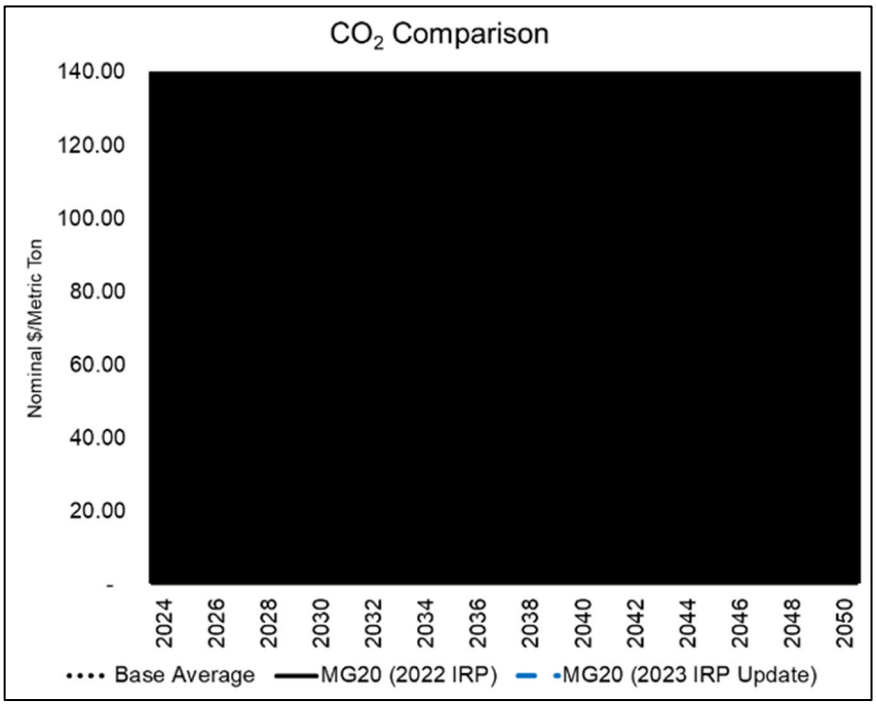
Q. HOW DO THE COMPANY'S CO_2 FORECASTS COMPARE TO OTHER PUBLICLY AVAILABLE CO2 FORECASTS?

A. The following figure compares the Company's Resource Mix Study CO_2 forecast from the 2022 IRP to the Company's Resource Mix Study CO_2 forecast from this IRP, and to a range of other publicly available CO_2 forecasts (in gray shading). The Company's prior forecast appears to be out of date when compared to other publicly available forecasts,

[38] *id* Attachment H, public disclosure.

but the forecast the Company used in the 2023 IRP Update Resource Mix Study appears to be reasonable when compared to other publicly available forecasts.[39]

Figure 4: CO_2 Emissions Price Forecast Comparison (2022 IRP vs. 2023 IRP Update)



[39] Dominion Energy South Carolina 2023 IRP - https://www.dominionenergy.com/-/media/pdfs/global/company/desc-2023-integratedresource-plan.pdf, p. 49.
GPC 2022 IRP - https://psc.ga.gov/search/facts-document/?documentId=188519, Main Document, pp. 7-38.
AVISTA 2023 IRP https://www.myavista.com/-/media/myavista/content-documents/about-us/our-company/irp-documents/2023-avista-wa-electric-irp-progress-report.pdf pg. 154
Entergy Louisiana 2023 IRP - https://cdn.entergy-louisiana.com/userfiles/content/irp/2023/Combined-Final-Report-05-22-23.pdf, p. 76.
PacifiCorp 2023 IRP - https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integratedresource-plan/2023-irp/PacifiCorp_2023_IRP_PIM_Feb-23-2023, pdf, p.22
Santee Cooper 2023 IRP, https://www.santeecooper.com/About/Integrated-Resource-Plan/Reports-and-Materials/Santee-Cooper-2023-Integrated-Resource-Plan_Final-Rev_01.pdf, p. 92.

Q. WHAT IS STAFF'S POSITION CONCERNING THESE FORECASTS?

A. Staff believes the most up to date fuel and CO_2 forecasts should be used for analyses that utilities conduct. In the case of the CO_2 forecast, it is unreasonable to use a forecast that assumes carbon taxes will go into effect in one year's time. Staff believes the Resource Mix Study assumptions are more realistic to rely on for both natural gas and CO_2 price forecasts.

Request for Information (RFI)

Q. DID THE COMPANY CONSIDER ALL POTENTIAL RESOURCE OPTIONS BEFORE DEVELOPING ITS PLAN TO MEET SHORT-TERM NEEDS?

A. No. The Company had already begun developing projects months ahead of issuing its RFI that was intended to determine if other potential resources could be acquired, and the Company could have issued its RFI well before it did. Ultimately, the Company did not include any potential projects that were identified in its Request for Information ("RFI") process in its economic analysis. The RFI process was initiated in September 2023,[40] and the results were filed in the docket on December 4, 2023, in a Supplemental filing to this IRP, referred to as the "RFI for Capacity Resources – Summary of Results." The Company assumed that these projects would not be available in time to meet the 2027/2028 winter peak, noting:

[40] RFI Summary, December 4, 2023, p. 1.

> As demonstrated by the Company's RFI Summary Report included in Georgia Power's Supplemental Filing made December 4, 2023, there is no indication from the market that there are additional existing resources that can meet the Company's capacity needs in the winter 2025/2026 to winter 2027/2028 timeframe. The RFI results support the Company's resource plan identified in the 2023 IRP Update.

It appears that the Company relied on the RFI to conclude that there were no other resources that it needed to consider; however, the RFI is an incomplete picture of what could be available from the market. Without conducting an RFP, the Company would not be able to know, through the RFI, what other projects, at the same level of development, were or are available.

It also appears the Company only used the RFI to justify its self-build resource options. In fact, the RFI survey was initiated *only after* the Company began negotiations or analysis concerning its proposed capacity resources, which the Company began on the following schedule:[41]

- Co-located Solar/BESS – April 2023
- MPC – July 2023
- Santa Rosa – July 2023
- Moody and Robins – July 2023
- Yates – July 2023.

[41] STF-JKA-2-19 h.

Furthermore, the Company has provided details of other potential projects where a party has a solar PPA with the Company already and at which the Company could potentially co-locate Company-owned BESS resources at the site. The Company states that it may bring these projects to the Commission for approval in 2024 if negotiations with the developers are successful.[42] Given that there is sufficient time to address the Company's resource needs based on Staff's Plan, the Company's projects should be bid into an RFP to be evaluated against other market opportunities.

Q. DID THE COMPANY RECEIVE INDICATIVE PRICING INFORMATION FROM THE RFI RESPONSES?

A. Yes. Even though the Company indicated "the majority of the respondents didn't provide pricing," there was still some useful pricing information available.[43] The Table below shows a summary of the indicative pricing for a selection of projects with expected near-term in-service dates of ESS type resources.

[42] Response to STF-PIA 9-1 identifies additional BESS co-location opportunities [redacted]

[43] Day 1 transcript page 0215 lines 8-13 "I would not totally agree with that assessment. Plus, I would correct that the RFI was not just for the time period in this 2023 IRP update. It was also for the '29 through '31. And the majority of our prices didn't even get -- the majority of the respondents didn't provide pricing."

Table 7: Selected RFI Response Summary

XML ID #	Type	PPA Term	Resource Type	Capacity MW	Proposed Availability	Project Price (BTA/APA)

Q. COULD ANY OF THE RFI PROJECTS COMMENCE OPERATION BY THE COMPANY'S RESOURCE NEED DATE OF 2029?

A. Yes. Based on the Staff load forecast and recommendations (approval of MPC, Santa Rosa, and an accelerated RFP process) the listed projects could be available to meet the 2028/2029 winter peak.

Q. WERE ANY OF THE RFI RESPONSES MORE ECONOMIC THAN THE COMPANY'S PROPOSED PROJECTS?

A. Yes. The table above indicates there may be more economic BESS projects that could be supplied by developers in the market. Staff acknowledges that the RFI responses would

still require additional investigation, contractually obligated bids, and possible transmission costs, but there were RFI responses that appear to be more economic than the Company's proposed resource acquisitions.[44] For example, the RFI indicates developers may be able to develop larger projects, such as 200 MW installations of 4 hour BESS projects for approximately [redacted][45] This can be compared to the Company's proposed Moody (49.5 MW), Robins (128 MW), and Co-located [redacted] (200 MW) BESS projects that are approximately [redacted] respectively, which translate to approximately [redacted] on a $/kW basis.

Furthermore, the Company's Resource Mix Study provides a view of "generic candidate unit" project costs which can be considered a proxy for market-based resources. The source of the generic candidate unit cost information is the detailed Technology Application Standards ("TAS") reference document that Southern Company maintains and updates on behalf of all operating companies, and contains generation technology input assumptions for all resource types that Southern Company monitors in the market. Southern Company updates the information based on its interaction with

[44] In response to STF-JKA-6-6, the Company states it did not evaluate the RFI pricing provided, "the Request for Information ("RFI") conducted was not a Request for Proposals and therefore the submissions were not bids, pricing was not required or provided by all respondents, and no economic or transmission evaluation was performed for the responses provided in the RFI."

[45] [redacted] as provided in the December 4, 2023 Supplemental filing TS Workpapers associated with the Request for Information.

market players and uses this information in studies it performs. Essentially, the costs in the TAS represent the best estimate of what Southern Company believes resources can be constructed for based on market information. The TAS indicates that Southern Company has determined that BESS resources could be constructed for a cost of [redacted], which is again less than the costs of the Company's proposed projects on a $/kW basis.[46]

Finally, in this proceeding, the Company has primarily focused on co-locating BESS resources at solar sites, and while there may be benefits of doing this, there may be other potential sites that batteries could be located that could provide even greater benefits to customers and should be considered.[47]

Revenue Considerations ("Downward Pressure on Rates")

Q. GEORGIA POWER HAS ASSERTED SERVING NEW LARGE CUSTOMER LOADS WOULD PUT "DOWNWARD PRESSURE" ON RATES.[48] IS THAT AN ACCURATE STATEMENT?

A. It may not be accurate for all customers or customer classes. The Company provided a calculation to support its assertion that indicates the revenues from new large customer loads exceed the costs incurred to serve these customers, which would put downward

[46] "TS SAM ('23) - 7.0.1 - BESS 4hr.xlsm" $[redacted] for 300 MW of winter capacity equivalence credit in-service in 2029.
[47] Co-located solar is limited in its summer peak dispatch contribution and there may be additional ITC value captured in other projects.
[48] Testimony of Georgia Power Company, Docket No. 55378, p. 10 and Day 1 Hearing Transcript pp. 0116, 0118, 0122, 0124, 0135-136, 160 and others.

pressure on rates.[49] This calculation is performed at a Company level as though there was only a single customer or customer class and then assumed to apply to residential customers, which may be misleading. However, rates are not set at the Company level but are developed specifically for individual customer classes, and this must be considered when calculating the impact of new large customer loads on the bills and rates of all individual customer classes.

Q. IS THE COMPANY'S CALCULATION THAT SHOWS DOWNWARD PRESSURE ON RATES COMPLETE AND COMPREHENSIVE?

A. No. The analysis only covers three years and should be extended to ten years. There are additional costs such as transmission investment and O&M expenses necessary to serve new large customer loads that should be taken into account in the analysis. Also, the Company's calculation fails to account for increased fuel costs, which may be a significant cost. The calculation also appears to implicitly assume some of the revenue collected from new large customer loads is diverted to the residential customer class. That is not consistent with how rates are developed in a Cost of Service Study.

Q. HOW ARE RATES DEVELOPED FOR INDIVIDUAL CUSTOMER CLASSES?

A. Through a Cost of Service Study that is generally filed by the Company in base rate cases. In a Cost of Service Study, Georgia Power's costs (revenue requirement) are

[49] STF-DEA-3-6 Supplemental Attachment A

allocated across all customer classes and then rates for each customer class are set to collect enough revenue to cover those costs.

Q. COULD SOME CUSTOMER CLASSES HAVE DOWNWARD PRESSURE ON RATES WHILE OTHER CUSTOMER CLASSES HAVE UPWARD PRESSURE ON RATES AS A RESULT OF SERVING NEW LARGE CUSTOMER LOADS?

A. Yes. This depends on how the Company's costs are allocated to individual customer classes in a Cost of Service Study. In the Company's Cost of Service Studies, Company-wide costs are spread to all customer classes. If this same allocation methodology were applied including the new large customer loads and associated costs, then the potential exists that the other customer classes such as residential and small business classes would incur higher costs and upward pressure on rates.

Q. COULD BETTER INFORMATION BE PRODUCED TO ANSWER THE QUESTION CONCERNING "DOWNWARD PRESSURE ON RATES," WHICH COULD BE USED TO MITIGATE THE IMPACT OF SERVING NEW LARGE CUSTOMER LOADS ON RESIDENTIAL AND SMALL BUSINESS CUSTOMERS?

A. Yes, an analysis that addresses the flaws mentioned above could be performed in order to determine whether or not downward pressure on rates will occur for all customer classes. Ultimately the Commission could use this information in the 2025 base rate case to adjust

the Company's Cost of Service Study to mitigate the impact of serving new large customer loads on other customer classes.

Q. WHAT IS STAFF'S RECOMMENDATION TO ADDRESS THIS ISSUE IN THIS IRP?

A. First, given the level of interest in this proceeding in knowing whether serving the new large customer loads will put "downward pressure on rates," the Company should file in rebuttal testimony, a Cost of Service Study that allocates the new costs associated with the Company's proposed resources and the new loads to customer classes based on allocation methodologies consistent with the Company's most recent Cost-of Service Study. By the Company performing this study with the corrections Staff outlined above, the Commission will be able to see impacts with and without the new large customer loads, and will be able to determine clearly how the new large customer loads will impact the individual customer classes.

Second, Staff recommends that when the Company files its next IRP in January 2025, the Company should be required to file an updated Cost of Service Study as outlined above, which should also be consistent with the latest data known at the time of that filing. Filing this information in the 2025 IRP would give Staff time to do a thorough review of the Company's Cost of Service Study and develop its own Cost of Service Study, if necessary, ahead of the next rate case.

Q. WHAT IS STAFF'S CONCLUSION?

A. Staff does not believe the Company has conducted an adequate study to address the question of whether or not the new load will provide upward or downward pressure on rates for all customers. That question has been of paramount interest in this proceeding, and Staff recommends that GPC provide a revised Cost of Service Study in rebuttal testimony and in the next IRP that considers all appropriate costs associated with the new large customer load to determine impacts on each individual customer class.

In addition, because Staff is concerned that individual customer class rates could be impacted as a result of adding significant new customer loads, it is even more critical that the Company be required to identify the least-cost resources to serve that load. Staff continues to recommend that this be ensured by the Company selecting resources through RFP processes.

V. STAFF ANALYSES

Q. HOW DID STAFF ADDRESS ITS CONCERNS WITH THE COMPANY'S ECONOMIC ANALYSIS STUDY?

A. Given the problems inherent in the Company's Economic Analysis Study, Staff decided to perform two analyses using Aurora and modeling data from the Company's Resource Mix Study. The first study was Staff's version of a Resource Mix Study that Staff used to identify which, if any, of the proposed resources should be selected to satisfy short-term needs, and which generic candidate resources should be selected to satisfy long-term needs. The second was a Ranking Analysis that Staff developed to order the Company's

proposed resources from best to worst in the event the Commission prefers that more resources be acquired beyond what Staff recommends. Both of these analyses address the modeling flaws discussed above.

Staff's Resource Mix Study

Q. WHY DID STAFF PERFORM A RESOURCE MIX STUDY?

A. Staff performed its own Resource Mix Study to use Staff's preferred modeling assumptions (primarily load forecast and TRM), to optimally select both short-term and long-term resources, and to address the flaws that Staff identified in the Company's Economic Analysis modeling approach that were discussed above.

Q. PLEASE PROVIDE AN OVERVIEW OF STAFF'S MODELING APPROACH.

A. Staff evaluated the proposed resources, and considered whether all of the proposed resources had to be acquired or whether just some of the proposed resources could be acquired as a bridge, while procurement processes could be performed to acquire other resources more competitively, and potentially save customers money. Staff's analysis traded off the need to add the new proposed resources quickly, against generic candidate units that could be acquired by the 2027/2028 time frame. Staff used the Company's Resource Mix model (Aurora) and data assumptions, such as the generic candidate

resource assumptions.[50] Georgia Power's Resource Mix Study included generic CTs, CCs, BESS and Solar resources.

Staff performed its modeling under base MG0 and sensitivity MG20 scenarios. Staff's study period was 2024 to 2040, which allowed Staff to focus on the near-term impacts of the increased load, and the near-term cost/benefits of the resource selections in 2027, as well as to identify resources for a longer-term period, and to do so with reasonable run times. For purposes of modeling capital costs for the proposed resources in Aurora, Staff computed economic carrying charge ("ECC") cost profiles based on the revenue requirement data that the Company modeled in its Economic Analysis Study.

Q. WHAT ASSUMPTIONS DID STAFF RELY ON FOR NEW RESOURCE OPTIONS?

A. Staff relied on the Company's assumptions for new build resource options as shown below.

[50] The Southern Company developed the generic candidate resource assumptions in the TAS for use in modeling studies such as the Resource Mix Study.

Table 8: Summary of Company Modeled Generic Resources [51]

Resource Name	Short Name	Capacity Equivalence (%)	Build Time (Yr)	Asset Life (Yr) [52]	MG0 Date Available
Combined Cycle	CC	100%	[redacted]	[redacted]	2030
Combined Cycle with Carbon Capture & Sequestration	CCwCCS	100%	[redacted]	[redacted]	2034
Dual Fuel Combustion Turbine with Future Emission Controls	CTwSCR	100%	[redacted]	[redacted]	2027
Reciprocating Internal Combustion Engines	RICE	100%	[redacted]	[redacted]	2029
Solar PV	Solar	0%	[redacted]	[redacted]	2027
Onshore Wind Power	Wind	35% [53]	[redacted]	[redacted]	2032
Battery Energy Storage System (4 hour)	BESS	Declining Tranches	[redacted]	[redacted]	2027
Medium Duration Energy Storage System (12 hour)	MDESS	100%	[redacted]	[redacted]	2034
Nuclear	Nuclear	100%	[redacted]	[redacted]	2035

Staff compared the Company's generic resource cost and operating characteristic assumptions to publicly available data to assess the reasonableness of the Company's assumptions as shown in Exhibit NHW-5. The sources for the publicly available data included the National Renewable Energy Laboratory ("NREL"), Lazard, and information

[51] 2023 IRP Update, Resource Mix Study Report, Table 2: Candidate Technology Assumptions, pg. 14. See also the technology screening analysis information the Company provided in response to STF-JKA-2-16.
[52] CC and CT asset lives have increased from [redacted] assumed in the 2022 IRP.
[53] The ELCC value of Onshore Wind Power resources decreased from 41% assumed in the 2022 IRP.

from a selection of other utilities. Staff also included a comparison to Georgia Power's 2022 IRP assumptions and notes that the Company's assumed build costs have increased, which is consistent with market trends. The Company's latest generic candidate resource cost estimates appear reasonable, though generally they are lower in cost compared to the benchmark datapoints.[54]

Staff also included the Company's proposed BESS, BESS plus Solar resources, Yates, and the proposed Santa Rosa PPA as additional selectable options in the optimization model. Finally, Staff included the possible extension of the Gaston and Scherer units from a planned retirement at the end of 2028 to the end of 2035 as an additional selectable option that Aurora could make.

Q. PLEASE SUMMARIZE THE ASSUMPTIONS STAFF REVISED IN ITS ANALYSIS?

A. The following table compares the input assumptions that Staff used in its analysis compared to what the Company used in its Resource Mix Study:

[54] [redacted]

Table 9: Staff Aurora Study Assumption Summary

Data Assumption	Company Resource Mix Study	Staff Analysis
Study Length	2024-2057	2024-2040
System TRM	26%	24.5%
Load Forecast	Company P95 Forecast	Revised Uniform w/ Delays P95 Forecast
Proposed Resources	Omitted, with exception of MPC PPA in 2027/2028	Selectable in 2026/2027, with presumed acceptance of MPC PPA.[55]
Gaston and Scherer Extensions	Not selectable	Selectable[56]

As discussed above, Staff allowed Aurora to determine whether it would be economic to extend the lives of the Scherer 3 and Gaston 1-4 Units from 2028 to 2035. Staff does not recommend a decision on extending the lives of Scherer 3 and Gaston 1-4 be made in this proceeding, but instead be considered in the 2025 IRP, in the context of a

[55] Staff's proposed resource assumptions included updated B2024 proxy fuel costs for Yates and Santa Rosa (STF-JKA 3-9 and STF-JKA 3-10) as well as the Max ICE Factor to be greater of MG0 and MG20 for utilization in both studies. Staff relied on the MG0 resource availability assumptions with the exception of the CC availability ending in 2034 in Staff's MG20 case as PTC and BESS differences due to the IRA past 2045 are not required for Staff's study that ended in 2040.

[56] Fixed Costs were obtained from STF-JKA 5-1 and STF-JKA 5-2

comprehensive unit retirement study. However, if a decision were ultimately made to extend the lives of these units, the need for additional new capacity resources beginning in 2029 would not be as great as the Company has indicated and could reduce ratepayer cost by delaying the need for additional new capacity.

Finally, in the 2022 IRP, Staff included modeling adjustments for BESS and Solar Effective Load Carrying Capability ("ELCC") values and solar integration costs, and in the modeling it performed in this IRP, the Company appears to have generally adopted Staff's recommendations.[57]

Q. HOW DID STAFF CONDUCT ITS RESOURCE EVALUATION?

A. Staff performed a series of Aurora optimization runs based on the Company's Resource Mix Study (Aurora Study) and database, in which the entirety of the Southern Company System was modeled. Staff evaluated both the MG0 (medium natural gas forecast and zero CO_2 cost) case and the MG20 (medium natural gas forecast and 20 $/ton CO_2 cost) case over Staff's study period. The purpose of Staff's analysis was to allow the proposed resource options (Moody, Robins, Battery plus Storage, Yates) to be modeled as selectable resources. However, in all of the cases Staff ran, the MPC resource was treated

[57] The Company used different ELCC values for BESS resources in its studies. For example, 100% is used for first tranche of new BESS resources, 90% for Robins and Moody at existing solar locations, and 95% for the 500 MW ESS RFP projections. These assumptions may need to be refined in future IRPs for consistency. Also, the Company continues to model a 0% ELCC for Solar in the 2023 IRP modeling. Staff notes that if Solar were given a small capacity contribution value, which may be reasonable, additional solar resources could further defer the near-term need date of capacity. See ELCC study results provided in STF-JKA-2-11.

as having been selected first, based on cost and reliability considerations, and the fact that MPC resources are already operating as a part of the Southern Company System resources.

Q. WHAT WERE THE RESULTS OF STAFF'S EVALUATION?

A. Staff's results showed that only Santa Rosa (and MPC as discussed above) was selected, but none of the other proposed resources (Robins, Moody, BESS plus Solar, Yates) were selected when the proposed resources were modeled as selectable resource options. This occurred in both a case that was based on the Company's load forecast and TRM assumptions, and in a case that was based on Staff's lower load forecast and TRM assumptions.

The following table compares three sets of results that led to the conclusions above, associated with the MG0 case for the period of 2024 to 2030. The load, TRM, and resource options that were assumed in each case are summarized in the first few rows of the table. The label "Resource Options: STF" is intended to indicate that the proposed resources were selectable in that case, and to mean that the extension of Scherer and Gaston was decided by Aurora. The MW values are shown in cases in which the resources were selected by the optimization run for the Southern Company System, and N/A implies that the resources were not considered selectable in the specified run. The amount of MWs shown is assumed to be the cumulative nameplate capacity installed between 2024 and 2030.

Table 10: GPC Resource Mix Study vs. Staff Resource Mix Study
MG0, Case
Southern Company System MWs Selected by 2030

LOAD (MG0)	GPC	GPC	STF
TRM	26%	26%	24.5%
RESOURCE OPTIONS:	GPC	STF	STF
Generic Resource Options (MW*)			
CC	[redacted]		
CT w SCR			
Solar			
BESS (Tranche 1)			
BESS (Tranche 2)			
Proposed Resources			
MPC PPA**	750	750	750
Santa Rosa PPA**	N/A	230	230
Robins BESS	N/A	-	-
Moody BESS	N/A	-	-
200 MW Co-Located Solar	N/A	-	-
Yates 8-10	N/A	-	-
Extension Options			
Scherer	N/A	645	645
Gaston	N/A	1,037	1,020

*Nameplate MW
**MPC and Santa Rosa end in 2028

N/A indicates resource was not included in Aurora as a selectable resource

The leftmost case was run the same way the Company set up the case in its Resource Mix Study, but for Staff's study period of 2024 to 2040. In that case, the Company's load forecast and TRM assumptions were modeled, and the proposed resources were not treated as selectable resources. In that case, MPC was modeled as having been selected, and the results show that a set of generic candidate resources were selected to satisfy Southern Company's load requirements.

In the middle case, Staff reran the Company's Resource Mix Study, but allowed the proposed resources to be selectable. Staff also allowed Aurora to decide if the Scherer and Gaston units should be permitted to continue to operate beyond 2028. The results of the middle case show that MPC and Santa Rosa were selected, along with a selection of generic candidate resources. In that case, the other proposed resources (Yates, Robins, Moody, and the BESS plus Solar options) were found to be more expensive and were not selected in the run. Also, Aurora found that it would be economic to continue to operate the Scherer and Gaston units beyond 2028.

The rightmost case used Staff's load forecast and TRM assumptions, and the results show, again, that only MPC and Santa Rosa were selected, along with a set of candidate generic resources. Fewer candidate generic resources were selected because Staff's case used a lower load forecast and TRM assumption. Once again, Aurora found that it would be economic to continue to operate the Scherer and Gaston units beyond 2028.

The conclusion from these analyses is that MPC and Santa Rosa should be acquired, but beyond that other resources should be determined in an RFP process. In addition, allowing Scherer and Gaston to operate past 2028 could result in the Company needing to add fewer resources in the 2029 to 2035 time period. While this implies it may be lower in cost for Georgia Power to extend the operation of those units, Staff

recommends that this decision be evaluated further in the 2025 IRP based on the Company performing a detailed unit retirement study.

Q. SINCE THE RESOURCE MIX STUDY IDENTIFIES RESOURCES BASED ON THE SOUTHERN COMPANY LOAD REQUIREMENT, HOW ARE RESOURCES ALLOCATED TO GEORGIA POWER?

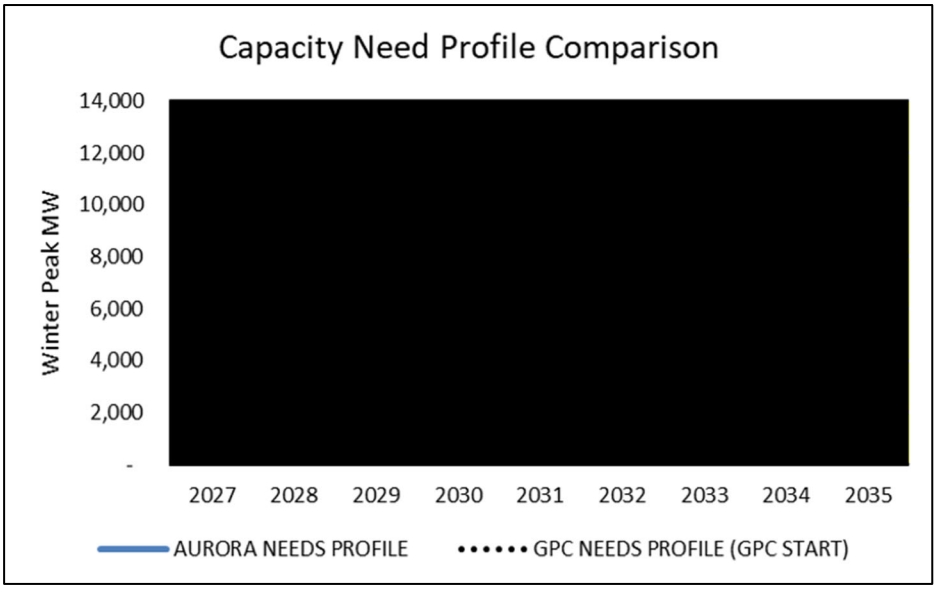
A. After the Resource Mix Study was performed and an expansion plan was derived to satisfy the Southern Company load requirement, a spreadsheet analysis was performed to allocate the resources selected by Aurora to Georgia Power. The spreadsheet determined how much of each resource type should be allocated to Georgia Power to meet its needs on a peak demand and energy basis compared to the other operating companies' needs. The operating companies with the greatest needs were assigned resources first.[58] Based on the Company's allocation process, Georgia Power was assigned a majority of the CT, CC, and BESS Tranche 1 capacity resources before 2030 ([redacted]%, [redacted]%, and [redacted]% respectively).

The following graph indicates the amount of incremental capacity that will be needed to satisfy the System's load requirements, and the amount that was allocated to Georgia Power using the spreadsheet model. It appears that due to Georgia Power's

[58] See the Company's December 7, 2023 Supplemental Errata filing and spreadsheet, "TS Capacity Expansion Plans Supplemental - Errata.xlsx"

significant new large customer load, most of the Southern Company's resource needs will be driven by Georgia Power's needs, and most of the incremental new capacity resources will have to be assigned to Georgia Power.

Figure 5: Incremental System Needs vs. Incremental GPC Needs (MG0)



Q. DID STAFF CONSIDER THE POSSIBILITY OF HOW RESULTS WOULD CHANGE UNDER A HIGHER CARBON COST CASE?

A. Yes, Staff ran a sensitivity case using MG20 assumptions to evaluate if the proposed projects would fair differently under a carbon sensitivity case. For this analysis, the same three cases are presented (Company, Company with Selectable Options, and Staff Case with Selectable Options).

Table 11: GPC Resource Mix Study vs. Staff Resource Mix Study
MG20, Case
Southern Company System MWs Selected by 2030

LOAD (MG20)	GPC	GPC	STF
TRM	26%	26%	24.5%
RESOURCE OPTIONS:	GPC	STF	STF
Generic Resource Options (MW*)			
CC	[redacted]		
CT w SCR			
Solar			
BESS (Tranche 1)			
BESS (Tranche 2)			
Proposed Resources			
MPC PPA**	750	750	750
Santa Rosa PPA**	N/A	230	-
Robins BESS	N/A	128	-
Moody BESS	N/A	50	50
200 MW Co-Located Solar	N/A	-	-
Yates 8-10	N/A	-	-
Extension Options			
Scherer	N/A	645	645
Gaston	N/A	1,037	1,020

*Nameplate MW
**MPC and Santa Rosa end in 2028

N/A indicates resource was not included in Aurora as a selectable resource

The results of the MG20 case were consistent with the results of the MG0 case, in that when a lower load forecast was used, the model selected less CC and BESS resources. Also, once again, the model determined that it would be economic to extend the operation

of the Scherer and Gaston resources.[59] Another result of this CO_2 case is that the additional carbon pressure also led to the Robins and Moody BESS projects being selected. In other words, Robins and Moody was selected in the Company's load forecast case (middle column), and just Moody was selected in Staff's load forecast case shown in the rightmost column. Ultimately, a combination of MPC, Santa Rosa, Robins, and Moody, was selected economically to best fit the load projection in the carbon sensitivity scenarios.

MPC and Santa Rosa PPAs

Q. PLEASE DESCRIBE STAFF'S RECOMMENDATION REGARDING THE MPC PPA RESOURCE.

A. Staff proposes certification of the MPC PPA on a risk mitigation and economic basis. Staff finds there is a capacity need beginning in 2027, and since the MPC PPA consists of resources already in operation, acquisition of that PPA eliminates risks associated with attempting to construct resources in that short of a time period. Staff Witness Larkin addresses the Company's request for an additional sum and Staff's recommendation that all benefits from the resale of the PPAs should flow to Georgia Power customers.

Q. PLEASE EXPLAIN STAFF'S RECOMMENDATION REGARDING THE SANTA ROSA PPA.

[59] Staff examined the capacity factors of Scherer and Gaston for this case and found the units had capacity factors below 10% in the years reviewed.

A. The same considerations discussed above for the MPC PPA applies to the Santa Rosa PPA. Staff recommends certification of the Santa Rosa PPA along with the remarketing of the associated capacity when needed.

Additionally, the Company should provide an update in rebuttal testimony regarding the deliverability of the capacity following the January 12th Supplemental Filing it made, in which the Company stated:

> Furthermore, the Company updated the Santa Rosa PPA firm capacity based on the results of a Southern Company Native Load Reservation interface study report for the Santa Rosa PPA resource. While annual firm transmission cannot be confirmed for 2024 through May 2026, Georgia Power is pursuing and may obtain short-term firm transmission for the resource during this period. Consistent with the transmission screening analyses in the 2023 IRP Update, no transmission project costs are attributable to the Santa Rosa PPA.[60]

The Company should address the reasonableness of customers paying capacity payments for a resource that cannot secure annual firm transmission rights.

Yates 8-10 CT Resources

Q. WHAT INFORMATION HAS THE COMPANY PROVIDED TO SUPPORT ITS REQUEST FOR THE THREE NEW CT UNITS AT PLANT YATES?

A. The Company has provided a number of estimates for the costs and in-service dates for the Yates CT projects as shown in the table below. In the Company's initial 2023 IRP

[60] STF JKA 2-2 Supplemental

Update filing, noted "IRP Filing" in the table below, the Company provided a summary statement, a 3-page Technical Information Appendix document, and an economic analysis study with a financial model. The Company then filed a supplemental financial and economic analysis on January 12, 2024 that updated the Yates costs, which is noted as "Supplemental" in the table. Finally, the Company provided a certification filing on January 31, 2024, which is noted as "Certification" in the table. The table provides total in-service costs, which includes capital costs and financing costs for various capital cost components (generators, transmission, gas lateral).

Table 12: Yates CT Cost Summary

$ Billions	IRP Filing	Supplemental	Certification
U8, U9, U10 Only			
Spend Curve $	[redacted]		
In-Service $			
Tie Line and Gas Lateral			
Spend Curve $	[redacted]		
Inservice $			
Total			
Spend Curve $	[redacted]		
In-Service			
U8 COD	12/1/2026	12/1/2026	12/1/2026
U9 COD	12/1/2026	5/1/2027	5/1/2027
U10 COD	4/1/2027	8/1/2027	8/1/2027

Q. PLEASE EXPLAIN STAFF'S FINDINGS AND RECOMMENDATION REGARDING THE COMPANY'S PROPOSAL TO SELF BUILD THREE CTS AT YATES.

A. Staff recommends that the Company's request for additional CT capacity at Yates be denied given that no additional resources are needed before 2029, and the project is not an economic resource. The Company's latest assumption is that a portion of the Yates project (Yates Unit 8) will be available to serve load by the winter of 2026/2027 and all of the capacity would be completed by August 2027 (including Yates 9 and 10). However, Staff has demonstrated that the entire Yates project and the proposed BESS projects are not needed until 2029, and there is no reason that Yates should be selected based on an exception outside of the standard Commission required RFP process.

In addition, if Georgia Power were to contend that the 1,300 MW Yates project is needed before 2029, the Commission should be aware that due to transmission limits, only 600 MW of the project will be fully deliverable prior to 2029. That is because transmission upgrades will have to be constructed to ensure full deliverability of the Yates capacity, which will not occur until 2029, and possibly not until later if the transmission upgrades are delayed. Staff does not believe there would be any advantage in approving the Yates project now, as the project will not provide the full capacity any earlier than it would if it were required to go through an RFP selection process.

Finally, there is no proof that the Yates project is more economical than other peaking capacity that might be available from a market resource obtained via an RFP as indicated by Staff's Resource Mix Study results. Neither the Yates CT capacity, nor even generic CT capacity were selected prior to 2030 in Staff's Resource Mix cases. Staff does not recommend certification of the Yates project until it is determined to be a least-cost resource in a RFP process.

BESS (and Solar) Requests

Q. WHAT BESS PROJECTS HAS THE COMPANY CONTEMPLATED ACQUIRING IN THIS IRP UPDATE?

A. The Company has requested "[a]uthority to develop, own, and operate up to 1,000 MW of BESS at various sites…,"[61] and the Company states that these units could be brought "online by the end of 2027, inclusive of 378 MW for the proposed Robins, Moody, and BESS plus solar project."[62] The Company has requested flexibility to be able to add the remainder of the 1,000 MW, or 622 MW as needed to meet load requirements.

Q. WHAT BESS PROJECTS DOES THE COMPANY CURRENTLY HAVE AUTHORIZATION FOR?

[61] Georgia Power's 2023 IRP, Main Document, Request 4, p. 4.
[62] Georgia Power's 2023 IRP, Direct Testimony of Jeffrey Grubb, Francisco Valle, Lee Evans, and Michael Bush, p. 27, l. 2.

A. From the 2019 IRP, the Company has the authority to own and operate the Mossy Branch BESS project (65 MW), a 13 MW project at Ft. Stewart, and a 2 MW project at a distribution facility within the Company's service territory. From the 2022 IRP, the Company has the authority to own and operate the McGrau Ford (265 MW) BESS project and to conduct an RFP for an additional 500 MW of ESS projects.

With regard to the 500 MW ESS RFP, the Company has been inconsistent in its presentation of plans for that procurement. In the initial filing, the Company provided a load and resource balance table that indicated the Company would acquire the 500 MW 2022 IRP ESS RFP resources by the winter of 2029. The Company did not include the proposed new BESS resources (Robins, Moody and BESS plus Solar project) in that table. In response to Staff discovery STF-JKA-2-2f, the Company provided another load and resource balance table that included the proposed resources, but did not include the 500 MW 2022 IRP ESS RFP resources. The Company also included a line, "Other BESS," that appears to be the remainder of the 1,000 MW that the Company is seeking authorization in this proceeding to be able to add.[63] Staff understands the Company does intend to issue the 500 MW 2022 IRP ESS RFP, sometime in 2024.[64]

[63] The Company filed both an original Load and Resource balance workpaper in STF-JKA-2-2 and a supplemental workpaper, and both show the elimination of the 500 MW 2022 IRP ESS RFP resource, and the inclusion of the 560 MW "Other BESS" capacity.
[64] STF-JKA-5-3a.

Q. IF THE COMPANY'S 1,000 MW REQUEST IS APPROVED, HOW MUCH BESS CAPACITY FROM THIS AND PRIOR PROCEEDINGS WILL HAVE BEEN COMPETITIVELY PROCURED?

A. The following table shows all of the Company's BESS procurements, based on this IRP and approvals from prior proceedings.

Table 13: GPC Energy Storage Procurement Plan Summary (MW)

	Request
Mossy Branch (Owned)	65
Ft. Stewart 4-hr BESS (Owned)	13
Distribution Storage (Owned)	2
McGrau Ford (Owned)	265
2022 IRP Approved ESS (RFP)	500
2023 IRP Update Request (Owned)	1,000
Total	**1,845**

If the Company's request is approved in this proceeding, only 27% (500/1,830) of these BESS resources will have been acquired through a competitive procurement process. Furthermore, the Company has not even begun the 500 MW procurement process from the 2022 IRP, despite having been authorized to do so for more than a year and a half (since July 2022).

Q. ARE THE COMPANY'S PROPOSED OWNED RESOURCES COST COMPETITIVE COMPARED TO RESOURCES THAT COULD BE PROCURED IN THE MARKET?

A. No. The following table compares the Company's proposed BESS projects to the generic candidate BESS resource the Company modeled in the Company's Resource Mix Study, which is a proxy for what the Company believes that BESS resources could be acquired for in the market.

Table 14: BESS Cost Comparison (Rev. Req)

PVRR Comparison	GENERIC BESS (2027)	ROBINS BESS	MOODY BESS	CO-LOCATED BESS
Winter Credit	**300**	**115**	**44.5**	**200**
PVRR $/Winter kW				
Build Capital	[redacted]	[redacted]	[redacted]	[redacted]
Maintenance Capital				
FOM				
PVRR $/kW Total				

The table indicates that the least expensive Company-owned proposed project (Robins) is [redacted]% ([redacted]) more expensive than the generic candidate BESS resource. Furthermore, it is possible that BESS prices may fall a significant amount further in 2024, according to a recent report[65] by Clean Energy Associates.[66] Also, as noted above, the

[65] "BESS Prices in US Market to Fall a Further 18% in 2024, says CEA", Energy Storage News, February 7, 2024, https://www.energy-storage.news/bess-prices-in-us-market-to-fall-a-further-18-in-2024-says-cea/

[66] According to its website, Clean Energy Associates is a clean energy advisory company founded in 2008 with offices in Denver and Shanghai, with more than 200 professionals employed. https://www.cea3.com/about

RFI supports the notion that there may be more economic BESS projects available in the market.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED SELF-BUILD BESS PROJECTS?

A. Staff does not recommend certification of the Robins, Moody, or co-located solar and BESS projects until they are determined to be a least cost resource option from an RFP process. If the Company wants to acquire these projects, they should be included in the 500 MW ESS RFP process.

Staff's Ranking Analysis

Q. WHY DID STAFF PERFORM A RANKING ANALYSIS?

A. If the Commission were to decide a higher load forecast and / or an earlier capacity need date are appropriate, then a ranking analysis such as the one Staff performed could be used to assist in deciding which of the proposed resources to select. The purpose of Staff's Ranking Analysis was to determine the economic ordering of the proposed resources.

For example, if the Commission were to decide that one or more resources beyond MPC and Santa Rosa are needed, Staff's ranking analysis could be used to identify the next resource(s) that should be selected. Or if the Commission were to decide that a lower load forecast was appropriate and fewer resources were needed, Staff's

ranking analysis would again be helpful in deciding which resource to eliminate. In fact, for illustration purposes, Staff presents one additional lower load forecast case, based on a "P80" load forecast. The load and resource plan associated with this load forecast is presented as Table C in Exhibit NHW-4, which shows that even the Santa Rosa PPA would not be needed in the short-term period based on this case.

Q. PLEASE EXPLAIN THE MOTIVATION FOR USING THE P80 LOAD FORECAST IN STAFF'S ILLUSTRATIVE CASE.

A. The decision to use the P80 load forecast for Staff's illustrative case is that in the 2022 IRP Reserve Margin Study, the Company used an 80% confidence interval for the Value at Risk metric in its derivation of the Target Reserve Margin. In that study, the Company settled on a 26% Target Reserve Margin based on the determination that an 80% confidence interval would offer a reasonable balance between cost and reliability. In this IRP, the Company has proposed to use a 95% confidence level for the probabilistic LRM analysis associated with new large customer load. To be consistent in balancing cost and risk, Staff believes it would be reasonable to use an 80% confidence level, as was used in the Reserve Margin Study, for developing a lower load forecast sensitivity case. Consequently, Daymark produced a P80 LRM scenario with the Uniform success probability rates and wider delay assumptions that this panel used for the illustrative case.

Q. HOW DID STAFF CONDUCT ITS RANKING ANALYSIS STUDY?

A. Staff used the Company's Resource Mix Study database that contains a model of the Southern Company System, and then Staff added all of the proposed resources that the Company identified in the model and set them all to operate at the same time. Staff then performed Aurora runs, in which each proposed resource was removed one at a time, and Staff measured the $NPV/kW change (benefit) associated with the removal of each resource. A series of Aurora runs were performed on an iterative basis to compare results to determine which proposed resource was considered to be the least beneficial to the System. In the first round of the analysis, the least beneficial resource was identified, and it was removed from modeling. Another series of runs were made, and the next resource considered to have the least benefit out of the remaining units was identified and removed. The process continued each time by removing one unit, and ultimately Staff was able to determine the ranking order for the resources based on the benefits they could provide.

By performing this study using Aurora, an optimal ranking of the proposed resources could be identified. Staff preferred this approach as it remedied Staff's concerns with the term equalization issue, and satisfied Staff's goal of performing the analysis using a load-based dispatch approach. By using the Company's Resource Mix database, Staff was also able to use its preferred natural gas and CO_2 price forecasts.

Q. WHAT WERE THE RESULTS OF STAFF'S RANKING ANALYSIS?

A. The following table provides Staff's Ranking Analysis results, in which a "1" is considered the highest ranked resource and "6" is considered the lowest ranked resource. A supplemental filing was made on January 19, 2024, in which the Company updated Yates transmission costs, and another supplemental filing was made on January 31, 2024, in which the Company updated the Yates capital cost assumptions to support its Certification request. Staff's Ranking Analysis utilizes the latest Yates assumptions available. The results of Staff's study that was performed dynamically using the Aurora model are shown below. [67]

Table 15: Staff Ranking Analysis Summary

MG0	Staff Ranking
1	MPC PPA[68]
2	Robins BESS
3	Santa Rosa PPA
4	Moody BESS
5	Co-located BESS + Solar
6	Yates 8-10 CTs

Details of this analysis, including results by each round of the analysis are provided in Exhibit NHW-6.

[67] Staff's analysis also used Staff's load forecast and TRM assumptions but given the structure of the analysis – these assumptions did not fundamentally impact the ranking analysis function.

[68] Because MPC is composed of resources already part of the Southern Company System, it was not evaluated iteratively similar to the other proposed resources However, based on a preliminary analysis considering MPC's capacity cost, Staff determined MPC should be selected, and it was placed in the first ranking position in Staff's Ranking column.

VI. OTHER ISSUES

Flex Capacity Framework

Q. HAS STAFF REVIEWED THE FLEX CAPACITY FRAMEWORK?

A. Yes. The Company summarized the request:

> The Flex Capacity framework would authorize Georgia Power to undertake and recover the cost for preliminary development activities in connection with the development, operation, and ownership of new capacity resources. Additionally, the Company would be authorized to continue to explore PPA or acquisition options that could be presented for Commission approval and certification prior to the filing of the Company's 2025 IRP and recover any incremental cost incurred for this effort.[69]

Staff recommends that the Commission deny the Company's request. This framework has not been required in the past and does not afford customers any additional protections. The Company would file its 2025 IRP in January 2025, and therefore the request for interim relief is not required, as the Company could make new requests and present information to the Commission in that proceeding. Staff witness Ralph Smith provides additional discussion regarding the ratemaking implications of the Company's request.

Commission Rule 515-3-4-.04(3)(f)(7)

Q. HAS STAFF REVIEWED THE COMPANY'S NOTICE REGARDING THE COMMISSION RULE THAT WOULD REQUIRE GEORGIA POWER TO

[69] Geogia Power 2023 IRP Testimony, p. 50, l. 24.

MAINTAIN A PERCENTAGE OF THEIR CAPACITY AS "SELF-OWNED" RATEBASE ASSETS?

A. Yes. Staff has reviewed Commission Rule 515-3-4-.04(3)(f)(7), which states that the Company shall maintain a minimum percentage of all of its resources as "self-owned rate-based assets".[70] The rule does not state what the minimum percentage must be, but instead states the percentage should be set by Commission Order, and it states that the minimum percentage "may be changed from time to time." The Commission established the 70% minimum percentage amount when it issued its Final 2001 IRP Order in Docket No. 13305.[71]

Q. BESIDES INDICATING THE RULE MAY BE CHANGED FROM TIME TO TIME, DOES THE RULE PROVIDE THE COMMISSION FLEXIBILITY TO SUSPEND OR ADJUST THE MINIMUM PERCENTAGE REQUIREMENT?

A. Yes. An important part of the rule is that when a Company finds it is approaching the point of falling below the minimum percentage level, it is required to inform the Commission, so that the Commission, "in its discretion, may suspend these rules and provide guidance to the soliciting utility as to how it should proceed." The Company has provided notice to the Commission in this proceeding that it is approaching the point of

[70] https://rules.sos.state.ga.us/gac/515-3-4
[71] STF-JKA-2-17, Order issued July 17, 2001, at p. 21.

falling below the minimum percentage level, which it states will occur as early as the winter of 2026/2027.[72] However, by the plain language of the rule, it states the Commission has the discretion to suspend the rule, and to provide guidance to the utility as to how the utility should proceed.

Q. WHAT IS STAFF'S RECOMMENDATION?

A. Staff recommends that the Commission suspend the rule and not impose a minimum percentage requirement at this time. The Commission should wait to determine this after capacity RFPs are underway and the cost of third-party generation is known, which should occur prior to the 2025 IRP. At that time it can be determined whether third-party generation is more economical and just as reliable compared to Company owned generation. If such a determination is made, then the Commission could decide to reduce the minimum percentage requirement below 70%. At that time, the Commission will have the necessary information to make an informed decision.

In addition, the Company is now having to deal with extraordinary circumstances, and it should be permitted as much flexibility as possible to find solutions that are both reliable and economic. Finally, the Company has not provided any evidence of other utilities having a minimum percentage requirement of 70%, nor has the Company presented any evidence that since the 70% requirement went into place in 2001 that it has

[72] 2023 IRP Main Document, p. 18.

resulted in a more reliable low-cost system, or that any of its existing PPA's have underperformed. The Company should present evidence of this type to the Commission prior to the Commission reinstating use of the 70% minimum percentage requirement. Alternatively, a lower minimum percentage requirement should be established.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

BEFORE THE
GEORGIA PUBLIC SERVICE COMMISSION

In Re:

GEORGIA POWER COMPANY'S	**)**	**DOCKET NO. 55378**
2023 INTEGRATED RESOURCE	**)**	
PLAN UPDATE	**)**	

EXHIBITS

ON BEHALF OF THE

GEORGIA PUBLIC SERVICE COMMISSION
PUBLIC INTEREST ADVOCACY STAFF

FEBRUARY 15, 2023

EXHIBIT

STF-NHW-1

Exhibit STF-NHW-1
Tom Newsome Qualifications

Summary of Educational and Professional Experience of Tom J. Newsome

Mr. Newsome received a Bachelor of Chemical Engineering with certificates in Pulp & Paper and Polymers from the Georgia Institute of Technology in June 1986. In 1994, Mr. Newsome passed both required examinations and received a professional engineering license (PE) from the State of North Carolina. Mr. Newsome received a Master of Science in Business Economics and a Master of Science in Finance from Georgia State University in August 1996 and June 1997, respectively. Mr. Newsome is the recipient of the George J. Malanos Graduate Award for Academic Excellence for completing the finance program with a 4.0 grade-point average. In 2003, Mr. Newsome received Chartered Financial Analyst (CFA) designation from the CFA Institute after successfully completing three six-hour examinations on security analysis and portfolio management.

After graduation from Georgia Tech, Mr. Newsome worked as plant/process engineer for Shaw Industries, a carpet manufacturer. In April 1988, Mr. Newsome joined Weatherly, Inc., engineering and construction firm specializing in fertilizer plants, as a process engineer. Mr. Newsome's primary responsibilities were process design and plant start-ups, including start-ups in Korea and India. Mr. Newsome joined Midrex Direction Reduction Corp., an applied research, engineering and construction firm with proprietary iron ore processing plant technology in March 1993 as a process engineer. Mr. Newsome duties were similar to those at Weatherly, including assisting in the start-up of the world's largest Direct Reduction Iron plant in India.

Following graduation from graduate school at Georgia State, Mr. Newsome joined Georgia Gulf Corporation in 1997 as a corporate development analyst. While at Georgia Gulf, Mr. Newsome performed financial analysis and modeling for natural gas purchasing/hedging program, developed a "make-or-buy" model for methanol business, performed financial modeling for an acquisition, and calculated and summarized the financial performance of prior capital investments. In 1999, Mr. Newsome joined FMV Opinions, Inc. as a business valuation analyst and valued private companies for gift and estate tax, transactional and management planning purposes.

Mr. Newsome joined the Georgia Public Service Commission ("Commission") in January 2005 as a Financial Analyst/Economist. Mr. Newsome was promoted to Director of Utility Finance in 2008.

Mr. Newsome has testified in twenty-three Georgia Power Company ("Company" or "Georgia Power") proceedings before the Commission.

Mr. Newsome's most recent testimony was in Docket 29849 in 28th Vogtle Construction Monitoring ("VCM"). Prior to that, Mr. Newsome testified in Docket 44902 Fuel Cost Recovery (FCR-26). Prior to that Mr. Newsome's testified in Docket 29849 26th and 27th VCMs. Prior to that Mr. Newsome testified in Docket 44160 Integrated Resources Planning on supply side

resources. Prior to that Mr. Newsome testified in Docket 29849 23rd Vogtle Construction Monitoring ("VCM"), 24th VCM and 25th VCM on Vogtle economics. Prior to that was testimony in 22nd VCM and in Docket 43011 Fuel Cost Recovery (FCR-25) on the Company's hedging program and certain other issues. Prior to that Mr. Newsome's testified in Docket 29849 20th / 21st Vogtle Construction Monitoring ("VCM") on Vogtle economics. Prior to that Mr. Newsome's testified in Docket 42310 Georgia Power Company's 2019 Integrated Resource Plan on supply side and certain other issues. Prior to that testimony Mr. Newsome testified in Docket 29849 19th Vogtle Construction Monitoring ("VCM"), 18th VCM and 17th VCM on the economics of continuing Vogtle 3 and 4 construction and provided the Commission policy recommendations to protect ratepayers. Prior to testifying in the 17th VCM Mr. Newsome testified in the 2016 Integrated Resource Plan on the Company's requested to capitalize cost for investigation of new nuclear units. Mr. Newsome's testified in Docket No. 39638 Fuel Cost Recovery (FCR-24) on the Company's natural gas hedging program. In Docket No. 22403, Mr. Newsome addressed Georgia Power Company's natural gas hedging program and in Docket No. 24506 Mr. Newsome testified on the application of AFUDC accounting for calculating financing cost of capital projects. In Docket No. 27800, Certification of Plant Vogtle Expansion, Mr. Newsome addressed the sources, impact and mitigation of financial risk from the construction and operation of new nuclear units at Plant Vogtle. Mr. Newsome testified in Docket No. 29849 concerning Georgia Power's First Semi-annual Construction Monitoring Report on Plant Vogtle expansion. Mr. Newsome evaluated the economic analysis performed by Georgia Power and developed Staff's own independent economic and risk analysis of the Project. In the Second Vogtle Semi-annual hearing, Mr. Newsome testified on the Company's proposal to change how escalation on certain project cost was calculated (Amendment 3). In the Third Vogtle Semiannual hearing and in separate proceeding, Adoption of a Risk Sharing Mechanism, Mr. Newsome testified on Staff's revised risk sharing mechanism for Vogtle 3 & 4. In Docket No. 28945 Fuel Cost Recovery FCR–21, Mr. Newsome testified on seasonal rates. Mr. Newsome also presented cost of equity testimony in Atmos Energy Corporation's Rate Case in Docket No. 30442 and Generic Proceeding to Implement House Bill 168 (small telephone companies) in Docket No. 32235 in 2011 and 2018. Mr. Newsome provided testimony before the Commission in Georgia Power's 2013 Base Rate Case in Docket No. 36989 on the Company's projected cost of debt for 2014 – 2016. Mr. Newsome's primarily responsibility, prior to presenting testimony in these dockets, has been performing analyses of the parties' cost of equity capital positions in Docket Nos. 18638 (Atlanta Gas Light Company 2004/2005 Rate Case), 19758 (Savannah Electric and Power Company 2004 Rate Case), 20298 (Atmos Energy Corporation - Georgia Division 2005 Rate Case), 25060 (Georgia Power Co. 2007 Rate Case) and 27163 (Atmos Energy Corporation - Georgia Division 2008 Rate Case) and developing the Advisory PIA Staff's cost of equity recommendation to the Commission.

EXHIBIT

STF-NHW-2

EDUCATION/CERTIFICATION

M.S., Electrical Engineering, Georgia Institute of Technology, 1980
B.S., Electrical Engineering, Purdue University, 1979
Cooperative Education Certificate, Purdue University, 1979

PROFESSIONAL AFFILIATIONS

National Society of Professional Engineers
Georgia Society of Professional Engineers
Institute of Electrical and Electronic Engineers

EXPERIENCE

Since completing his Master's program, Mr. Hayet worked for fifteen years at Energy Management Associates, now Ventyx, providing consulting services and client service support to electric utility companies for the widely used planning models, PROMOD IV and STRATEGIST. Mr. Hayet had an instrumental role in designing some of the modeling features of those tools including the competitive market modeling logic in STRATEGIST.

In 1995, Mr. Hayet formed the utility consulting firm, Hayet Power Systems Consulting ("HPSC"), and worked for customers in the United States, and internationally in Australia, Japan, Singapore, Malaysia, the United Kingdom, and Vietnam. Mr. Hayet provided consulting services to Public Utility Commissions, Regional Power Pools, State Energy Offices, Consumer Advocate Offices, Electric Utilities, Global Power Developers, and Industrial Companies. Mr. Hayet's expertise covers a number of areas including utility system planning and operations, RTO analysis, market price forecasting, Integrated Resource Planning, renewable resource evaluation, transmission planning, demand-side analysis, and economic analysis.

In 2000, Mr. Hayet also joined the consulting firm of J. Kennedy & Associates, Inc. ("Kennedy and Associates") and assisted on projects that required utility resource planning, analysis, and software modeling expertise. Mr. Hayet merged his firm and became a Vice-President and Principal of Kennedy and Associates in 2015.

Mr. Hayet has conducted numerous consulting studies in the areas of RTO Cost/Benefit Analysis, Renewable Resource Evaluation, Renewable Portfolio Standards Evaluation, Electric Market Price Forecasting, Generating Unit Cost/Benefit Analysis, Integrated Resource Planning, Demand-Side Management, Load Forecasting, Rate Case Analysis and Regulatory Support.

2000 to Present: **J. Kennedy and Associates, Inc.**
Vice President and Principal

- Initially began as Director of Consulting, became Vice President and Principal in 2015
- Managed electric related consulting projects.
- Responsible for business development.
- Clients include Staffs of Public Utility Commissions and other State Agencies, State Energy Offices, Global Power Developers, and Industrial Groups, and large energy users.

1996 to Present: Hayet Power Systems Consulting
President and Principal

- Managed electric utility related consulting projects
- Clients include Staffs of Public Utility Commissions and other State Agencies, State Energy Offices, Global Power Developers, and Industrial Groups, and large energy users.

1991 to 1996: EDS Utilities Division, Atlanta, GA (Now Ventyx)
Lead Consultant, PROSCREEN (Now STRATEGIST) Department

- Managed a client services software team that supported approximately 75 users of the STRATEGIST electric utility strategic planning software.
- Participated in the development of STRATEGIST's competitive market modeling features and the Network Economy Interchange Module
- Provided client management direction and support, and developed new consulting business opportunities.
- Performed system planning consulting studies including integrated resource planning, DSM analysis, marketing profitability studies, optimal reserve margin analyses, etc.
- Based on experience with PROMOD IV, converted numerous PROMOD IV databases to STRATEGIST, and performed benchmark analyses of the two models.

1988 to 1991: Energy Management Associates (EMA), Atlanta, GA
Manager, Production Analysis Department

- Served as Project Manager of a database modeling effort to create an integrated utility operations and generation planning database. Database items were automatically fed into PROMOD IV.
- Supervised and directed a staff of five software developers working with a 4GL database programming language.

- Interfaced with clients to determine system software specifications, and provide ongoing client training and support

1980 to 1988: Energy Management Associates (EMA), Atlanta, GA
Senior Consultant, PROMOD IV Department

- Provided client service support to EMA's base of over 70 electric utility customers using the PROMOD IV probabilistic production cost simulation software.
- Provided consulting services in a number of areas including generation resource planning, regulatory support, and benchmarking.

TESTIMONY AND EXPERT WITNESS APPEARANCES

Date	Case	Jurisdict	Party	Utility	Subject
09/98	97-035-01	UT	Utah Committee for Consumer Services	PacifiCorp	Utah jurisdictional Net Power Costs, PacifiCorp Rate Case Proceeding
07/01	01-035-01	UT	Utah Committee for Consumer Services	PacifiCorp	Utah Jurisdictional Net Power costs in General Rate Case
2001	ER00-2854-000	FERC	Louisiana Public Service Commission	Entergy	Proposed System Agreement Modifications
07/02	02-035-002	UT	Utah Committee for Consumer Services	PacifiCorp	Special contract for industrial consumer
2002/ 2003	U-25888	LA	Louisiana Public Service Commission	Entergy	Investigation of retail issues related to the System Agreement
2003	U-27136 Subdocket A	LA	Louisiana Public Service Commission Staff	Entergy	Aging gas steam-fired retirement study
07/03	EL01-88-000	FERC	Louisiana Public Service Commission	Entergy	Rough production cost equalization proceeding
05/04	03-035-14	UT	Utah Committee for Consumer Services	PacifiCorp	Development of a large QF avoided cost methodology
06/04	18687-U 18688-U	GA	Georgia Public Service Commission Staff	Georgia Power and Savannah Electric	2004 Integrated Resource Planning Studies
08/04	ER03-583-000	FERC	Louisiana Public Service Commission	Entergy	Affiliate power purchase agreements
11/04	03-035-19	UT	Utah Committee for Consumer Services	PacifiCorp	Industrial customer's request for a special economic development tariff
11/04	03-035-38	UT	Utah Committee for Consumer Services	PacifiCorp	Large QF proceeding.
03/05	03-035-14	UT	Utah Committee	PacifiCorp	Concerning PacifiCorp's Schedule 38

Date	Case	Jurisdict	Party	Utility	Subject
			for Consumer Services		avoided cost tariff and remaining unsubscribed capacity
07/05	03-035-14	UT	Utah Committee for Consumer Services	PacifiCorp	Concerning PacifiCorp's Schedule 38 avoided cost proceeding
12/05	04-035-42	UT	Utah Committee for Consumer Services	PacifiCorp	Net power costs in General Rate Case
04/06	05-035-54	UT	Utah Committee for Consumer Services	PacifiCorp	Certification request to expand Blundell Geothermal Power Station. Related to Mid-American Energy Holding's Acquisition of PacifiCorp
05/06	22403-U	GA	Georgia Public Service Commission Staff	Georgia Power and Savannah Electric	March 2006 fuel cost recovery filing
2006	06-35-01	UT	Utah Committee for Consumer Services	PacifiCorp	2006 rate case, net power costs
08/06	U-21453	LA	Louisiana Public Service Commission Staff	Entergy Gulf States	Jurisdictional separation.
11/06	U-25116	LA	Louisiana Public Service Commission Staff	Entergy Louisiana	Fuel adjustment clause filings
01/07	23540-U	GA	Georgia Public Service Commission Staff	Georgia Power	November 2005 fuel cost recovery filing
04/07	07-035-93	UT	Utah Committee for Consumer Services	PacifiCorp	General Rate Case
06/07	24505-U	GA	Georgia Public Service Commission Staff	Georgia Power	2007 Integrated Resource Planning
10/07	U-30334	LA	Louisiana Public Service Commission Staff	Cleco Power	2008 Short-Term RFP
04/08	26794-U (FCR-20)	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing

Exhibit STF-NHW-2
Philip Hayet Qualifications

Date	Case	Jurisdict	Party	Utility	Subject
2008	6630-CE-299	WI	Wisconsin Industrial Energy Group, Inc.	WEPCO	Certification Proceeding for environmental upgrades at Oak Creek power plant
07/08	ER07-956	FERC	Louisiana Public Service Commission	Entergy	2006 rough production cost equalization compliance filing in the System Agreement case
09/08	6680-CE-180	WI	Wisconsin Industrial Energy Group, Inc.	Wisconsin Power and Light	Certification proceeding concerning Nelson-Dewey coal-fired generating unit
11/08	08-1511-E-GI	WV	West Virginia Energy Users Group	Allegheny Power	Fuel cost recovery filing
12/08	27800-U	GA	Georgia Public Service Commission Staff	Georgia Power	Vogtle 3 and 4 nuclear unit certification proceeding
2008	08-035-35	UT	Utah Committee for Consumer Services	PacifiCorp	Chehalis Combine Cycle Power Plant based on a waiver of the RFP solicitation process certification proceeding
07/09	ER08-1056	FERC	Louisiana Public Service Commission	Entergy	2007 rough production cost equalization compliance filing in the System Agreement case
07/09	U-30975	LA	Louisiana Public Service Commission Staff	SWEPCO and Cleco	Application to acquire the Oxbow Mine to supply Dolet Hills Power Station certification proceeding
09/09	E015/PA-09-526	MN	Large Power Intervenors	Minnesota Power	Request for approval to purchase Square Butte's 500 kV DC transmission line, restructure a coal based power purchase agreement
09/09	09-035-23 Direct	UT	Utah Office of Consumer Services	PacifiCorp	2009 rate case, net power costs
10/09	09A-415E	CO	Public Utilities Commission of Colorado	Black Hills/Colorado	CPCN application to construct two LMS 100 natural gas combustion turbine units
10/09	09-035-23 Surrebuttal	UT	Utah Office of Consumer Services	PacifiCorp	2009 rate case, net power costs
12/09	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	First Semi-Annual Vogtle Construction Monitoring Report

Exhibit STF-NHW-2
Philip Hayet Qualifications

Date	Case	Jurisdict	Party	Utility	Subject
12/09	ER08-1224	FERC	Louisiana Public Service Commission	Entergy	2008 production costs used to develop bandwidth payments
2009	09-2035-01	UT	Utah Office of Consumer Services	PacifiCorp	2008 IRP
01/10	28945-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing
2010	EL09-61	FERC	Louisiana Public Service Commission	Entergy	System Agreement, individual operating company sales
06/10	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Second Semi-Annual Vogtle Construction Monitoring Report
12/10	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Third Semi-Annual Vogtle Construction Monitoring Report
01/11	ER09-1350 Direct	FERC	Louisiana Public Service Commission	Entergy	2008 production costs used to develop bandwidth payments
02/11	ER09-1350 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy	2008 production costs used to develop bandwidth payments
04/11	33302-U (FCR-22)	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing
06/11	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fourth Semi-Annual Vogtle Construction Monitoring Report
09/11	U-31892	LA	Louisiana Public Service Commission Staff	Cleco Power	Settlement agreement, CPCN to upgrade Madison 3 coal unit to accommodate biomass fuel
11/11	26550-U	GA	Georgia Public Service Commission Staff	Georgia Power	Reacquisition of wholesale block capacity
11/11	34218-U	GA	Georgia Public Service Commission Staff	Georgia Power	Decertification of two aging coal units, acquire PPA resources, approve IRP update

Exhibit STF-NHW-2
Philip Hayet Qualifications

Date	Case	Jurisdict	Party	Utility	Subject
12/11	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fifth Semi-Annual Vogtle Construction Monitoring Report
03/12	U-32148	LA	Louisiana Public Service Commission Staff	Entergy	Change of Control Proceeding to move to Midwest ISO
2012	20000-EA-400-11	WY	Wyoming Industrial Energy Consumers	Rocky Mountain Power	Certification of environmental upgrades at Naughton 3
05/12	35277-U (FCR-23)	GA	Georgia Public Service Commission Staff	Georgia Power	Fuel cost recovery filing
05/12	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Sixth Semi-Annual Vogtle Construction Monitoring Report
07/12	2012-00063	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers	Environmental upgrades in compliance with MATS and CSAPR
09/12	U-32275	LA	Louisiana Public Service Commission Staff	Dixie Electric Member Cooperative	Ten year power supply acquisition certification proceeding
12/12	EL09-61-002 Direct	FERC	Louisiana Public Service Commission	Entergy	Harm calculation, violation of System Agreement
12/12	U-32557	LA	Louisiana Public Service Commission Staff	Entergy	Certification of 28 MW PPA for renewable energy capacity (RAIN waste heat) in accordance with LPSC's Renewable Energy Pilot
12/12	U-29764	LA	Louisiana Public Service Commission Staff	Entergy	Retail proceeding regarding termination of cross-PPAs
12/12	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Seventh Semi-Annual Vogtle Construction Monitoring Report
03/13	EL09-61-002 Cross-Answering	FERC	Louisiana Public Service Commission	Entergy	Harm calculation, violation of System Agreement
04/13	2012-00578	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power Company	Mitchell Certificate of Public Convenience and Necessity

Exhibit STF-NHW-2
Philip Hayet Qualifications

Date	Case	Jurisdict	Party	Utility	Subject
05/13	36498-U	GA	Georgia Public Service Commission Staff	Georgia Power	2013 IRP and request to decertify over 2,000 MW of coal-fired capacity
07/13	U-32785	LA	Louisiana Public Service Commission Staff	Entergy	8.5 MW PPA for renewable energy capacity (Agrilectric rice hull) in accordance with LPSC's Renewable Energy Pilot
08/13	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Eighth Semi-Annual Vogtle Construction Monitoring Report
10/13	2013-00199	KY	Kentucky Industrial Utility Customers, Inc.	Big Rivers	Base rate case
05/14	13-035-184	UT	Utah Office of Consumer Services	PacifiCorp	2014 General Rate Case, net power cost
06/14	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Ninth/Tenth Semi-Annual Vogtle Construction Monitoring Report
07/14	20000-446-EA-14	WY	Wyoming Industrial Energy Consumers	PacifiCorp	2014 General Rate Case, net power cost
08/14	2000-447-EA-14	WY	Wyoming Industrial Energy Consumers	PacifiCorp	2014 Energy Cost Adjustment Mechanism application
08/14	14-035-31	UT	Utah Office of Consumer Services	PacifiCorp	2014 Energy Balancing Adjustment application
09/14	ER13-432	FERC	Louisiana Public Service Commission	Entergy	Allocation of Union Pacific Settlement Agreement benefits
10/14	2014-00225	KY	Kentucky Industrial Utility Customers, Inc.	Kentucky Power	Kentucky Power Company's Fuel Adjustment Clause
12/14	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Eleventh Semi-Annual Vogtle Construction Monitoring Report
05/15	14-035-140	UT	Utah Office of Consumer Services	PacifiCorp	Solar and wind capacity contribution avoided cost proceeding.
06/15	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twelfth Semi-Annual Vogtle Construction Monitoring Report

Exhibit STF-NHW-2
Philip Hayet Qualifications

Date	Case	Jurisdict	Party	Utility	Subject
08/15	15-035-03	UT	Utah Office of Consumer Services	PacifiCorp	2015 Energy Balancing Adjustment application
09/15	14-035-114	UT	Utah Office of Consumer Services	PacifiCorp	Cost and Benefits of PacifiCorp's Net Metering Program
11/15	39638-U	GA	Georgia Public Service Commission Staff	Georgia Power	FCR-24 Fuel Cost Recovery Proceeding
11/15	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Thirteenth Semi-Annual Vogtle Construction Monitoring Report
5/16	40161	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power Company's 2016 IRP and Application for Decertification of Plant Mitchell Units 3, 4A, and 4B, Kraft Unit 1 CT, and Intercession City CT
6/16	29849	GA	Georgia Public Service Commission Staff	Georgia Power	Fourteenth Semi-Annual Vogtle Construction Monitoring Report
8/16	16-035-27	UT	Utah Office of Consumer Services	PacifiCorp	Renewable Energy Services Contract between Rocky Mountain Power and Facebook, Inc
8/16	16-035-01	UT	Utah Office of Consumer Services	PacifiCorp	2016 Energy Balancing Adjustment application
9/16	09-035-15	UT	Utah Office of Consumer Services	PacifiCorp	EBA Pilot Evaluation Direct Testimony
11/16	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Fifteenth Semi-Annual Vogtle Construction Monitoring Report
11/16	09-035-15	UT	Utah Office of Consumer Services	PacifiCorp	EBA Pilot Evaluation Rebuttal Testimony
11/16	EL09-61-04	FERC	Louisiana Public Service Commission	Entergy	Violation of System Agreement, Phase III, Harm Calculation, Direct
3/17	EL09-61-04	FERC	Louisiana Public Service Commission	Entergy	Violation of System Agreement, Phase III, Harm Calculation, Rebuttal
6/17	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Sixteenth Semi-Annual Vogtle Construction Monitoring Report

Exhibit STF-NHW-2
Philip Hayet Qualifications

Date	Case	Jurisdict	Party	Utility	Subject
9/17	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Direct
11/17	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Surrebuttal
4/18	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Response
4/18	17-035-39	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision to Repower Wind Facilities, Rebuttal to Response
12/17	17-035-40	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision for New Wind and New Transmission, Direct
1/18	17-035-40	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision for New Wind and New Transmission, Rebuttal
4/18	17-035-40	UT	Utah Office of Consumer Services	PacifiCorp	Approval of Resource Decision for New Wind and New Transmission, Second Rebuttal
6/18	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Eighteenth Semi-Annual Vogtle Construction Monitoring Report
8/18	Cause 45052	IN	Indiana Coal Council	Vectren Energy Delivery of Indiana	Request for Approval of an 850 MW CCGT Plant
9/18	U-34836	LA	Louisiana Public Service Commission Staff	Entergy Louisiana, LLC	Authorization to Participate in a 50 MW Solar PPA
11/18	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Nineteenth Semi-Annual Vogtle Construction Monitoring Report
1/19	U-35019	LA	Louisiana Public Service Commission Staff	Entergy Louisiana	Authorization to Make Available Experimental Renewable Option and Rate Schedule RTO
4/19	42310-U	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power's 2019 IRP Proceeding
11/19	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty/Twenty-First Semi-Annual Vogtle Construction Monitoring Report

Exhibit STF-NHW-2
Philip Hayet Qualifications

Date	Case	Jurisdict	Party	Utility	Subject
5/20	43011-U	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power Fuel Cost Recovery Application (FCR-25)
6/20	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Second Semi-Annual Vogtle Construction Monitoring Report
7/20	17-035-61	UT	Utah Office of Consumer Services	Rocky Mountain Power	Approval of an Export Credit Rate for Customer Generators (Primarily Rooftop Solar)
9/20	20-035-04	UT	Utah Office of Consumer Services	Rocky Mountain Power	Utah Rate Case
10/20	2019-226-E	SC	South Carolina Office of Regulatory Services	Dominion Energy South Carolina	Review of DESC's 2020 IRP
10/20	2019-227-E	SC	South Carolina Office of Regulatory Services	Lockhart Power Company	Review of Lockhart Power Company's 2020 IRP
11/20	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Third Semi-Annual Vogtle Construction Monitoring Report
12/20	20-035-01	UT	Utah Office of Consumer Services	Rocky Mountain Power	Application for Approval of the 2020 Energy Balancing Account
2/21	2019-224 and 225-E	SC	South Carolina Office of Regulatory Services	Duke Energy Carolinas and Duke Energy Progress	Review of Duke Energy's 2020 IRP
6/21	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Fourth Semi-Annual Vogtle Construction Monitoring Report
9/21	U-35927	LA	Louisiana Public Service Commission	1803 Electric Cooperative	Compliance with MBM Order in Conducting RFP and Acquiring Resources
12/21	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Fifth Semi-Annual Vogtle Construction Monitoring Report

Date	Case	Jurisdict	Party	Utility	Subject
5/22	44160-U	GA	Georgia Public Service Commission Staff	Georgia Power	Georgia Power's 2022 IRP Proceeding
6/22	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Sixth Semi-Annual Vogtle Construction Monitoring Report
12/22	22-035-01	UT	Utah Office of Consumer Services	Rocky Mountain Power	Application for Approval of the 2022 Energy Balancing Account
12/22	2022-259-E	SC	South Carolina Office of Regulatory Services	Dominion Energy South Carolina, Inc.	Mid-Period Adjustment to Increase Base Rates for the Recovery of Electric Fuel Costs
1/23	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Seventh Semi-Annual Vogtle Construction Monitoring Report
06/23	2023-9-E	SC	South Carolina Office of Regulatory Services	Dominion Energy South Carolina, Inc.	Review of DESC's 2023 IRP
7/23	29849-U	GA	Georgia Public Service Commission Staff	Georgia Power	Twenty-Eighth Semi-Annual Vogtle Construction Monitoring Report
09/23	2023-154-E	SC	South Carolina Office of Regulatory Services	South Carolina Public Service Authority	Review of Santee Cooper's 2023 IRP
11/23	23-0735-E	WV	West Virginia Energy Users Group	Mon Power and Potomac Edison	Expanded Net Energy Cost proceeding.
12/23	U-36974	LA	Louisiana Public Service Commission Staff	1803 Electric Cooperative, Inc.	Application for Certification of a Capacity Purchase Agreement.

ADDITIONAL JUDICIAL PROCEEDINGS AND OTHER PROJECT INFORMATION

- 1995 – 2000 - Modeled the Singapore Power Electricity System and analyzed the benefits of dispatching a new oil-fired unit within the system, BHP Power

- 1995 – 2000 - Modeled the Australian National Energy Market to develop market based energy price forecasts on behalf of an Independent Power Producer in Australia, BHP Power
- 1995 – 2000 - Analyzed the benefit of purchasing existing gas-fired steam turbine units within the Australian market, BHP Power
- 1995 – 2000 Developed market price forecasts for South Australia as part of the evaluation of a new gas fired combined cycle unit, BHP Power
- 1995 – 2000 - Modeled the Vietnam Electricity System as part of a project to develop Least Cost Expansion plans for Vietnam, EVN State Utility
- 1995 – 2000 - Assisted in the evaluation of Phu My CCGT power plant in Vietnam, BHP Power
- 1995 – 2000 - Assisted in the development of Market Price Forecasts in several regions of the US. These forecasts were used as the basis for stranded cost estimates, which were filed in testimony in a number of jurisdictions across the country.
- 1995 – 2000 - Conducted research regarding ISO Tariffs and Operations for the PJM Power Pool, the California ISO, and the Midwest ISO on behalf of a Japanese Research.
- 1995 – 2000 - Performed research on numerous electric utility issues for 3 Japanese research organizations. This was primarily related to deregulation issues in the US in anticipation of deregulation being introduced in Japan.
- 1995 – 2000 - Critiqued the IRP filings of 5 utilities in South Carolina on behalf of the South Carolina State Energy Office
- 1999 - Helped to analyze the rate structure and develop an electricity price forecast for the Metropolitan Atlanta Rapid Transit Authority (MARTA) in Atlanta, Georgia
- August 2002 – Expert Report, Civil Action No. 1:00-cv-1262 in the United Stated District Court for the Middle District of North Carolina, United States v. Duke Energy Corporation, Department of Justice
- 2002 - Worked on behalf of the Utah Committee of Consumer Services to provide guidance and assist in the analysis of PacifiCorp's 2002 Integrated Resource Plan.
- July 2003 - Worked on behalf of the Oregon Public Utility Commission to Audit PacifiCorp's Net Power Costs per a Settlement Agreement accepted by the Public Utility Commission of Oregon in its Order No. 01-787. Audit report in Docket No. UE-116 filed July 2003.
- 2003 - Regulatory support to the Utah Committee of Consumer Services regarding PacifiCorp's 2003 Utah General Rate Case Docket # 03-2035-02.

- 2004 – Assistance to the Utah Committee of Consumer Services to analyze a series of power purchase agreements and special contracts between PacifiCorp and several of its industrial customers.
- 2005 - Worked on behalf of the Utah Committee of Consumer Services to help analyze PacifiCorp's restructuring proposals.
- 2005 - Assisted the Utah Committee of Consumer Services by evaluating PacifiCorp's 2005 IRP and assisted in writing comments that were filed with the Commission.
- 2007 - Assisted the Utah Committee of Consumer Services to evaluate PacifiCorp's 2007 IRP.
- 2007 - Conducted an investigation of the Southern Company interchange accounting and fuel accounting practices on behalf of the Georgia Public Service Commission Staff (Docket 21162-U).
- 2008 - Assisted the Louisiana Public Service Commission Staff with the review and evaluation of Cleco Power's 2008 Short Term RFP and its 2010 Long-Term RFP.
- 2008 - Assisted the Utah Committee of Consumer Services by participating in a collaborative process to develop an avoided cost tariff for large QFs.
- 2008 - Assisted the Louisiana Public Service Commission Staff with a rulemaking for the opportunity to implement a Renewable Portfolio Standard in Louisiana. (Docket No. R-28271 Sub-Docket B)
- April 2011 – Initial Expert Report, Civil Action No. 2:10-cv-13101-BAF-RSW, on behalf of the Department of Justice in US District Court, United States v.Detroit Edison
- June 2011 – Rebuttal Expert Report, Civil Action No. 2:10-cv-13101-BAF-RSW, on behalf of the Department of Justice in US District Court, United States Detroit Edison
- 2011 - Assisted the Georgia Public Service Commission Staff to investigate the acquisition of additional coal and combustion turbine capacity currently wholesale capacity (Docket 26550).
- 2012 - Assisted the Louisiana Public Service Commission Staff with a rulemaking to design Integrated Resource Planning ("IRP") rules. (Docket No. R-30021)
- December 2013 – Expert Report, Civil action no. 4:11-cv-00077-RWS, on behalf of the Department of Justice in US District Court, United States v. Ameren Missouri.

PUBLICATIONS AND PRESENTATIONS

Co-authored "Review of EPA's Section 111 May 23, 2023 Proposed Rule for the State of South Carolina", on behalf of South Carolina Office of Regulatory Staff, August 2023.

Co-authored "Review of EPA's Section 111(d) CO_2 Emission Rate Goals for the State of Montana, on behalf of the Montana Large Customer Group, October 2014.

Authored "Singapore's Developing Power Market", which appeared in the July/August 1999 edition of Power Value Magazine

Co-authored "The New Energy Services Industry – Part 1", which appeared in the January/February 1999 edition of Power Value Magazine.

Co-authored and Presented "Evaluation of a Large Number of Demand-Side Measures in the IRP Process: Florida Power Corporation's Experience", Presented at the 3rd International Energy and DSM Conference, Vancouver British Columbia, November 1994

Co-authored "Impact of DSM Program on Delmarva's Integrated Resource Plan", Published in the 4th International Energy and DSM Conference Proceedings, held in Berlin, Germany, 1995

Presentation – Law Seminars International, Electric Utility Rate Cases, Case Study of the Louisiana Public Service Commission's Quick Start Energy Efficiency Program, March 2015.

EXHIBIT

STF-NHW-3

EDUCATION

M.S. Operations Research, Georgia Institute of Technology, 2017
B.S. Mathematics, Georgia Southern University, 2012

PROFESSIONAL AFFILIATIONS

Women's Energy Network, Greater Atlanta Chapter – Board Member (2019 – 2023)
Women's Energy Network, Greater Atlanta Chapter – Member (2016 – Present)

EXPERIENCE

Ms. Wellborn has been working in regulated energy markets since early 2013. She has an undergraduate degree in mathematics and graduate degree in operations research. She started her career working at J. Kennedy and Associates, Inc., and sub-contracting to Hayet Power Systems Consulting. For these companies, she provided critical support in the areas of production cost modeling and data analysis through 2018. Ms. Wellborn then spent nearly 3 years at Accenture, supporting its global regulated energy team within the procurement practice, helping large commercial and industrial clients manage their energy spend and energy related initiatives, as they related to regulated utility tariffs, economic dispatch, planning, and market risk (energy efficiency, green tariffs, PPA/VPPA, etc.). Ms. Wellborn rejoined J. Kennedy and Associates in late 2021, and currently provides analytical support to clients in the areas of utility resource planning and market modeling.

2021 to Present: **J. Kennedy and Associate, Inc.**
Manager, Consulting

Performs analysis and prepares expert witness testimony on utility planning studies and economic evaluations in review of electric utility regulatory filings. Clients included State Public Service Commissions, Industrial Users Groups, and Consumer Advocacy Groups.

2019 to 2021: **Accenture, LLP**
Associate Manager, Global Lead - Regulated Energy Procurement

As a part of Accenture Operations' Energy Management and Procurement practice, the Regulated Energy team helps clients identify opportunities for electricity and natural gas cost savings through data analysis and deep industry experience. Clients include large industrial and commercial end-use customers with locations spread across multiple geographies and utility service territories.

• Conducts tariff optimization analysis and ad hoc economic decision analysis for clients with operations and energy spend in areas served by regulated electricity and natural gas distribution utilities.

• Leads cross functional international delivery team of 10, providing career counseling and project oversight. Supports international energy procurement functions as they relate to regulated utilities/energy markets of Australia, Southeast Asia, and Latin America.
• Manages project assessments and economic studies as they relate to resource planning or capacity/energy market risk and dispatch pricing (renewables, time-of-use tariffs, real-time-pricing/avoided cost, PPA, VPPA, etc.)
• Collaborates with all energy management work streams - including utility bill management, renewable energy procurement, deregulated markets competitive sourcing, market intelligence, and project management/technology development initiatives to manage customer spend end to end.

2013 to 2019: **J. Kennedy and Associate, Inc.**
Senior Consultant

Responsible for conducting research, performing data analysis, developing production-cost model input assumptions and running production-cost studies, analyzing model output, and conducting related economic studies.

CERTIFICATIONS

Energy Exemplar – Aurora Core Certification Course (March 2022)
Energy Exemplar – PLEXOS Power Core Certification Course (June 2023)

CLIENTS SERVED

Georgia Public Service Commission Staff
Louisiana Public Service Commission Staff
Kentucky Industrial Utility Customers, Inc.
Utah Office of Consumer Services
South Carolina Office of Regulatory Staff
Wisconsin Industrial Energy Group

TESTIMONY AND EXPERT WITNESS APPEARANCES

Date	Case	Jurisdict	Party	Utility	Subject
06/18	29849	GA	Georgia Public Service Commission Staff	Georgia Power	Eighteenth Semi-Annual Vogtle Construction Monitoring Report
11/18	29849	GA	Georgia Public Service Commission Staff	Georgia Power	Nineteenth Semi-Annual Vogtle Construction Monitoring Report
5/22	44160	GA	Georgia Public Service Commission Staff	Georgia Power	2022 Integrated Resource Plan (Supply Side Resource Plan, Aurora)
10/22	44280	GA	Georgia Public Service Commission Staff	Georgia Power	2022 Rate Case (Revenue Forecast)
8/23	2023-9-E	SC	South Carolina Office of Regulatory Staff	Dominion Energy South Carolina, Inc.	2023 Integrated Resource Plan
12/23	2023-154-E	SC	South Carolina Office of Regulatory Staff	South Carolina Public Service Authority (Santee Cooper)	2023 Integrated Resource Plan
12/23	36974	LA	Louisiana Public Service Commission Staff	1803 Electric Cooperative, Inc.	Application for Certification of a Capacity Purchase Agreement.

REPORTS AND INDUSTRY PUBLICATIONS

Date	Title	Author(s)
8/23	Review of EPA's Section 111 May 23, 2023 Proposed Rule for the State of South Carolina	J. Kennedy and Associates, Inc. (On behalf of the South Carolina Office of Regulatory Staff)

EXHIBIT

STF-NHW-4

Company Load and Resource Balance without Planned Resources (based on Staff's load forecast and TRM)

Table A	Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
line	**Owned Generating Capacity (MW))**	**14,770**	**15,403**	**15,405**	**15,737**	**15,737**	**14,732**	**14,734**	**14,734**	**14,734**	**14,734**	**14,734**	**14,044**
1	As modeled by GPC	14,770	15,341	15,343	15,706	15,706	14,702	14,703	14,703	14,703	14,703	14,703	14,013
2	Hydro Modernization Adjustment	0	0	0	31	31	31	31	31	31	31	31	31
3	Mossy Branch Availability (2025-2026)	0	62	62	0	0	0	0	0	0	0	0	0
4	Staff assumed extensions Scherer and Gaston	0	0	0	0	0	0	0	0	0	0	0	0
line	**Proposed Resource Capacity (MW)**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
5	GPC Proposed MPC PPA less Sale	0	0	0	0	0	0	0	0	0	0	0	0
6	GPC Proposed Santa Rosa PPA	0	0	0	0	0	0	0	0	0	0	0	0
7	GPC Proposed Robins BESS	0	0	0	0	0	0	0	0	0	0	0	0
8	GPC Proposed Moody BESS	0	0	0	0	0	0	0	0	0	0	0	0
9	GPC Proposed Co-located Solar + BESS	0	0	0	0	0	0	0	0	0	0	0	0
10	GPC Proposed Yates 8-10	0	0	0	0	0	0	0	0	0	0	0	0
11	GPC Proposed Remaining 1000 MW BESS	0	0	0	0	0	0	0	0	0	0	0	0
12	**Purchased Generating Capacity (MW)**	**4,535**	**5,149**	**5,222**	**5,222**	**5,478**	**5,178**	**5,178**	**3,124**	**3,124**	**3,069**	**3,066**	**1,749**
13	Existing Contracts	4,535	5,149	5,222	5,222	5,478	5,178	5,178	3,124	3,124	3,069	3,066	1,749
14	2022 IRP Planned Renewable	0	0	0	0	0	0	0	0	0	0	0	0
15	2022 IRP Planned ESS	0	0	0	0	0	0	0	0	0	0	0	0
16	**Dispatchable DSOs (MW)**	**675**	**696**	**716**	**758**	**805**	**750**	**752**	**750**	**749**	**749**	**749**	**749**
17	Existing Programs (CVR, DPEC, RTP, TempCheck)	675	675	669	669	657	602	604	602	601	601	601	601
18	DER Customer Program (2022 IRP)	0	21	47	89	148	148	148	148	148	148	148	148
19	Staff Assumed Additional Demand Response												
20	**Total Capacity (MW)**	**19,980**	**21,248**	**21,343**	**21,718**	**22,020**	**20,661**	**20,663**	**18,608**	**18,607**	**18,552**	**18,548**	**16,542**
21	**Winter Peak Demand Forecasts**												
22	Uniform w/Delays P95	15,202	15,513	16,041	17,699	18,470	19,084	19,768	20,375	20,666	20,888	21,040	21,145
23	**Winter Target Reserve Margin (Staff)**	22.94%	22.94%	22.94%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%
24	**Capacity Required to Meet Target (MW)**												
25	Uniform w/Delays P95	(1,291)	(2,176)	(1,622)	**143**	**793**	**2,911**	**3,753**	**6,559**	**6,919**	**7,248**	**7,440**	**9,576**

Staff Plan (based on Staff's load forecast and TRM)

Table B	Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
line	**Owned Generating Capacity (MW))**	**14,770**	**15,403**	**15,405**	**15,737**	**15,737**	**15,743**	**15,744**	**15,744**	**15,744**	**15,744**	**15,744**	**15,055**
1	As modeled by GPC	14,770	15,341	15,343	15,706	15,706	14,702	14,703	14,703	14,703	14,703	14,703	14,013
2	Hydro Modernization Adjustment	0	0	0	31	31	31	31	31	31	31	31	31
3	Mossy Branch Availability (2025-2026)	0	62	62	0	0	0	0	0	0	0	0	0
4	Staff assumed extensions Scherer and Gaston	0	0	0	0	0	1,011	1,011	1,011	1,011	1,011	1,011	1,011
line	**Proposed Resource Capacity (MW)**	**239**	**239**	**750**	**980**	**980**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
5	GPC Proposed MPC PPA less Sale	239	239	750	750	750	0	0	0	0	0	0	0
6	GPC Proposed Santa Rosa PPA	0	0	0	230	230	0	0	0	0	0	0	0
7	GPC Proposed Robins BESS	0	0	0	0	0	0	0	0	0	0	0	0
8	GPC Proposed Moody BESS	0	0	0	0	0	0	0	0	0	0	0	0
9	GPC Proposed Co-located Solar + BESS	0	0	0	0	0	0	0	0	0	0	0	0
10	GPC Proposed Yates 8-10	0	0	0	0	0	0	0	0	0	0	0	0
11	GPC Proposed Remaining 1000 MW BESS	0	0	0	0	0	0	0	0	0	0	0	0
12	**Purchased Generating Capacity (MW)**	**4,535**	**5,159**	**5,237**	**5,321**	**5,576**	**5,905**	**5,905**	**3,886**	**3,924**	**3,906**	**3,940**	**2,661**
13	Existing Contracts	4,535	5,149	5,222	5,222	5,478	5,178	5,178	3,124	3,124	3,069	3,066	1,749
14	2022 IRP Planned Renewable	0	10	15	98	98	252	252	287	325	362	400	437
15	2022 IRP Planned ESS	0	0	0	0	0	475	475	475	475	475	475	475
16	**Dispatchable DSOs (MW)**	**675**	**696**	**716**	**758**	**805**	**750**	**752**	**750**	**749**	**749**	**749**	**749**
17	Existing Programs (CVR, DPEC, RTP, TempCheck)	675	675	669	669	657	602	604	602	601	601	601	601
18	DER Customer Program	0	21	47	89	148	148	148	148	148	148	148	148
19	Staff Assumed Additional Demand Response												
20	**Total Capacity (MW)**	**20,219**	**21,497**	**22,108**	**22,796**	**23,098**	**22,398**	**22,401**	**20,381**	**20,417**	**20,400**	**20,433**	**18,465**
21	**Winter Peak Demand Forecasts**												
22	Uniform w/Delays P95	15,202	15,513	16,041	17,699	18,470	19,084	19,768	20,375	20,666	20,888	21,040	21,145
23	**Winter Target Reserve Margin (Staff)**	22.94%	22.94%	22.94%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%
24	**Capacity Required to Meet Target (MW)**												
25	Uniform w/Delays P95	(1,530)	(2,425)	(2,387)	(935)	(285)	**1,173**	**2,015**	**4,786**	**5,109**	**5,400**	**5,555**	**7,653**

Staff Illustrative (Uniform with Delays P80)

Table C	Year	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
line	**Owned Generating Capacity (MW))**	**14,770**	**15,403**	**15,405**	**15,737**	**15,737**	**15,743**	**15,744**	**15,744**	**15,744**	**15,744**	**15,744**	**15,055**
1	As modeled by GPC	14,770	15,341	15,343	15,706	15,706	14,702	14,703	14,703	14,703	14,703	14,703	14,013
2	Hydro Modernization Adjustment	0	0	0	31	31	31	31	31	31	31	31	31
3	Mossy Branch Availability (2025-2026)	0	62	62	0	0	0	0	0	0	0	0	0
4	Staff assumed extensions Scherer and Gaston	0	0	0	0	0	1,011	1,011	1,011	1,011	1,011	1,011	1,011
line	**Proposed Resource Capacity (MW)**	**239**	**239**	**750**	**750**	**750**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
5	GPC Proposed MPC PPA less Sale	239	239	750	750	750	0	0	0	0	0	0	0
6	GPC Proposed Santa Rosa PPA	0	0	0	0	0	0	0	0	0	0	0	0
7	GPC Proposed Robins BESS	0	0	0	0	0	0	0	0	0	0	0	0
8	GPC Proposed Moody BESS	0	0	0	0	0	0	0	0	0	0	0	0
9	GPC Proposed Co-located Solar + BESS	0	0	0	0	0	0	0	0	0	0	0	0
10	GPC Proposed Yates 8-10	0	0	0	0	0	0	0	0	0	0	0	0
11	GPC Proposed Remaining 1000 MW BESS	0	0	0	0	0	0	0	0	0	0	0	0
12	**Purchased Generating Capacity (MW)**	**4,535**	**5,159**	**5,237**	**5,321**	**5,576**	**5,905**	**5,905**	**3,886**	**3,924**	**3,906**	**3,940**	**2,661**
13	Existing Contracts	4,535	5,149	5,222	5,222	5,478	5,178	5,178	3,124	3,124	3,069	3,066	1,749
14	2022 IRP Planned Renewable	0	10	15	98	98	252	252	287	325	362	400	437
15	2022 IRP Planned ESS	0	0	0	0	0	475	475	475	475	475	475	475
16	**Dispatchable DSOs (MW)**	**675**	**696**	**716**	**758**	**805**	**750**	**752**	**750**	**749**	**749**	**749**	**749**
17	Existing Programs (CVR, DPEC, RTP, TempCheck)	675	675	669	669	657	602	604	602	601	601	601	601
18	DER Customer Program	0	21	47	89	148	148	148	148	148	148	148	148
19	Staff Assumed Additional Demand Response												
20	**Total Capacity (MW)**	**20,219**	**21,497**	**22,108**	**22,566**	**22,868**	**22,398**	**22,401**	**20,381**	**20,417**	**20,400**	**20,433**	**18,465**
21	**Winter Peak Demand Forecasts**												
22	Uniform w/Delays P80	15,167	15,420	15,792	17,315	17,990	18,504	19,095	19,627	19,897	20,109	20,257	20,359
23	**Winter Target Reserve Margin (Staff)**	22.94%	22.94%	22.94%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%	23.52%
24	**Capacity Required to Meet Target (MW)**												
25	Uniform w/Delays P80	(1,573)	(2,539)	(2,693)	(1,180)	(648)	**456**	**1,184**	**3,862**	**4,158**	**4,438**	**4,587**	**6,681**

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Combustion Turbine Frame											
	GPC 2023 IRP Update	GPC 2022 IRP	Duke 2023 IRP	Santee Cooper 2023 IRP		DESC 2023 IRP		1803 2023 IRP Frame	EIA AEO 2023 Frame	NREL ATB 2023 Mod F-Frame	Entergy 2023 IRP CT (M501JAC)
				(H-Class)	(F-Class)	Frame 1x	Frame 2x				
Dollars			2023	2022	2022	2022	2022	2022	2022	2022	2022
Capacity (MW)			425	402	230	262	523	237	237	233	365
Capital Cost ($/kW)			750-900	699	744	1,402	1,154	782	867	1,069	925
Fixed O&M ($/kW-yr.)				4.8	7.7			7.92	7.88	25.59	6.66
Variable O&M ($/MWh)				11.42	8.53			5.09	5.06	6.92	14.74
Average Heat Rate (MBTU/MWh)			9,270	9,160	10,021			9,905	9,905	9,717	9,165

Combined Cycle 1x1										
	GPC 2023 IRP Update	GPC 2022 IRP	Santee Cooper 2023 IRP		DESC 2023 IRP (1x1)	1803 2023 IRP 1x1	EIA AEO 2023 (Single-Shaft 1x1x1)	Lazard 2023 LCOE (Low) (New Build)	Lazard 2023 LCOE (High) (New Build)	Entergy 2023 IRP Data Filing (1x1)
			1x1 7HA.03 w/ACC	1x1 7FA.05 w/ACC						
Dollars			2022	2022	2022	2022	2022	2022	2022	2022
Capacity (MW)			630	357	650	418	418	550	550	525
Capital Cost ($/kW)			1,103	1,702	1,452	1,204	1,330	650	1,300	1,156
Fixed O&M ($/kW-yr.)			7.31	11.05		15.94	15.87	10.00	17.00	18.43
Variable O&M ($/MWh)			2.68	3.11		2.88	2.87	2.75	5.00	3.47
Average Heat Rate (MBTU/MWh)			6,136	6,668		6,431	6,431	6,150	6,900	6,375

Onshore Wind											
	GPC 2023 IRP Update	GPC 2022 IRP	Duke 2023 IRP	Santee Cooper 2023 IRP	DESC 2023 IRP	EIA AEO 2023	NREL ATB 2023 (Mod)	Entergy 2023 IRP Data Filing	1803 2023 IRP	Lazard 2023 LCOE (Low)	Lazard 2023 LCOE (High)
Dollars	[redacted]		2023	2022	2022	2022	2022	2022	2022	2022	2022
Capacity (MW)			800	100	100	400	1,000	600	50	1,000	1,000
Capital Cost ($/kW)			4,150-4,850	3,952	4,323	6,672	2,572	3,620	2,618	3,000	5,000
Fixed O&M ($/kW-yr.)				118.73		123.81	112.09	76.95	117.68	60.00	80.00

Solar											
	GPC 2023 IRP Update	GPC 2022 IRP	Duke 2023 IRP	Santee Cooper 2023 IRP	DESC 2023 IRP	EIA AEO 2023	NREL ATB 2023 (Mod)	Entergy 2023 IRP Data Filing	1803 2023 IRP	Lazard 2023 LCOE (Low)	Lazard 2023 LCOE (High)
Dollars	[redacted]		2023	2022	2022	2022	2022	2022	2022	2022	2022
Capacity (MW)			75	100	75	150	100	100	50	150	150
Capital Cost ($/kW)			1,850	1,402	1,240	1,448	1,381	1,063	1,256	700	1,400
Fixed O&M ($/kW-yr.)				22.24		17.16	23.11	10.52	22.76	7.00	14.00

Battery Storage									
	GPC 2023 IRP Update (4 Hour)	GPC 2022 IRP	Duke 2023 IRP (4 Hour)	Santee Cooper 2023 IRP (4 Hour)	DESC 2023 IRP (4 Hour)	EIA AEO2023 (4 Hour)	NREL ATB 2023 (Mod) (4 Hour)	Entergy 2023 IRP (4 Hour)	1803 2023 IRP
Dollars			2023	2022	2022	2022	2022	2022	2022
Capacity (MW)			100	100	100	50	60	50/200	50
Capital Cost ($/kW)			2,250	1,757	1,459	1,270	1,844	1,171	1,593
Fixed O&M ($/kW-yr.)				43.92		45.75	46.10	13.39	39.85

Nuclear (Small Modular Reactor)									
	GPC 2023 IRP Update	Duke 2023 IRP	Santee Cooper 2023 IRP 12x60 MW	DESC 2023 IRP	EIA AEO2023	NREL ATB 2023 (Mod)	1803 2023 IRP	Lazard 2023 LCOE (Low) (New Build)	Lazard 2023 LCOE (High) (New Build)
Dollars		2023	2022	2022	2022	2022	2022	2022	2022
Capacity (MW)		300	683	274	600		600	2,200	2,200
Capital Cost ($/kW)		6,450	5,986	12,354	7,590	7,493	7,892	8,475	13,925
Fixed O&M ($/kW-yr)			95.50		106.92	163.53	107.43	131.50	152.75
Variable O&M ($/MWh)			11.65		3.38	2.66	3.39	4.25	5.00
Average Heat Rate (MBTU/MWh)		10,551	10,900		10,447	10,447	10,443	10,450	10,450

Medium Duration Energy Storage System	
	GPC 2023 IRP Update
Dollars	[redacted]
Capacity (MW)	
Capital Cost ($/kW)	
Fixed O&M ($/kW-yr)	
Variable O&M ($/MWh)	

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Staff Ranking Analysis						
		NPV ($000)	Cost (Savings)	Winter MW	NPV $/kW	Drop
Round 1	**ALL ON (BASE)**	[redacted]	[redacted]		[redacted]	
	REMOVE COLOCATED SOLAR+BESS			200		
	REMOVE MOODY			45		
	REMOVE ROBINS			115		
	REMOVE SANTA ROSA			230		
	REMOVE YATES			1,070		x
Round 2	**REMOVE YATES (BASE)**					
	REMOVE COLOCATED SOLAR+BESS			200		x
	REMOVE MOODY			45		
	REMOVE ROBINS			115		
	REMOVE SANTA ROSA			230		
Round 3	**REMOVE COLOCATED SOLAR+BESS (BASE)**					
	REMOVE MOODY			45		x
	REMOVE ROBINS			115		
	REMOVE SANTA ROSA			230		
Round 4	**REMOVE MOODY (BASE)**					
	REMOVE ROBINS			115		x
	REMOVE SANTA ROSA			230		