

May 2, 2025

**VIA ELECTRONIC DELIVERY**

Ms. Sallie Tanner  
Executive Secretary  
Georgia Public Service Commission  
244 Washington Street, SW  
Atlanta, Georgia 30334

**Re: Direct Testimony on Behalf of Georgia Interfaith Power & Light and Southface  
Energy Institute; Docket No. 56002, 56003**

Dear Ms. Tanner:

Please find enclosed an electronic version of the following **Direct Testimony of Chelsea  
Hotaling on behalf of Georgia Interfaith Power & Light and Southface Energy Institute** to  
be filed in Docket No. 56002 and 56003.

Please also find enclosed an electronic version of the Trade Secret version of the Direct  
Testimony of Chelsea Hotaling on behalf of GIPL and Southface.

Respectfully submitted,



Bob Sherrier  
Staff Attorney  
Southern Environmental Law Center  
Ten 10<sup>th</sup> Street NW, Suite 1050  
Atlanta, Georgia 30309  
678-686-8487  
bsherrier@selc.org

*Counsel for GIPL and Southface*

**STATE OF GEORGIA  
BEFORE THE  
PUBLIC SERVICE COMMISSION**

---

<b>In Re:</b>	)	
	)	<b>Docket No. 56002</b>
<b>Georgia Power Company’s</b>	)	
<b>2025 Integrated Resource Plan</b>	)	
	)	
<b>And</b>	)	
	)	
<b>Georgia Power Company’s 2025</b>	)	
<b>Application for the Certification,</b>	)	<b>Docket No. 56003</b>
<b>Decertification, and Amended Demand-</b>	)	
<b>Side Management Plan</b>	)	

---

**DIRECT TESTIMONY OF CHELSEA HOTALING  
ON BEHALF OF  
GEORGIA INTERFAITH POWER & LIGHT  
AND SOUTHFACE ENERGY INSTITUTE  
May 2, 2025**

## TABLE OF CONTENTS

<b>I. INTRODUCTION .....</b>	<b>1</b>
<b>II. SUMMARY OF RECOMMENDATIONS.....</b>	<b>2</b>
<b>III. GEORGIA POWER’S LARGE LOAD FORECAST .....</b>	<b>3</b>
A.    GEORGIA POWER DID NOT UPDATE ITS LARGE LOAD MODEL TO REFLECT ITS NEW DATA. ....	5
B.    DATA DEMONSTRATES GEORGIA POWER’S GROWTH ASSUMPTIONS ARE INACCURATE. ....	9
1. <i>Delay Data: GPC is underestimating project delays.</i> .....	9
2. <i>Ramp Rates: Georgia Power’s assumption that “ramp rates” are known variables is undermined by 2024 data.</i> .....	10
3. <i>Dropout Rates: Georgia Power’s data reflects high rates of dropout from the queue, which are not reflected in its modeling assumptions.</i> .....	12
C.    GEORGIA POWER’S RELIANCE ON INACCURATE ASSUMPTIONS HAS LED TO AN OVERSTATEMENT OF ITS LOAD FORECAST. ....	15
1. <i>Dropout Risk: Georgia Power’s model does not reflect the risk of prospective customers (without a contract) dropping out of the pipeline.</i> .....	15
2. <i>Bifurcated Load Model: Georgia Power should develop two distinct load forecast projections.</i> .....	19
3. <i>Project Delay Risk: Georgia Power understates the length of delay that its prospective customers are likely to encounter.</i> .....	20
4. <i>New assumptions significantly impact load growth sensitivities.</i> .....	22
5. <i>Additional concerns not captured in load growth sensitivities above: load ramp &amp; materialization rates.</i> .....	23
D.    RECOMMENDATIONS .....	28
<b>IV. RESERVE MARGIN STUDY .....</b>	<b>29</b>
<b>V. THE RESOURCE MIX STUDY .....</b>	<b>38</b>
A.    ALTERNATIVE MODELING RUNS: I TESTED THE IMPACT OF 5 SENSITIVITIES ON THE ECONOMICALLY OPTIMAL RESOURCE MIX RECOMMENDED BY AURORA. ....	39
B.    IN ADDITION TO THE LIMITED VARIABLES I TESTED, ADDITIONAL MODELING ASSUMPTIONS SHOULD BE REEVALUATED. ....	46
1. <i>Georgia Power instructed its model not to choose more than 1,500 MW of solar per year.</i> .....	46
2. <i>Georgia Power’s cost assumptions for thermal resources are too low.</i> .....	47
C.    ALTERNATIVE MODELING RUNS: RESOURCE MIX RESULTS .....	50
D.    ALTERNATIVE MODELING RUNS: PRESENT VALUE OF REVENUE REQUIREMENTS RESULTS.....	52
E.    COAL RETIREMENTS: MORE RELIABLE INFORMATION IS NEEDED TO IDENTIFY THE MOST ECONOMICALLY OPTIMAL PATH FORWARD. ....	55
<b>VI. CONCLUSION .....</b>	<b>58</b>

**I. INTRODUCTION**

**Q: PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.**

A: My name is Chelsea Hotaling. I am a Senior Consultant at Energy Futures Group (“EFG”), located at 90 Main Street, Canton, New York, 13617.

**Q: MS. HOTALING, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.**

A: I have worked for eight years in electric utility regulation and related fields. I have reviewed dozens of integrated resource plans (“IRPs”) and related filings by utilities in Arizona, Colorado, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Montana, New Mexico, Nova Scotia, Puerto Rico, South Carolina, and Wisconsin. I have performed my own capacity expansion, production cost, and reliability modeling in numerous cases using multiple models including EnCompass, AURORA, PLEXOS, and the Strategic Energy & Risk Valuation Model (“SERVM”).

I received a Bachelor’s Degree in Accounting and Economics from Elmira College in 2011. I also received a Master of Business Administration Degree in 2012, a Master’s Degree in Environmental Policy in 2019, and a Master’s Degree in Data Analytics in 2020, from Clarkson University. My curriculum vitae, included as **Exhibit CH-1**, provides additional detail regarding my professional and educational experience.

**Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION?**

A. Yes, I testified before the Georgia Public Service Commission in Georgia Power’s 2023 IRP Update, Docket No. 55378.

**Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?**

A: I am testifying on behalf of Georgia Interfaith Power and Light (“GIPL”) and Southface Energy Institute (“Southface”).

**Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A: I was asked to review the assumptions and recommendations Georgia Power Company (“GPC” or “Georgia Power”) made in its 2025 IRP with respect to the large load forecast, the SERVVM modeling used to develop the target reserve margin (“TRM”), and Georgia Power’s proposed pathway for meeting projected load growth.

## **II. SUMMARY OF RECOMMENDATIONS**

**Q: PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS.**

A: My key findings and recommendations are as follows:

### **1. Load Forecast**

- a. Georgia Power has not updated its large load forecast assumptions to reflect data it has collected since the 2023 IRP, despite the new data undermining the reliability of assumptions in its model.
  - i. Importantly, Georgia Power’s large load forecast model does not incorporate the risk of prospective customers without signed contracts dropping out of the pipeline. In order to capture this risk, Georgia Power should utilize data on the historical dropout rate for these prospective customers.
- b. Georgia Power’s load forecast is overstated. When I made selected modifications to Georgia Power’s input assumptions to reflect the actual data collected by Georgia Power, the results indicated these changes have a significant impact on the projected load growth for Georgia Power.
- c. The Commission should not use Georgia Power’s 2025 IRP large load forecast for resource planning. Instead, the Commission should direct Georgia Power to submit a revised large load forecast with updated inputs and assumptions to reflect its actual data. In addition, the Commission should direct Georgia Power to project growth for its “committed” customers. Georgia Power’s projected growth potential based on prospective, non-committed customers should be provided to the

Commission as an additional layer of information to inform the Commission's policy determinations.

## **2. Reserve Margin Study**

- a. The Commission should order Georgia Power to modify its approach to modeling new large load customers in SERVIM to ensure that those loads are not scaled based on weather and do not have load forecast errors applied to them within the reserve margin study.

## **3. Resource Mix Study**

- a. The Commission should order Georgia Power to update its load projections and resource mix model for at least MG0 and MG0-111:
  1. Using available load growth data to identify more reasonable assumptions; and
  2. Using cost comparison data from the pending all-source RFP to reflect critical resource cost assumptions in its resource mix.

## **III. GEORGIA POWER'S LARGE LOAD FORECAST**

**Q: HOW DID GEORGIA POWER DEVELOP ITS FORECAST FOR NEW LARGE LOAD CUSTOMERS FOR THE 2025 IRP?**

**A:** Georgia Power used the same load forecasting methodology and model that was introduced in the 2023 IRP.

**Q: CAN YOU EXPLAIN WHY GEORGIA POWER DEVELOPED ITS OWN MODEL FOR FORECASTING NEW LARGE LOAD CUSTOMERS?**

**A:** The level of new large load<sup>1</sup> growth resulted in a significant difference in the load growth projection between the 2022 and 2023 IRP. The traditional methods of forecasting load growth rely on economic and demographic variables as drivers of energy use. Since these

---

<sup>1</sup> See Georgia Power 2025 Integrated Resource Plan ("2025 IRP Main Document") at 35, fn. 26 (Georgia Power's definition of large load states, "In general, for purposes of forecasting and planning for large load customers, the Company defines 'large load' to be industrial load greater than or equal to 45 MW and commercial load greater than or equal to 115 MW.").

1 models are based on the historical trends for the different variables included in the model,  
2 it is challenging for the traditional forecast to be able to account for the large load (Georgia  
3 Power also refers to as “economic development projects”) arising from the demand growth  
4 Georgia is experiencing. As a result, Georgia Power developed its own model for  
5 forecasting load growth from new large load customers, which Georgia Power refers to as  
6 the load realization model (“LRM”).<sup>2</sup>

7 **Q: CAN YOU EXPLAIN HOW THE LOAD REALIZATION MODEL IS**  
8 **CONFIGURED TO FORECAST THE NEW LARGE LOAD CUSTOMERS?**

9 A: Yes. Georgia Power’s description of the configuration of the model has not changed since  
10 the 2023 IRP Update. A description of the basics of the model is attached as Exhibit CH-  
11 2. However, my analysis revealed a significant discrepancy between Georgia Power’s  
12 model and the 2025 IRP model outputs. This discrepancy suggests Georgia Power has  
13 adjusted its large load projections from the model output, without describing publicly this  
14 step of its process. This unexplained adjustment is described further at page 13.

15 **Q: DID YOU REVIEW GEORGIA POWER’S PROCESS FOR DEVELOPING**  
16 **ASSUMPTIONS FOR NEW LARGE LOAD CUSTOMERS, OR THE LOAD**  
17 **REALIZATION MODEL, AS PART OF THE 2023 IRP?**

18 A: Yes, I reviewed the 2023 IRP load realization model and the probabilities Georgia Power  
19 assigned to the uncertain variables specified in the model.

20 **Q: WHEN YOU REVIEWED THE LOAD REALIZATION MODEL AT THE TIME**  
21 **OF THE 2023 IRP, DID YOU MAKE ANY RECOMMENDATIONS?**

22 A: Yes. I recommended that Georgia Power use the 50<sup>th</sup> percentile, or P50, for its large load  
23 model adjustment value. At that time, Georgia Power was using the 95<sup>th</sup> percentile, or P95,  
24 for its large load model adjustment value, and I did not believe it was reasonable to plan  
25 for a load scenario that was at or higher than 95% of modeling scenarios identified by the  
26 model. I provided several reasons to support the P50 level, but one of the main reasons is  
27 that using the most likely value (P50) aligns with the approach used for developing load

---

<sup>2</sup> The load forecast model is referred to as the “load realization model” in the workpapers provided by Georgia Power with this filing.

1 forecasts for utility planning. Load forecasts that utilities use as inputs for capacity  
2 expansion models are typically 50/50 forecasts, which means there is a 50% chance of an  
3 over-forecast (meaning the forecast is higher than actual needs) and a 50% chance of an  
4 under-forecast (meaning the forecast is lower than actual needs).

5 I also made a recommendation for Georgia Power to track customer data. The 2023 IRP  
6 was the first time Georgia Power introduced the load realization model. Given the lack of  
7 historical data for large load customers at the scale they appeared in the model, I testified  
8 that granular data tracking was critical to help inform what values to include for the  
9 uncertain variables in the load realization model. At that time, there was no data to  
10 benchmark the assumptions Georgia Power made for each probability included in the  
11 model.

12 **Q: DID GEORGIA POWER CONTINUE TO USE THE 95<sup>TH</sup> PERCENTILE FROM**  
13 **THE LOAD REALIZATION MODEL FOR THE 2025 IRP?**

14 A: No. Georgia Power has modified its new large load forecast to include the 50<sup>th</sup> percentile  
15 from the load realization model. This is a significant improvement from the 2023 IRP.

16 **Q: HAS GEORGIA POWER BEEN TRACKING DATA REGARDING ITS LARGE**  
17 **LOAD GROWTH SINCE THE 2023 IRP?**

18 A: Yes. Georgia Power has been filing quarterly reports reflecting the growth in the large load  
19 pipeline, as well as providing important data metrics concerning the changes to that growth.  
20 This is another significant improvement from the 2023 IRP.

21 **Georgia Power did not update its large load model to reflect its new data.**

22 **Q: HAS GEORGIA POWER USED ITS NEW DATA TO INFORM THE**  
23 **UNCERTAIN VARIABLES USED IN ITS LARGE LOAD MODEL?**

24 A. No. Georgia Power has not used new data on large loads to update its assumptions about  
25 how large load customers will behave.<sup>3</sup>

---

<sup>3</sup> 2025 Direct Hr'g Tr. 519:15-17.



1 **Q: WHAT IS YOUR BASIS FOR BELIEVING THAT GEORGIA POWER DID NOT**  
2 **USE ITS AVAILABLE DATA IN ITS LOAD REALIZATION MODEL?**

3 A: Georgia Power testified that it has not updated the probabilities used in its large load model  
4 since it originally developed the large load model, prior to the 2023 IRP Update. Georgia  
5 Power testified that it is “exploring some refinements of certain probabilities, and [it] may  
6 suggest to make those refinements going forward.”<sup>4</sup> But despite having two full quarters  
7 of Commission-ordered data<sup>5</sup> at its disposal, and additional information from the 2023 IRP,  
8 at the time of developing this load forecast, Georgia Power failed to account for that data  
9 in its estimates.<sup>6</sup> Further, Georgia Power has indicated that it does not plan to supplement  
10 its analysis during this docket.<sup>7</sup>

11 **Q: SHOULD GEORGIA POWER HAVE UPDATED ITS LARGE LOAD MODEL**  
12 **USING AVAILABLE DATA?**

13 A: Yes. Georgia Power testified that it is “commit[ed] . . . to be rigorous . . . to incorporate the  
14 latest available information every time that we develop a forecast.”<sup>8</sup> I agree that this  
15 approach to updating is necessary. But Georgia Power did not follow this approach with  
16 respect to its large load model in this IRP. It is unreasonable not to at least test Georgia  
17 Power’s assumptions with the available data. The reliability of the modeling used by  
18 Georgia Power depends on the reliability of the assumptions fed into the model. If Georgia  
19 Power is not utilizing recent data about the assumptions for the model, then the model will  
20 not reflect how those loads are materializing.

21 For this docket, by the time the load forecast was developed, Georgia Power had at least  
22 three quarters of granular load information—two of which had been published (in part) as  
23 required by this Commission. By the time Georgia Power testified in this case, Georgia  
24 Power had at least five quarters of granular load information. That is not only the best data

---

<sup>4</sup> 2025 Direct Hr’g Tr. 520:20-22.

<sup>5</sup> Georgia Power files quarterly Large Load Economic Development Reports in Docket No. 55378.

<sup>6</sup> Georgia Power response to STF-DEA-1-44.

<sup>7</sup> 2025 Direct Hr’g Tr. 489:9-11.

<sup>8</sup> 2025 Direct Hr’g Tr. 659:24-660:2.

1 available to Georgia Power: It is the only Georgia Power-specific quantitative data  
2 available to test the assumptions upon which the entire model relies.

3 **Q: IF THE DATA INPUTS RELIED ON BY GEORGIA POWER HAVE NOT**  
4 **CHANGED SINCE THE 2023 IRP, WHY HAVE YOUR CRITIQUES OF THOSE**  
5 **INPUTS CHANGED?**

6 A: The model is only as good as its inputs. During the 2023 IRP, Georgia Power repeatedly  
7 explained that it was relying on “informed judgment within the Company to develop key  
8 assumptions” because there was “no historical data that can serve as a guide.”<sup>9</sup> That is no  
9 longer the case. While it is true that the data available is limited, the available data still has  
10 considerable value.

11 **Q: CAN YOU SHARE SOME HIGHLIGHTS FROM YOUR REVIEW OF THE DATA**  
12 **FROM EACH OF THE QUARTERLY LOAD REPORTS SUBMITTED BY**  
13 **GEORGIA POWER?**

14 A: **Table 1** provides the changes observed between the first quarterly report submitted by  
15 Georgia Power through the fourth quarterly report.<sup>10</sup> “Load Change” reflects the aggregate  
16 change in the customer’s projection for its announced load. This represents customers  
17 making modifications to their announced load, whether that is an increase or decrease.  
18 When looking across the four quarterly reports, there has been a downward adjustment for  
19 the load announced by customers, with the exception of quarter three. “Load Removed”  
20 reflects the level of load that has left Georgia Power’s load queue. There was a significant  
21 drop between the 2023 IRP model and the first quarterly report, and some level of load has  
22 left the queue across each report. “Initial Service Change” reflects the number of customers  
23 that made a change to their requested online date. “Load Ramp Change” reflects the  
24 number of customers that modified their projected load ramp.

---

<sup>9</sup> See, e.g., Georgia Power responses to STF-DEA-1-8 (PD), *attached as* CH-Exhibit 4 and STF-DEA-1-9 (PD) (Docket 55378), *attached as* CH-Exhibit 5.

<sup>10</sup> The “Q1” column reflects changes from the 2023 IRP model through the first quarterly report. The “Q2” column reflects changes from the first quarterly report to the second quarterly report. The “Q3” column reflects changes from the second quarterly report to the third quarterly report. The “Q4” column reflects changes from the third quarterly report to the fourth quarterly report.

	Q1	Q2	Q3	Q4
<b>“Announced” Load Change</b>	-204 MW	-581 MW	134 MW	-957 MW
<b>Load Removed</b>	-5,983 MW	-2,595 MW	-2,835 MW	-1,698 MW
<b>Load Added</b>	9,906 MW	6,359 MW	14,734 MW	12,203 MW
<b>Initial Service Change</b> (# of customers)	17	23	50	21
<b>Load Ramp Change</b> (# of customers)	15	25	23	13

**Table 1. Changes in Quarterly Load Reports<sup>11</sup>**

**Q: DO THE QUARTERLY LOAD REPORTS SUBMITTED BY GEORGIA POWER ALSO PROVIDE INFORMATION ON THE NUMBER OF CUSTOMERS THAT GEORGIA POWER CONSIDERS TO BE COMMITTED?**

**A:** Yes, the reports provide information on the “Project Stage”, which indicate whether there is a signed contract, a request for service (“RFS”), or if customers are under what Georgia Power refers to as technical review. Georgia Power considers committed customers to be those customers who have at least executed a request for service from Georgia Power.<sup>12</sup> Georgia Power considers prospective customers, or those under technical review, as customers that have not signed a RFS with the company.<sup>13</sup>

**Q: WHAT DID YOUR REVIEW OF THE QUARTERLY LOAD REPORTS INDICATE ABOUT THE LEVEL OF COMMITTED AND PROSPECTIVE CUSTOMERS?**

**A:** **Table 2** shows a comparison of committed customers (those with a signed contract or request for service) and prospective (customers under technical review) across the four quarterly load reports submitted by Georgia Power.

<sup>11</sup> Calculated from data provided in the Quarterly Load Reports submitted by Georgia Power.

<sup>12</sup> 2025 IRP Main Document at 36, fn. 27.

<sup>13</sup> Georgia Power response to STF-DEA-1-4.

	Q1	Q2	Q3	Q4
<b>Contract</b>	2,834 (14.5%)	3,446 (15.1%)	3,571 (10.3%)	3,811 (8.7%)
<b>Request for Service</b>	3,353 (17.1%)	3,806 (16.7%)	4,475 (12.9%)	4,031 (9.2%)
<b>Technical Review</b>	13,393 (68.4%)	15,511 (68.1%)	26,586 (76.8%)	35,906 (82.1%)
<b>Total</b>	19,580 (100%)	22,763 (100%)	34,632 (100%)	43,748 (100%)

**Table 2. Level of Committed and Prospective Customers (MW)**

Customers with a contract have entered into an agreement with Georgia Power to receive service. Customers with a signed request for service have signed an agreement that if they choose to locate in Georgia, then they will select Georgia Power as their electric service provider. Customers in Technical Review do not appear to have any required financial commitment to Georgia Power. As **Table 2** indicates, there has been movement in the number of customers going from technical review to request for service, and customers moving from request for service to the contract stage, but the vast majority of the load pipeline are customers Georgia Power classifies as under technical review.

**Data demonstrates Georgia Power's growth assumptions are inaccurate.**

**Q: AT THE TIME THE LARGE LOAD MODEL WAS CREATED, WAS THERE ANY REASON FOR GEORGIA POWER TO BELIEVE THAT GEORGIA POWER'S ASSUMPTIONS WERE INACCURATE?**

A: Yes. As explained in more detail below, the data Georgia Power provides in the large load economic development reports ("quarterly reports") suggests some of Georgia Power's assumptions are too aggressive, which would cause load projections to be too high. There are several examples.

1. Delay Data: GPC is underestimating project delays.

For example, data from the second quarterly report<sup>14</sup> reflects that customers' commercial operation date is likely to be significantly more delayed than Georgia Power assumes in its model. Georgia Power's modeling assumptions "are based on the Company's estimates," not quantitative data.<sup>15</sup>

**Table 3** shows the project delay data through the second quarterly report across all customer segments (first row) and then for the customer segments that had more than three data points, which include [REDACTED]

[REDACTED] In comparison to the values Georgia Power assumed, which are reflected in the last line of the below Table 3, these data-driven values indicate substantially longer maximum delays and a longer most likely delay for the [REDACTED] customer segment.

Customer Segment	Minimum <sup>16</sup>	Most Likely (Months)	Maximum
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
[REDACTED]	[REDACTED]	[REDACTED]	[REDACTED]
All	[REDACTED]	[REDACTED]	[REDACTED]
GPC Model Assumption	[REDACTED]	[REDACTED]	[REDACTED]

**Table 3. Project Delay Reported in Q1 and Q2 Large Load Reports**

2. Ramp Rates: Georgia Power's assumption that "ramp rates" are known variables is undermined by 2024 data.

The load realization model includes a projected ramp rate for each customer within the model. Georgia Power treats the "ramp-up" schedule as a "known project input" provided by the customer.<sup>17</sup> And it does not model that input for being uncertain.

Quarterly data reveals that the "ramp-up" schedule provided by customers is very uncertain, and that customers project—on average—a ramp-up of energy demand faster than actually required.

<sup>14</sup> Georgia Power "locked down all inputs related to modeling the large load customer forecast on June 30, 2024." Georgia Power response to STF-DEA-3-5 subpart b.

<sup>15</sup> 2025 Tech. Appx. 1, B2025 Load and Energy Forecast, 7.1.8 at 106.

<sup>16</sup> Although some project delays were actually reporting an earlier project date, negative values were set to be 0 for the minimum.

<sup>17</sup> 2025 Tech. Appx. 1, B2025 Load and Energy Forecast, 7.1.1-7.1.2 at 103.

**Table 4** and **Table 5** show the difference in ramp rates between the 2023 IRP and the first quarterly load report and then the first quarterly load report and the second quarterly load report, respectively. Both tables indicate a downward adjustment to the projected ramp rates for customers. Georgia Power's load realization model is only configured to reflect the probability of either the customer's announced load versus metered load or the initial service date changing. The assumptions related to the rate ramp are as given in the model. However, as the data reflects, downward adjustments are being reported for the ramp rates.

Year	2023 IRP	Q1	Difference
2024	254	146	-108
2025	1,209	760	-449
2026	2,058	1,459	-599
2027	2,607	1,915	-692
2028	2,985	2,492	-493
2029	3,308	2,903	-405
2030	3,689	3,224	-465
2031	3,958	3,399	-559
2032	4,144	3,545	-599
2033	4,221	3,706	-515
2034	4,293	3,835	-458
2035	4,360	3,935	-425
2036	4,392	3,967	-425
2037	4,392	4,188	-204

**Table 4. Ramp Rate Reported in First Quarterly Report**

Year	Q1	Q2	Difference
2024	268	157	-111
2025	1,356	639	-717
2026	3,313	1,923	-1,390
2027	4,751	3,879	-872
2028	6,807	6,007	-800
2029	7,950	7,557	-393
2030	8,776	8,365	-411
2031	8,963	8,669	-294
2032	9,046	8,756	-290
2033	9,118	8,842	-276
2034	9,190	8,929	-261
2035	9,257	8,929	-328
2036	9,289	8,929	-360
2037	9,510	8,929	-581

**Table 5. Ramp Rate Reported in Second Quarterly Report**

As I will discuss in more detail below, it appears Georgia Power made a downward adjustment to the load realization model. It is unclear whether this adjustment is intended to account for some of the differences seen in the data related to ramp rates or if there are other driver(s) for the adjustment.

3. Dropout Rates: Georgia Power's data reflects high rates of dropout from the queue, which are not reflected in its modeling assumptions.

The load realization model does not incorporate a risk of customers without a signed contract with Georgia Power dropping out of the queue.

Instead, Georgia Power's forecast assumes that it is almost certain that all of the data centers in its pipeline will end up operating their projects in Georgia.<sup>18</sup> These estimates are incompatible with the data available and with the market.

- Georgia Power estimates a 93% likelihood that all data centers in its pipeline in technical review (meaning, who have not yet signed a request for service with Georgia Power) will eventually sign a contract for service in Georgia. None of those projects are under construction.

<sup>18</sup> Georgia Power response to DEA-3-8 Attachment TS.

- Georgia Power estimates a 95% likelihood that all data centers in its pipeline that have signed a request for service or contract for service will, in fact, succeed as projects requiring energy on the system (i.e., will not cancel the project or go into bankruptcy).

A review of the data indicates that there is a substantial risk of these prospective customers dropping out of the queue. If this risk is not captured in the model, then it could lead to an over-projection for customers that have not entered into any agreements with Georgia Power. I will discuss this in more detail below.

**Q: HAVE YOU PROVIDED AN EXHAUSTIVE LIST OF THE WAYS IN WHICH GEORGIA POWER HAS FAILED TO USE THE BEST AVAILABLE DATA?**

A: No. I have provided examples to illustrate the difference between Georgia Power's modeling and its own data that it has made available at the direction of this Commission.

**Q: ARE THERE ANY OTHER REASONS FOR CONCERN ABOUT THE MODEL'S INPUTS?**

A: Yes. It appears that Georgia Power introduced a new step into the load realization model, which it has not publicly identified or defined. This step reduces the P50 level of projected load from the load realization model before it is incorporated into the load forecast modeled in AURORA for the resource mix study. I use the word appear when I describe this modification because Georgia Power has offered no explanation for why it has made this adjustment to the data. I was only able to identify this difference when I reran Georgia Power's load realization model through the @RISK software and produced results different from what was reported by Georgia Power.<sup>19</sup> **Table 6** shows the P50 load reported by Georgia Power and the results when I rerun the model that Georgia Power provided with its IRP workpapers. My rerun of the load realization model shows higher load projections than what Georgia Power has provided in its IRP filing. While it is unclear why Georgia Power implemented this step, I maintained this assumption of a discount for the alternative load forecasts I developed and discuss in more detail in my testimony.

---

<sup>19</sup> 2025 Tech. Appx. 1, TS-B2025 Load and Energy Forecast, Table 7.2.1 at 108.



**Q: WHY IT IS IMPORTANT TO UNDERSTAND THIS APPARENT ADJUSTMENT?**

A: It is important to understand why Georgia Power made this adjustment, particularly if it is to correct for differences observed in how load is materializing as compared to what is projected by the load realization model. If there is a gap between projections in the model and what Georgia Power is currently observing with these new large load customers, or for what Georgia Power expects to happen, then that is an indication that the model is not capturing something correctly or that model inputs need to be updated. Either way, it is another sign that the load realization model should be reevaluated for improvements.

Year	Reported by GPC (MW) <sup>20</sup>	Rerun of Model (MW) <sup>21</sup>	% Difference (GPC Reported v.CH Rerun)
2024			
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035			
2036			
2037			
2038			
2039			
2040			
2041			
2042			
2043			
2044			

**Table 6. Comparison of Results for the Load Realization Model**

<sup>20</sup> *Id.*

<sup>21</sup> My rerun of the load realization model is based on the Georgia Power workpaper named “Budget 2025 Load Realization Model TRADE SECRET”.

1 **Georgia Power's reliance on inaccurate assumptions has led to an overstatement of its**  
2 **load forecast.**

3 **Q: AFTER REVIEWING THE DATA FROM GEORGIA POWER'S QUARTERLY**  
4 **LOAD REPORTS, DID YOU TEST THE IMPACT OF MODIFYING INPUT**  
5 **ASSUMPTIONS ON GEORGIA POWER'S LOAD REALIZATION MODEL?**

6 A: Yes. I evaluated the impact of making three changes to the load realization model:

- 7 1. Introducing a new P1 probability, or P1A, to capture the risk of technical review  
8 customers dropping out of Georgia Power's load queue.
- 9 2. Splitting the forecast into one for only committed customers and one for committed  
10 customers plus technical review customers, with the inclusion of the new P1A  
11 probability.
- 12 3. Modifying the delay probability to reflect data from the four 2024 quarterly load  
13 reports.

14 I will discuss each of these changes in more detail below.

- 15 1. Dropout Risk: Georgia Power's model does not reflect the risk of prospective  
16 customers (without a contract) dropping out of the pipeline.

17 **Q: DO YOU BELIEVE GEORGIA POWER'S LOAD REALIZATION MODEL**  
18 **REFLECTS THE RISK OF PROSPECTIVE CUSTOMERS, OR THOSE**  
19 **DESIGNATED WITH A PROJECT STATUS OF TECHNICAL REVIEW,**  
20 **DROPPING OUT OF THE LOAD QUEUE?**

21 A: No, I do not.

22 **Q: WHY IS IT IMPORTANT FOR THE RISK OF TECHNICAL REVIEW**  
23 **CUSTOMERS DROPPING OUT OF THE QUEUE TO BE REFLECTED IN THE**  
24 **LOAD REALIZATION MODEL?**

25 A: If there is not an adjustment incorporated to reflect the risks around technical review  
26 customers dropping out of the queue, then the projected load for these prospective  
27 customers included in the load realization model will be too high. If there is an over-

1 projection of load, then there is the risk that Georgia Power will plan to procure capacity  
2 that may not be needed if the load does not materialize from the prospective customers.

3 **Q: IS IT YOUR UNDERSTANDING THAT GEORGIA POWER'S STANCE IS THAT**  
4 **P1 REFLECTS THIS RISK OF TECHNICAL REVIEW CUSTOMERS**  
5 **DROPPING OUT OF THE QUEUE?**

6 A: In his testimony on the stand, Witness Valle is asked where in the model it accounts for  
7 prospective customers dropping out of the pipeline, and he suggests that P1 (which  
8 estimates whether a customer will select the state of Georgia) captures this risk.<sup>22</sup>

9 Q: So the selecting state probability isn't just, are you going to  
10 select Georgia or another state? That is designed to incorporate,  
11 are you going to select Georgia or are you going to fail as a  
12 business or not materialize at all? Is that –

13 A: (Witness Valle) That is the decision that the model is trying  
14 to quantify, yes.

15 After reviewing the data, I am not sure how this can be. For example, data center developers  
16 who have not signed a contract with Georgia Power were assigned an almost certain  
17 (93%)<sup>23</sup> likelihood of choosing Georgia over other states. This is almost certainly too high  
18 to reflect the likelihood that data center developers will choose Georgia, and it is  
19 unreasonably high as a data point to reflect the likelihood that each data center development  
20 project will actually come to fruition. This probability cannot account for the probability  
21 of projects dropping out of the queue before they have a signed contract with Georgia  
22 Power, whether that be due to financial reasons, changes in plans, indefinite delay, etc.

23 **Q: WHAT WERE THE PROBABILITIES FOR THE TECHNICAL REVIEW**  
24 **CUSTOMERS IN GEORGIA POWER'S LOAD REALIZATION MODEL?**

25 A: **Table 7** shows the average P1, P2, P3, and probability product for the technical review  
26 customers in the load realization model used in the 2025 IRP.

---

<sup>22</sup> See 2025 Direct Hr'g Tr. 526:18-527:19.

<sup>23</sup> Georgia Power response to STF-DEA-3-8.

P1	P2	P3 <sup>24</sup>	Product
84%	42%	95%	35%

**Table 7. Average Probabilities for Technical Review Customers<sup>25</sup>**

Technical review customers accounted for 15,511 MW of the announced load in the model. If the probability product for each technical review customer is multiplied by the announced load for each project, that represents about 5,412 MW of new load for technical review customers. While that does represent a discount from the total announced pipeline, it does not capture the additional risk of technical review customers not proceeding with their prospective projects.

**Table 8** shows Georgia Power's reporting of the customers that dropped out of the 2023 IRP model. Out of the original 51 projects in the 2023 IRP model, 27 projects—over half—left the queue.<sup>26</sup>

Project Success Probability (P2)	Total Customers	Dropped	Drop Rate
25%	13	6	46%
50%	15	14	93%
75%	9	6	67%
100%	14	1	7%
<b>Total</b>	<b>51</b>	<b>27</b>	<b>53%</b>

**Table 8. 2023 IRP Model Customer Change<sup>27</sup>**

Based on the drop rate for each of the Project Success levels reported by Georgia Power, there is an even more significant risk (70% dropout) for projects that have been assigned anything other than a 100% Project Success Probability by Georgia Power.

**Q: HOW DO YOU PROPOSE THAT GEORGIA POWER UPDATE ITS LOAD REALIZATION MODEL TO REFLECT THE RISK OF CUSTOMERS WITH A TECHNICAL REVIEW PROJECT STATUS DROPPING OUT?**

**A:** I recommend that Georgia Power include a probability that I refer to as “P1A”. The idea is that this probability reflects the success rate for technical review customers not dropping

<sup>24</sup> The same value is assigned to each customer regardless of project status.

<sup>25</sup> Georgia Power response to STF-DEA-3-8.

<sup>26</sup> Georgia Power response to STF-DEA-1-43.

<sup>27</sup> *Id.*

1 out of the new large load queue. The P3 probability, or Georgia Power's probability for  
2 contract success, is included in the load realization model to reflect the success rate of a  
3 customer materializing after a contract with Georgia Power has been signed.<sup>28</sup> While this  
4 probability reflects the chance of customers dropping out of the model, even with a signed  
5 contract, the model does not reflect the probability of a customer leaving Georgia Power's  
6 load queue if they are considered in the technical review stage with no commitments. There  
7 were 46 technical review customers included in the second quarterly report, and based on  
8 the data provided by Georgia Power, none of them have a status of "Under Construction".<sup>29</sup>  
9 This is important to note as it highlights the concern around the level of commitment from  
10 technical review customers. Since the customers under technical review have not signed  
11 any contracts with Georgia Power, additional risk of these customers leaving the queue  
12 should be incorporated into the load realization model.

13 **Q: HOW CAN THE DATA FROM THE LARGE LOAD REPORTS BE USED TO**  
14 **DEVELOP PROBABILITY P1A?**

15 A: The data of customers dropping out of the load queue can be used to compare points in  
16 time. For example, if you start with the data from Q1, there were 41 technical review  
17 projects. If you track those projects through until the Q4 report, there were 12 projects that  
18 dropped out because they were "cancelled" or "indefinitely" delayed. There were an  
19 additional 4 projects that dropped out for choosing an "alternative state" and 3 other  
20 projects dropped out for other reasons. If you only consider those projects that dropped out  
21 as a result of being cancelled or delayed indefinitely, then the dropout rate for a technical  
22 review customer is 12/41 or 29%. When translated into a probability for success of a  
23 technical review customer remaining in the queue based on the data between the Q1 and  
24 Q2 large load reports, that would be 71%. This can then be included as P1A in the load  
25 realization model and applied to the technical review customers.

26 **Q: THE RECOMMENDATION YOU HAVE MADE AS IT RELATES TO P1A IS**  
27 **DEVELOPED FROM DATA THAT WAS NOT KNOWN AT THE TIME**

---

<sup>28</sup> Georgia Power response to STF-DEA-1-13. Docket No. 55378.

<sup>29</sup> Georgia Power response to STF-DEA-3-8.

1       **GEORGIA POWER DEVELOPED ITS LOAD FORECAST FOR THE IRP,**  
2       **WHICH WAS THE SECOND QUARTERLY REPORT. HOW COULD GEORGIA**  
3       **POWER HAVE INTEGRATED THIS RISK INTO ITS MODEL?**

4       A:     The calculation I provided illustrates an example of how the data can be used to develop  
5             an assumption around P1A. For Georgia Power, there was data available on the rate of  
6             projects dropping out of the load queue between the 2023 IRP model and the start of  
7             Georgia Power submitting the large load reports. This data is referenced in **Table** . I did  
8             not use these data points because I did not have information on the project status of those  
9             customers or the reasons each customer left the queue. (If the customers dropped out of the  
10            pipeline to operate in another state or to take service from another Georgia provider, those  
11            probabilities of dropout would presumably still be captured in the model. So it is important  
12            to understand why customers dropped out.) The information I am missing to do a more  
13            complete analysis is available to Georgia Power. In addition, the data in Table 7 strongly  
14            suggests that the dropout value I use (P1A) to demonstrate the sensitivity of dropout to the  
15            model is likely very conservative. With additional time, the dropout rate would be expected  
16            to increase.

17      **Q:     IS IT YOUR RECOMMENDATION THAT GEORGIA POWER MAINTAIN THE**  
18      **P1A PROBABILITY AT 71%?**

19      A:     No. My recommendation relates to the inclusion of a P1A probability that incorporates the  
20             risk of a technical review customer dropping out of the load queue. As it relates to the  
21             specific probability, my recommendation is for Georgia Power to use the data it is  
22             collecting for the quarterly load reports to develop the best approximation of dropout risk  
23             for technical customers for each iteration of its load realization model.

24             2. Bifurcated Load Model: Georgia Power should develop two distinct load forecast  
25             projections.

26      **Q:     CAN YOU EXPLAIN WHY YOU ARE RECOMMENDING THAT GEORGIA**  
27      **POWER SEPARATE ITS LOAD REALIZATION MODEL TO DEVELOP TWO**  
28      **LOAD FORECAST PROJECTIONS?**

1 A: Georgia Power should develop at least two load forecasts in IRPs in order to evaluate the  
2 different level of resource needs required depending on the forecast evaluated. I typically  
3 recommend that a Commission only plan new generation resources for large load  
4 customers that have a financial commitment to the utility. This ensures better certainty that  
5 the investments made will, in fact, be needed. In fact, this is the approach that Georgia  
6 Power uses when evaluating transmission projects. In response to a document response,  
7 Georgia Power explains that “[o]nce the Company received either an RFS or CES from the  
8 customer, the load along with associated projects are modeled in the official transmission  
9 planning base cases and included in the expansion planning processes. This process is also  
10 used for similar loads signed by other load serving entities in the Integrated Transmission  
11 System.”<sup>30</sup>

12 If Georgia Power is unable to reliably predict growth for customers who do not have a  
13 financial commitment to Georgia Power (technical review customers), the Commission  
14 should plan resources only for the projected growth from customers with a firm  
15 commitment to Georgia Power.

16 Put another way, while Georgia Power’s load realization model tries to capture some of  
17 the uncertain variables connected with trying to forecast new large load customer growth,  
18 it does not reflect the risk inherent with customers that have no commitment to Georgia  
19 Power, or those customers designated as technical review. Developing and evaluating a  
20 base forecast that only includes those customers that Georgia Power deems as committed  
21 and then developing additional forecasts for sensitivities with alternative assumptions, such  
22 as including prospective customers in the forecast, can be used to evaluate the level of  
23 resources needed across each forecast. This will also help clarify the level of load that  
24 drives resource decisions and the impact of overbuilding capacity if prospective customer  
25 load does not materialize.

26 3. Project Delay Risk: Georgia Power understates the length of delay that its prospective  
27 customers are likely to encounter.

---

<sup>30</sup> Georgia Power response to STF-DEA-3-6 subpart c.

1 **Q: CAN YOU EXPLAIN HOW YOU DEVELOPED AN UPDATED PROBABILITY**  
 2 **THAT REPRESENTS A PROJECT DELAY?**

3 A: To update the probability of a project delaying its projected start date, I evaluated the  
 4 customers with project delays spanning from the 2023 IRP load realization model to the  
 5 fourth quarterly report.<sup>31</sup>

6 I tracked reported delays by customer. For some customers, there were several  
 7 modifications made over the course of the four different quarterly reports. Since there were  
 8 a number of customers with more than one change, I took the aggregate change for those  
 9 customers.<sup>32</sup>

10 Delay probabilities are assigned in theory by Georgia Power based on a customer's industry  
 11 classification (i.e., data center, batteries, etc.). However, in reality, Georgia Power assigns  
 12 all customers the same likelihoods of delay.

13 For any customer segment with over three customers, I developed a minimum, median,  
 14 and maximum value to include in the load realization model. (I set a cutoff of having at  
 15 least three customers per customer segment in order to ensure that there would be enough  
 16 data to develop the minimum, most likely, and maximum values for the triangular  
 17 distribution. I capped the "minimum" delay at zero, or no delay.) So if a customer class  
 18 included a customer that sought to accelerate its initially requested service date, that  
 19 customer class's minimum delay would remain zero, because Georgia Power does not have  
 20 an obligation to accelerate the service date for a customer after a contract has been signed.

21 Georgia Power assumes a triangular distribution for the delay probability. This means that  
 22 the probability is represented by a minimum, most likely, and maximum value. **Table 9**  
 23 shows a comparison between the probabilities Georgia Power assumed and the changes I  
 24 made based on the data in the quarterly load reports. For the data center customer segments,  
 25 the divergence between the assumption I developed and what Georgia Power assumed is

---

<sup>31</sup> In the forecast developed for the IRP, Georgia Power only used data up through the second quarter report for purposes of developing a forecast for the IRP. 2025 IRP Main Document at 36, fn. 29. I used data that extended beyond what Georgia Power used to develop the load forecast for the 2025 IRP, but I used the data to evaluate the impact of updating the probabilities.

<sup>32</sup> For example, if Customer A announced a 6-month delay in the Q1 Report and then announced a second delay of 12 months in the Q4 report, I summed those together to be an 18-month delay for that customer.



for the maximum values. The battery manufacturing and other customer segments result in higher values for the most likely and maximum values used to develop the triangular distribution.

Customer Segment		Min <sup>33</sup>	Most Likely	Max
Data Centers – Big Tech	GPC IRP Assumptions	0	6	54
	GPC's 2023 IRP - Q4 Data	0	6	54
Data Centers - Developers	GPC IRP Assumptions	0	6	45
	GPC's 2023 IRP - Q4 Data	0	6	45
Battery Manufacturing	GPC IRP Assumptions	0	9	18
	GPC's 2023 IRP - Q4 Data	0	9	18
Other	GPC IRP Assumptions	3	15	21
	GPC's 2023 IRP - Q4 Data	3	15	21

**Table 9. Comparison of Modified Delay Probability**

4. New assumptions significantly impact load growth sensitivities.

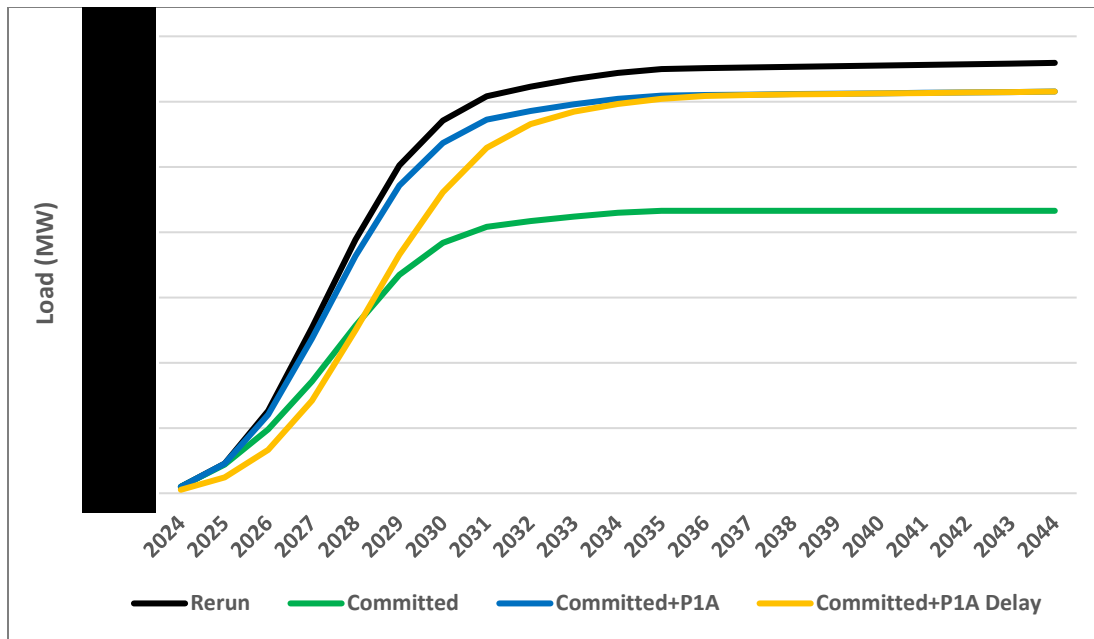
**Q: HOW DOES THE LEVEL OF PROJECTED LOAD FROM GEORGIA POWER'S LOAD REALIZATION MODEL CHANGE WHEN YOU INCLUDE YOUR ALTERNATE ASSUMPTIONS?**

**A: Figure 1** shows the results of the three different forecasts I evaluated with modified assumptions:

1. Only including committed customers ["Committed"]
2. Adding the P1A probability to technical review customers ["Committed + P1A"]
3. Adding the P1A probability to technical review customers and applying the project delay probability to all customers ["Committed + P1A Delay"]

All forecasts include the unexplained discount Georgia Power applied that I discussed earlier in my testimony.

<sup>33</sup> Any values with a negative minimum were set to be 0 months.



**Figure 1. Alternative Load Realization Model Runs (MW)**

**Q: ARE YOU RECOMMENDING THAT THE COMMISSION PLAN TO THESE CURVES?**

A: No. These curves are generated based on a limited set of adjustments for demonstrative purposes of the impact of these adjustments. These curves illustrate that updating the project delay probability and incorporating the risk of technical review customers leaving the queue results in significantly lower demand projections.

**Q: IS THERE ANYTHING ELSE TO NOTE ABOUT GEORGIA POWER'S LOAD REALIZATION MODEL?**

A: Yes, as I noted earlier in my testimony, there are additional indicators that the load model is overstating load, that are not captured in the above curves. These curves do not yet adjust for overstated ramp rates or the probability that Georgia Power's assumptions about the likelihood that a project's announced load will actually materialize on the system.

5. Additional concerns not captured in load growth sensitivities above: load ramp & materialization rates.

**Q: PLEASE EXPLAIN FURTHER YOUR CONCERNS ABOUT LOAD RAMP PROBABILITIES THAT ARE NOT CAPTURED IN THE ABOVE CURVES?**

A: The above curves do not correct the data to adjust for customers' demonstrated tendency to overstate how quickly they will need to ramp up their energy usage. While the project delay probability captures the uncertainty around delays to the project online date, there is another risk with the new large load customers and that is the projected load ramp rate provided by customers. **Table 10** shows a comparison of the load ramp changes that occurred between each of the quarterly load reports submitted by Georgia Power. The changes reflected represent an aggregate load ramp change across the customer projects.

Year	Q1 <sup>34</sup>	Q2	Q3	Q4
2024	-108	-111	-20	-37
2025	-449	-717	-57	-25
2026	-599	-1,390	-431	-547
2027	-692	-872	-835	-1,098
2028	-493	-800	-634	-1,179
2029	-405	-393	-378	-1,143
2030	-465	-411	-393	-1,413
2031	-559	-294	-311	-1,201
2032	-599	-290	-10	-1,158
2033	-515	-276	62	-1,069
2034	-458	-261	134	-957
2035	-425	-328	134	-957
2036	-425	-360	134	-957
2037	-204	-581	134	-957

**Table 10. Changes in Quarterly Load Reports: Ramp Rate**

For the majority of the years, each quarterly load report is projecting a downward adjustment to the customer's load ramp rate. Whatever the reason for the modification, the data from the quarterly load reports indicates a pattern of downward adjustment on projected load ramp rates.

**Q: PLEASE EXPLAIN YOUR CONCERNS ABOUT GEORGIA POWER'S ASSUMPTIONS ABOUT HOW CUSTOMERS' ANNOUNCED LOAD WILL MATERIALIZE ON THE SYSTEM.**

---

<sup>34</sup> Reflects difference between models prior to the Quarter One Report.

A: Georgia Power assigns values to a project’s likelihood of actually demanding the load it forecasts. The value used by Georgia Power is a probability for the difference between “announced” versus “materialized load”, incorporated in the model. The current probabilities are reflected in **Table 11**. Georgia Power is using the values below to reflect how accurate each customer segment is at projecting their eventual load needs.

Customer Segment	Minimum	Most Likely	Maximum
Cryptocurrency			
Data Centers - Big Tech			
Data Centers - Developers			
Industrial Segments			

**Table 11. Metered vs. Announced Load: Triangular Distribution Values**<sup>35</sup> These values are very high, and I recommend that Georgia Power reevaluate these thresholds—at least for data centers—using updated information about data center development from the market, until it has data from its own customers.

Furthermore, it is concerning that Georgia Power has assigned the same value to data centers run by “developers” as data centers run by “big tech.” In practice, this means that Georgia Power is assuming that data center developers are as likely to accurately predict their load as data centers run by big tech. This is not a reasonable assumption: Developers may sign a request for service with Georgia Power before even identifying an off-taker for its site.

Counsel for GIPL and Southface asked Georgia Power about this assumption at the direct hearings, and Georgia Power responded that “at the time of developing the forecast [in 2023], [it] didn’t have all the information available” and that there were not as many data center developers in the pipeline at that time.<sup>36</sup> When developing this assumption for the 2023 IRP, Georgia Power had to rely on “informed judgment” alone, because there was “no historical data that can serve as a guide for the forecast.”<sup>37</sup>

<sup>35</sup> Georgia Power workpaper named “Budget 2025 Load Realization Model TRADE SECRET”.

<sup>36</sup> 2025 Direct Hr’g Tr. 522:23-523:10.

<sup>37</sup> Georgia Power response to STF-DEA-1-8 (Docket 55378), *attached as* Exhibit CH-4.

1 Both assertions by Georgia Power are true: It has more data now, and it also has a far higher  
2 percentage of developers in its pipeline now. However, the impact of these assumptions on  
3 the load forecast is highly significant. I recommend Georgia Power update these  
4 assumptions.

5 **Q: YOU UTILIZED DATA FROM THE QUARTERLY REPORTS TO MODIFY THE**  
6 **PROJECT DELAY PROBABILITY. WHY DID YOU NOT USE THE SAME**  
7 **APPROACH TO MODIFY THE ANNOUNCED VERSUS METERED LOAD**  
8 **PROBABILITY?**

9 A: I chose not to modify the announced versus metered probability because my review focused  
10 on the large load materialization data, and there are not yet enough data points from the  
11 announced load and customers that have broken ground, constructed their facilities, and  
12 are online to test Georgia Power's assumptions. However, I do not agree that the  
13 assumptions made in the load realization model are an accurate reflection of what the ratio  
14 of load will be. For instance, the data from the quarterly load reports does indicate that  
15 customers have announced changes to their announced load levels. And as shown in **Table**  
16 **11**, data center customers are assigned higher announced versus metered values than the  
17 other customer segments in the load realization model.

18 It will be imperative for Georgia Power to update these assumptions, especially as it relates  
19 to data centers, since they are a substantial portion of the load queue.

20 Similar to Georgia Power, ERCOT is forecasting significant growth from data center  
21 customers. For ERCOT's 2025 long-term demand energy forecast, adjustment factors were  
22 applied based on actual observations of large load projects. ERCOT reviewed the requested  
23 MWs compared to the peak consumption for each Data Center site that had in-service dates  
24 in 2022 through 2024 and found that the average peak consumption per site was 49.8% of  
25 the requested MW.<sup>38</sup> This data from ERCOT supports the conclusions that the values

---

<sup>38</sup> 2025 ERCOT System Planning Long-Term Hourly Peak Demand and Energy Forecast at 9 (Apr. 8, 2025).  
Retrieved from <https://www.ercot.com/files/docs/2025/04/08/ERCOT-2025-Long-Term-Load-Forecast-Report.pdf>

Georgia Power assumes for the announced versus metered load are considerably overstated for data center customers.

**Q: YOU HAVE NOT DISCUSSED THE ADDITIONS TO GEORGIA POWER'S LOAD QUEUE BETWEEN THE SECOND QUARTERLY REPORT AND THE FOURTH QUARTERLY REPORT. IS THERE ANYTHING TO NOTE ABOUT THE ADDITIONAL LOAD REFLECTED IN THOSE REPORTS?**

**A:** One thing to note about the new prospective customers added to Georgia Power's load queue between the second quarterly report and the fourth quarterly report is the timing of when these prospective customers are requesting service. When looking at a total projected MW load number from the reports, it is hard to understand the disaggregated project-specific data. **Table 12** shows a comparison of the number of new customers requesting to start service between the years 2023 – 2030. Each column to the right of "Q1" reflects the new requests added to the queue and reported for that quarter.

Year	Q1	New Q2	New Q3	New Q4
2023	1	2	2	0
2024	12	2	7	1
2025	25	9	14	7
2026	15	4	7	7
2027	6	0	1	3
2028	2	0	0	0
2029	2	0	0	0
2030	1	0	0	0

**Table 12. Quarterly Load Report Comparison**

The data reported by Georgia Power indicates that all of Georgia Power's new prospective customers between Q2 and Q4 requested in-service dates between 2024 – 2027. Furthermore, the average load request from a new customer has been rising:

- The average in Q2 for new requests is 393 MW.
- The average in Q3 for new requests is 487 MW.
- The average in Q4 for new requests is 678 MW.

These trends raise questions about the realistic nature of the timing and size of the load needs of customers. These trends also raise many questions about how to manage requests

1 compared to the level of load that can be served under timelines needed to add new  
2 generation and maintain reliability for Georgia Power's existing customers. For example,  
3 for new prospective customers entering the load queue and requesting an in-service date  
4 between 2025-2027, will these customers remain in the queue and ask for a later in-service  
5 date? Will these prospective customers modify their announced load level? Will these  
6 prospective customers modify their announced load level and ramp rate? All of these  
7 questions heighten the risk related to prospective customers that have not made a  
8 commitment to Georgia Power.

9 **D. Recommendations**

10 **Q: WHAT RECOMMENDATIONS DO YOU HAVE FOR THE LOAD**  
11 **REALIZATION MODEL?**

12 A: I appreciate that Georgia Power updated its approach and is incorporating the P50, or 50<sup>th</sup>  
13 percentile, from the results of the load realization model, and that Georgia Power is  
14 monitoring some data relevant to the assumptions in the model. This is a significant  
15 improvement from the 2023 IRP. Despite this improvement, there are other areas in the  
16 model that need to be updated in order for Georgia Power to continue to use this model to  
17 develop a forecast of new large load customers. I offer the following three  
18 recommendations:

- 19 1. Georgia Power should utilize the data from the Quarterly Load Reports to  
20 update the inputs and probabilities in the load realization model.
- 21 2. Georgia Power should reflect the additional risk from technical review  
22 customers by incorporating a probability to reflect the dropout rate for these  
23 prospective customers.
- 24 3. Georgia Power should develop two load forecasts for planning purposes. The  
25 first forecast should only include the committed customers, or those customers  
26 with signed contracts or Requests for Service. The second forecast should build  
27 upon the first and layer in the projected load from the customers considered to  
28 be under the technical review status. Performing modeling with both forecasts

1 will provide a range of resources needed to meet Georgia Power's winter  
2 reserve margin.

3 **Q: WHAT RECOMMENDATIONS DO YOU HAVE FOR THE COMMISSION AT**  
4 **THIS TIME CONCERNING THE LOAD REALIZATION MODEL?**

5 A: I recommend that the Commission not approve Georgia Power's projected growth as part  
6 of its integrated resource plan at this time. Instead, I recommend the Commission order  
7 Georgia Power to update its load projections using available load growth data to modify  
8 assumptions to reflect more rigorous analysis of available information. I further  
9 recommend this update differentiate between customers committed to Georgia Power and  
10 prospective customers. In my opinion, the large load model data provided by Georgia  
11 Power to support this IRP is not reliable enough to plan substantial resource investments.

12 **IV. RESERVE MARGIN STUDY**

13 **Q: HAS GEORGIA POWER UPDATED ITS WINTER RESERVE MARGIN BASED**  
14 **ON THE RESERVE MARGIN STUDY PERFORMED FOR THE 2025 IRP?**

15 A: Yes. Southern Company performed an updated reserve margin study, which Georgia Power  
16 relies on for this IRP.

17 **Q: DO YOU HAVE ANY CONCERNS WITH HOW SOUTHERN COMPANY**  
18 **CONDUCTED ITS RESERVE MARGIN STUDY.**

19 A: Yes. I am concerned about the modeling approach used for large loads in the reserve margin  
20 study. The approach used by Georgia Power may overstate the necessary reserve margin.  
21 Large loads do not respond to extreme weather in the same way that typical loads respond,  
22 so unless large loads are treated differently in the model, there is a significant likelihood  
23 that the model will overstate the reserve margin required for extreme weather events. In  
24 addition, load forecast error could be double counted by using a load realization model in  
25 the load forecast, which accounts for load forecast error, and by scaling up the reserve  
26 margin for additional load forecast error. I explain both of these concerns further in my  
27 testimony.



To identify the precise impact of this modeling choice would require modeling alternative scenarios in SERVVM, which I have not done as part of this analysis. However, Southern Company's choice to model large loads like other loads in its system could substantially overstate the required reserve margin because a large percentage of the entire Southern Company projected load is classified as large load customers (■%). In addition, a large portion of the reserve margin—nearly half of it—is directly attributable to the model's predictions about weather response and load forecast error.

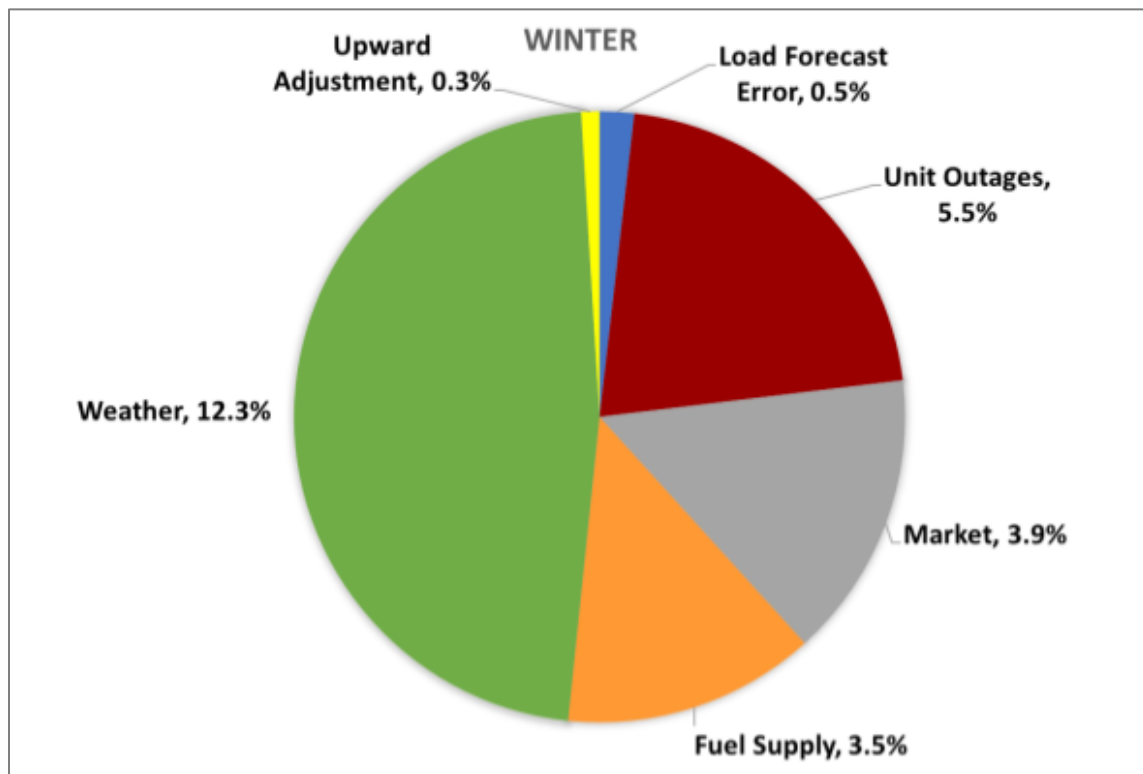


Figure 2. Components of Winter TRM<sup>39</sup>

**Q: DO YOU HAVE ANY RECOMMENDATIONS RELATED TO HOW GEORGIA POWER MODELED THE NEW LARGE LOAD CUSTOMERS IN THE TARGET RESERVE MARGIN STUDY?**

**A:** Yes. I recommend that Southern Company modify its approach for how new large load customers are modeled in its reserve margin study, to more accurately reflect large load's

<sup>39</sup> 2025 Tech. Appx. 1, PD-An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System at 60, Fig. III.13.

1 response to extreme weather. Specifically, I recommend that Southern Company model  
 2 large load customers like a negative generator in the modeling process, so that the model  
 3 does not inappropriately scale up large load demand in response to extreme weather events.

4 **Q: PLEASE EXPLAIN YOUR MODELING RECOMMENDATION.**

5 A: Southern Company uses the Strategic Energy and Risk Valuation Model (“SERVM”)  
 6 model to perform its Reserve Margin Study. One of the risks the SERVM model captures  
 7 is uncertainty from weather. In the model, a multitude of weather years, or 1973-2022 in  
 8 Georgia Power’s modeling,<sup>40</sup> are included to reflect different weather across these years.  
 9 The way SERVM works is that a future study year is selected, (Georgia Power selected  
 10 2028<sup>41</sup>), and one of the inputs into the model is the projected load forecast for that future  
 11 study year. In SERVM, there will be an 8,760 hourly shape for each weather year between  
 12 1973 and 2022. The SERVM model uses historical weather patterns to develop load  
 13 profiles for each weather year in the study to predict how loads would respond if the  
 14 weather experienced in that particular year were to repeat. Put another way, the hourly load  
 15 for 1973 represents how load will respond if the 1973 weather conditions occur in the study  
 16 year.

17 SERVM sees this projected load forecast and scales the historical loads so that the average  
 18 or median<sup>42</sup> peak demand from those historical weather years matches the projected energy  
 19 and peak demand for the study period. It is my understanding that Georgia Power included  
 20 the new large load customers as part of those projected peak values.<sup>43</sup> As Georgia Power  
 21 said:

---

<sup>40</sup> 2025 Tech. Appx. 1, TS-An Economic and Reliability Study of the Target Reserve Margin for the Southern Company System (“Reserve Margin Study”) at 1.

<sup>41</sup> *Id.*

<sup>42</sup> Either the average or median can be specified by the user.

<sup>43</sup> Georgia Power response to STF-PIA-5-12 subpart a (the Company confirmed that forecasted economic development projects are included in the System Peak Load values).

1 The 2024 Reserve Margin Study was performed with seasonal  
 2 peak load defined, and the model adjusted weather year load  
 3 shapes based on those seasonal peak load values. The following  
 4 2028 System Peak Load values were used for all primary and  
 5 sensitivity studies: 32,986 MW (Spring), 39,138 MW  
 6 (Summer), 38,309 MW (Winter), and 30,286 MW (Autumn).  
 7 Utilizing these peak loads and related energy forecasts, the  
 8 model applied a scaling algorithm to adjust the individual  
 9 weather year load shapes.<sup>44</sup>

10 Modeling large load customers in this manner means that they will be impacted by the  
 11 different weather patterns inherent in the weather years evaluated in SERVVM. For large  
 12 load customers that are not sensitive to weather, this is not the approach that should be  
 13 used.<sup>45</sup> Instead of the approach used by Georgia Power, new large loads should be modeled  
 14 like a negative generator in SERVVM.<sup>46</sup> Under this approach, the new large loads could  
 15 have a specific 8,760 shape assigned that reflects the seasonal changes in the load shape.  
 16 The difference between these seasonal impacts is that they are expected based on the  
 17 cooling needs of a data center. Modeling new large loads in this manner will better reflect  
 18 the expected operations of these customers and will prevent them from being included in  
 19 the load forecast that is scaled in SERVVM for the weather years included in the study.

20 **Q: WHY ARE YOU MAKING THIS RECOMMENDATION FOR GEORGIA POWER**  
 21 **TO MODIFY ITS APPROACH TO MODELING NEW LARGE LOAD**  
 22 **CUSTOMERS IN SERVVM?**

23 **A:** If new large load customers are included in the projected peak load forecast input into  
 24 SERVVM, this means they will be subject to the scaling algorithm within SERVVM. The  
 25 result is that the scaling could overestimate the load related to new large load customers.  
 26 Georgia Power's forecast for new large load customers in the 2028 study year is [REDACTED]  
 27 MW,<sup>47</sup> or approximately [REDACTED] % of the Southern Company system summer peak modeled in  
 28 the 2028 study year in SERVVM. With the projected load growth from Georgia Power's

<sup>44</sup> 2025 Tech. Appx. 1, TS-Reserve Margin Study at 12.

<sup>45</sup> Georgia Power testified that the SERVVM model was "trained" on customer behavior using "training data from 2018 through 2022," but the data center loads accounted for in that sample are small. 2025 Direct Hr'g Tr. 407:10-24.

<sup>46</sup> Depending on the version of SERVVM used, this can be modeled as a Load Modifier.

<sup>47</sup> Derived from 2025 Tech. Appx. 1, TS-Load and Energy Forecast, Table 7.2.1 at 108.

1 model, future study years will have an even larger share of new large load growth as a  
 2 percentage of the total Southern Company system peak. It is important for Georgia Power  
 3 to ensure that the modeling approach for including new large load customers in SERVUM  
 4 does not misrepresent the load response from these customers during weather events, which  
 5 could overestimate periods of risk in the model. When asked about the drivers of the  
 6 increase in reserve margin between the 2022 IRP and the 2025 IRP, Georgia Power said:

7 As described on page 52 of the 2024 Reserve Margin Study in  
 8 Technical Appendix Volume 1, Section 2, the winter loss of load  
 9 expectation (“LOLE”) at a 26% target reserve margin (“TRM”)   
 10 increased relative to the same winter TRM in the 2021 Reserve  
 11 Margin Study. This is due to increased peak load volatility and  
 12 sustained loads during overnight hours associated with customer  
 13 response to cold weather events. This impact is not associated  
 14 with high load factor loads under normal weather conditions.<sup>48</sup>

15 Georgia Power identifies response to cold weather events as a main driver in the LOLE  
 16 difference in the 2021 and 2024 reserve margin study. This underscores the importance for  
 17 Georgia Power to modify how it incorporates new large load customers into SERVUM to  
 18 ensure that these customer loads do not face the same scaling within SERVUM to respond  
 19 to weather events since they are not a weather responsive load. **Figure 3** shows the  
 20 historical low winter temperatures for the weather years modeled in SERVUM. The years  
 21 with the lowest temperatures are 1982, 1983, and 1985.

22 Notably, when I reviewed the SERVUM output files included in Georgia Power’s  
 23 workpapers for the reserve margin study, the weather years 1982, 1983, and 1985 account  
 24 for approximately █% of the expected unserved energy (“EUE”) out of the total EUE  
 25 across all of the weather years modeled.<sup>49</sup>

---

<sup>48</sup> Georgia Power response to STF-JKA-3-6 subpart a.

<sup>49</sup> Georgia Power workpaper named “B24 Winter RMS\_Final\_Monthly Average\_SystemMetrics (TS)”. I filtered for study results for the Unit Modifier named “Base;B24 Tier Cal;RM26-Winter”.

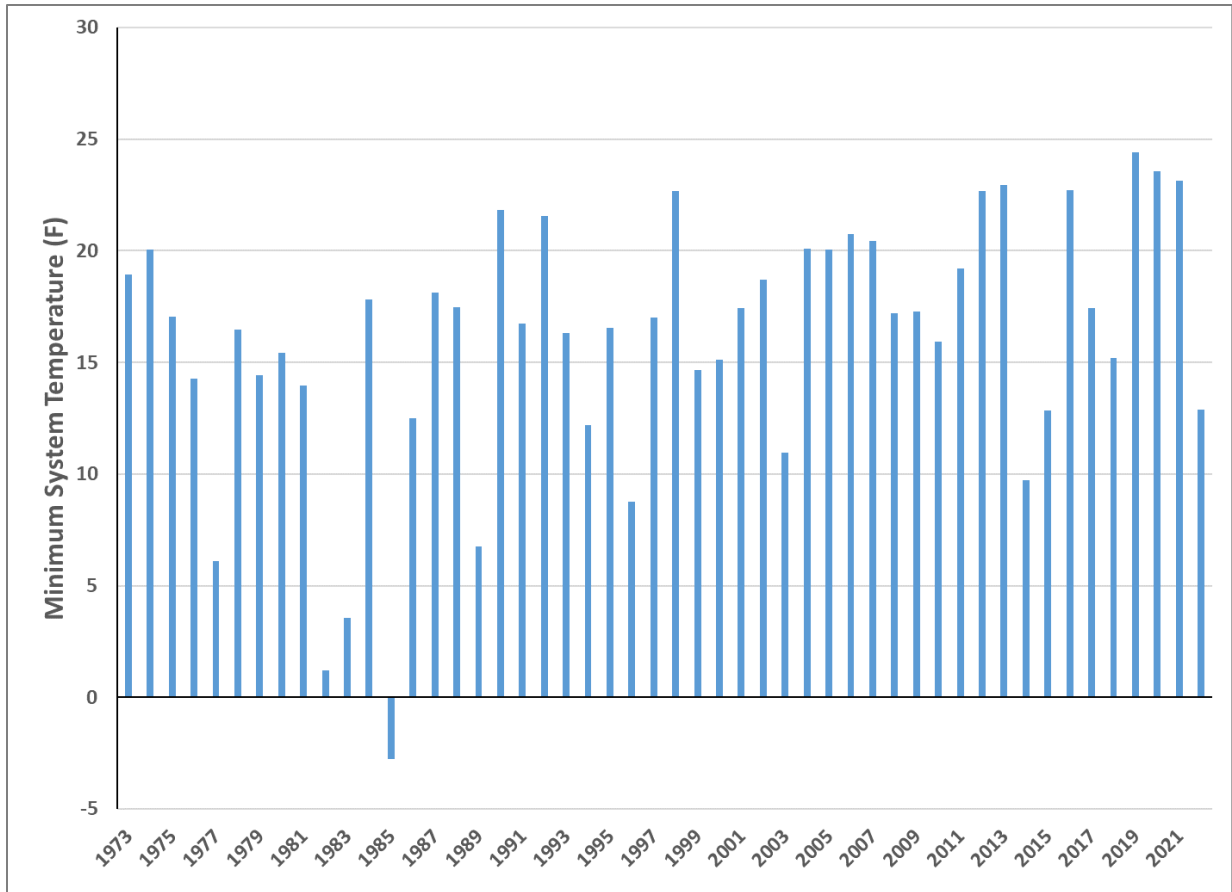


Figure 3. Historical Low Winter Temperatures<sup>50</sup>

**Q: IS THERE ANOTHER REASON WHY YOU RECOMMEND THAT GEORGIA POWER MODIFY ITS APPROACH TO MODELING NEW LARGE LOAD CUSTOMERS IN SERV?**

**A:** Yes. Modeling the large load customers like a negative generator instead of including their load in the projected peak forecast means their load will not be impacted by any load forecast errors (“LFE”) specified in SERV. If load forecast errors are specified, this means that cases will be run in SERV that apply those errors to the load forecast. For instance, if you have a load forecast error of +2%, this means the load will be adjusted upward by 2%, and if there is a load forecast error of -2%, then the load will be adjusted downward by 2%. Each load forecast error is assigned a probability, which weights the load forecast errors.

<sup>50</sup> 2025 Tech. Appx., TS-Reserve Margin Study, Figure I.1 at 3.

1 For the load forecast errors Georgia Power includes in its SERVVM modeling, there are two  
2 components of the error. One component represents economic error and the other  
3 represents load forecast model error. Georgia Power developed the economic error based  
4 on differences in the high and low economic scenarios from the U.S. Energy Information  
5 Administration (“EIA”) 2023 Annual Energy Outlook and then weighted by the system  
6 class weights for residential, commercial, and industrial customers.<sup>51</sup> Georgia Power  
7 developed the model error based on variances between actual historic load to model-fitted  
8 load.<sup>52</sup> The result of Georgia Power’s process for calculating load forecast errors is a range  
9 between -6.12% to 5.16%.

10 Staff asked Georgia Power about the potential of double counting the application of these  
11 load forecast errors to new large load customers. Georgia Power’s response to that question  
12 was that the economic error was based on the EIA 2023 Annual Energy Outlook and  
13 “represents a more traditional view of economic uncertainty. It is, therefore, not duplicative  
14 of the risk adjustments applied to the Georgia Power load forecast for large load  
15 customers.”<sup>53</sup> I disagree with Georgia Power on the concern of double counting. The load  
16 realization model used to develop the projection of new large load customers that are  
17 included in the peak forecast reflects some risks around those customers through the  
18 probabilities that are included in the model. Georgia Power developed the load realization  
19 model because the economics of the large load customers could not be captured through  
20 traditional regression models, like those used to develop forecasts for the other customer  
21 classes. It is not accurate to develop a model that reflects risks around these customers and  
22 then apply a second adjustment through the load forecast error in SERVVM. Utilizing the  
23 alternative approach I have suggested for modeling new large loads will help prevent an  
24 overestimation of risk during cold weather responses and prevent any double adjustment  
25 of load forecast error.

---

<sup>51</sup> 2025 Tech. Appx., TS-Reserve Margin Study at 13-14.

<sup>52</sup> 2025 Tech. Appx., TS-Reserve Margin Study at 13-14.

<sup>53</sup> Georgia Power response to STF-JKA-3-3.

1 **Q: ARE OTHER UTILITIES MODIFYING THE APPROACH TO MODELING NEW**  
 2 **LARGE LOAD CUSTOMERS IN SERVVM?**

3 A: In my role at EFG, I participate in the Duke Energy Indiana and Santee Cooper IRP  
 4 stakeholder meetings. For Duke Energy Indiana's 2024 IRP, EFG provided the  
 5 recommendation to model large load customers and electric vehicle load as a negative  
 6 generator instead of including those loads in the projected peak forecast. With regard to  
 7 future enhancements related to SERVVM modeling, Duke said in its IRP:

8 To that end, stakeholders have identified assumptions, which  
 9 bear further investigation in future modeling activities,  
 10 particularly around the load simulations used in the SERVVM  
 11 analysis. These include: (1) the shape and weather- response of  
 12 potential future high-load factor large customers such as data  
 13 centers, and (2) the treatment of electric vehicle loads and  
 14 charging strategies. These and other potential determinants of  
 15 modeled reliability will continue to be evaluated in future efforts  
 16 to more accurately characterize potential risks to Duke Energy  
 17 Indiana customers.<sup>54</sup>

18 As a stakeholder participant in the Santee Cooper IRP meetings, Santee Cooper brought its  
 19 consultant and vendor for the SERVVM model, Astrapè, to discuss the changes that would  
 20 be implemented for the planning reserve margin ("PRM") and effective load carrying  
 21 capability ("ELCC") studies for the 2026 IRP. One of the items noted by Astrapè during  
 22 that meeting was disaggregating load components into separate load shapes and the  
 23 categories referenced in the presentation included energy efficiency, electric vehicles, and  
 24 datacenters.<sup>55</sup>

---

<sup>54</sup> 2024 Duke Energy Indiana IRP, Appendix E at 408-09 (Nov. 1, 2024). Retrieved from <https://www.duke-energy.com/-/media/pdfs/for-your-home/dei-irp/2024-plan-and-attachments/vol-i-complete-2024-dei-irp-plan.pdf?rev=93f4e009ddfc44b0baa3f94f3e195b4a>

<sup>55</sup> Santee Cooper Stakeholder Working Group Meeting #4 at 33 (Nov. 13, 2024). Retrieved from [https://www.santeecooper.com/About/Integrated-Resource-Plan/2026-IRP-Stakeholder-Process/\\_pdfs/Santee-Cooper-IRP-Working-Group-Meeting-4-FINAL.pdf](https://www.santeecooper.com/About/Integrated-Resource-Plan/2026-IRP-Stakeholder-Process/_pdfs/Santee-Cooper-IRP-Working-Group-Meeting-4-FINAL.pdf)

**Q: DURING YOUR REVIEW OF THE RESERVE MARGIN STUDY, WERE THERE ANY OTHER NOTABLE FINDINGS THAT YOU WISH TO HIGHLIGHT?**

**A:** Yes. One of the findings from the reserve margin study is that the 1:10 Loss of Load Expectation (“1:10 LOLE”), or industry standard of .1 day/year, is higher than the economic optimum reserve margin (“EORM”). This is a change from previous studies. As Georgia Power said:

Except for the 2018 Reserve Margin Study, the annual 1:10 LOLE threshold within the Southern Company System has historically occurred at reserve margins at or below the EORM. Thus, EORM and the risk-adjusted EORM have historically been the primary focus when determining the TRM. However, as the Company continues to update reliability risks in its modeling, the 2024 analysis has indicated that the LOLE for the System, particularly in the Winter season, is higher than in years past. Thus, the reserve margin necessary to maintain the 1:10 LOLE threshold is also higher. Similar to the 2018 Reserve Margin Study, the 1:10 LOLE threshold in the 2024 Reserve Margin Study also exceeds the EORM.<sup>56</sup>

To develop Georgia Power’s target reserve margin (“TRM”), Georgia Power takes an additional step to evaluate the expected costs of maintaining reserve capacity, production costs, and reliability costs to determine the economic optimum reserve margin (“EORM”). This evaluation considers the tradeoff between the costs of additional generating capacity on the system versus the improvement in resource adequacy from having those additional generating resources. Georgia Power evaluated the EORM by comparing the production<sup>57</sup> and reliability<sup>58</sup> costs, as determined by the SERVVM model, to the incremental capacity cost of new generation over several different winter planning reserve margin levels (ranging from 20% to 30%) to find the point where the sum of the production costs, reliability costs, and incremental capacity costs is minimized. Georgia Power then takes an additional step to calculate the potential to mitigate high-cost outcomes using the Value at

<sup>56</sup> 2025 Tech. Appx., TS-Reserve Margin Study at 52.

<sup>57</sup> Production costs include the cost of generation (such as fuel and variable O&M) and costs of market purchases.

<sup>58</sup> Reliability costs include the cost of expected unserved energy, emergency market purchases, and the cost to call demand response resources.



Risk (“VaR”) metric. The VaR evaluates the difference in cost at the expected value and the cost at a specified confidence interval. Georgia Power looks at the cost to move from one reserve margin to the next and compares the incremental increase in reserve margin to the incremental decrease in VaR.

**Table 13** shows a comparison of the recommended winter TRM, the 1:10 LOLE TRM, and the EORM for the 2022 and 2025 IRP reserve margin studies. In the 2022 IRP, Georgia Power recommended a 26% winter TRM since it fell within confidence intervals (80<sup>th</sup> percentile) considered for the VaR.<sup>59</sup> For this IRP, Georgia Power is recommending a 26% winter TRM since the 1:10 LOLE is 25.75%, and 26% falls within the confidence intervals considered for the VaR.<sup>60</sup>

Study	Recommended	1:10 LOLE	EORM
2022 IRP	26%	20.00% <sup>61</sup>	24.25% <sup>62</sup>
2025 IRP	26%	25.75% <sup>63</sup>	22.75% <sup>64</sup>

**Table 13. Comparison of Winter Reserve Margins**

## V. THE RESOURCE MIX STUDY

**Q: DID YOU HAVE ACCESS TO THE MODEL THAT GEORGIA POWER USES TO PERFORM CAPACITY EXPANSION MODELING FOR THE RESOURCE MIX STUDY?**

**A:** Yes, I did have access to the AURORA model. I appreciate that Georgia Power facilitated conversations with Energy Exemplar to allow intervenors to receive access to an intervenor project license. Without the assistance of Georgia Power, it would be unlikely that we could have secured an intervenor license through Energy Exemplar.

<sup>59</sup> 2022 Tech. Appx., Public-Reserve Margin Study at x.

<sup>60</sup> 2025 Tech. Appx., TS- Reserve Margin Study at 70.

<sup>61</sup> 2022 Tech. Appx., Public-Reserve Margin Study at 49.

<sup>62</sup> 2022 Tech. Appx., Public-Reserve Margin Study at 38.

<sup>63</sup> 2025 Tech. Appx., TS-Reserve Margin Study at xi.

<sup>64</sup> 2025 Tech. Appx., TS-Reserve Margin Study at 43.

1 **Q: BEFORE YOU DISCUSS THE ALTERNATIVE MODELING RUNS YOU**  
 2 **PERFORMED IN AURORA, ARE THERE ANY LIMITATIONS THAT YOU**  
 3 **WANT TO NOTE?**

4 A: Yes, I do want to mention a few limitations. First, with docketed proceedings, there is a  
 5 tight timeframe for which intervenors can perform alternative modeling. Performing  
 6 alternative modeling involves reviewing the model developed by the utility, evaluating  
 7 modeling input assumptions, determining which input assumptions to modify, setting up  
 8 those modified inputs, running the model, and reviewing model output. Due to time  
 9 constraints, I had to narrow my focus to evaluate a limited set of issues.<sup>65</sup> If I had more  
 10 time, I would have explored additional modeling runs, such as looking at the different  
 11 pathways for Plant Bowen and Plant Scherer. In addition, assumptions had to be made  
 12 given the lack of intervenor ability to ask discovery questions. It is challenging to not be  
 13 able to ask discovery questions to follow up on Georgia Power's modeling inputs and  
 14 assumptions or to request additional information if it is needed. As it pertains to the  
 15 alternative modeling I performed, I encountered some challenges with assumptions for the  
 16 new large load customers and energy efficiency. I will highlight these particular inputs in  
 17 more detail later below as I explain the alternative modeling runs presented in my  
 18 testimony.

19 **A. Alternative Modeling Runs: I tested the impact of 5 sensitivities on the economically**  
 20 **optimal resource mix recommended by Aurora.**

21 **Q: CAN YOU EXPLAIN THE PROCESS YOU USED TO DEVELOP ALTERNATIVE**  
 22 **MODELING RUNS IN AURORA?**

23 A: I performed capacity expansion and production cost modeling using the AURORA  
 24 software to develop alternative portfolios using different input assumptions from what  
 25 Georgia Power modeled for this IRP. The modeling I performed in AURORA<sup>66</sup> utilized

---

<sup>65</sup> Through counsel for GIPL and Southface, I began to work on accessing Georgia Power's software systems (Aurora) in October 2024, but I was not granted access until March 2025. The compressed timeline to access these files limited my potential analysis.

<sup>66</sup> I used AURORA Version 14.2.1104 to perform the modeling presented in my testimony.

Georgia Power's "base case" (111 MG0) database that Georgia Power provided with its workpapers.<sup>67</sup>

I then made one input change to Georgia Power's "base case." I brought over information related to the existing unit uprates from the AURORA database used to develop the Unit Uprate analysis. These assumptions include Georgia Power's request to pursue investments that would add capacity to some of its existing thermal and nuclear resources. I included this assumption for all modeling runs presented in my testimony.

**Table 14** provides a list of the alternative modeling runs I have done using AURORA. I will discuss each modeling run in more detail below.

<b>Plan</b>	<b>Description</b>
GPC 111 + Uprates	GPC's base case, as modified to assume that Georgia Power performs upgrades to existing units (as it requests in 2025 IRP).
Alt DSM <sup>68</sup>	Adds new DSM assumptions.
Alt No P50	Plans for no new large load customers.
Alt Committed	Plans only for large load customers who have signed a RFS or ESA.
Alt Committed + P1A	Plans for all large load customers, adding in a new sensitivity using dropout rates for technical review customers.
Alt Committed + P1A and Delay	Plans for all large load customers, adding in two new sensitivities: One for technical review dropout rates and one for delayed start dates.

**Table 14. Alternative Modeling Runs**

**Q: WHAT DOES THE GPC 111 UPRATES MODELING RUN REPRESENT?**

A: The modeling run named "GPC 111 + Uprates" reflects Georgia Power's modeling assumptions with the inclusion of the assumed existing unit uprates that Georgia Power has requested as part of this IRP. Since I have included the existing unit uprates for all alternative modeling I performed, I needed to develop a new case for the representation of Georgia Power's 111 MG0 plan to include these existing unit uprates.

<sup>67</sup> 2025 Direct Hr'g Tr. 490:4.

<sup>68</sup> Demand Side Management.

**Q: WHAT DOES THE ALTERNATIVE PLAN WITH DSM REFLECT?**

A: The “Alt DSM” plan takes the GPC 111 + Uprates modeling run and incorporates energy efficiency estimates for the proposed case and demand response assumptions developed by Witness Sherwood. Please see Ms. Sherwood’s testimony for more detail on how those assumptions were developed. Based on the information Georgia Power provided on how energy efficiency was included in the load forecast modeled in AURORA,<sup>69</sup> it appeared there was a gap in the savings between Georgia Power’s DSM Plan and what was included in the IRP load forecast. In order to adjust for that difference, I incorporated the energy efficiency savings as an incremental reduction to the load forecast Georgia Power input into AURORA. The additional demand response developed by Witness Sherwood was modeled in AURORA as an increase to the winter and summer capacity for the existing demand response resource in the database. **Table 15** shows the incremental energy efficiency savings that were included in the model.

Year	Residential	Commercial
2025	165,549	124,848
2026	298,177	241,699
2027	431,957	358,693
2028	566,615	483,312
2029	701,771	611,328
2030	844,072	743,100
2031	985,727	878,140
2032	1,127,284	1,013,224
2033	1,268,953	1,148,308
2034	1,422,783	1,294,856
2035	1,597,854	1,451,120

**Table 15. Energy Efficiency Savings (MWh)<sup>70</sup>**

**Table 16** shows the incremental demand response savings that were modeled. A ramp period was modeled leading up to the full summer capacity of 125 MW in 2027.

<sup>69</sup> Georgia Power response to STF-JKA-1-1 Attachment C.

<sup>70</sup> Savings through 2059 were reflected in the load forecast modeled in AURORA.

Year	Summer (MW)	Winter (MW)
2025	42	14
2026	83	28
2027	125	42

**Table 16. Demand Response Savings (MW).**

**Q: HOW DID YOU MODEL MS. SHERWOOD'S ENERGY EFFICIENCY SAVINGS IN AURORA?**

A: In the resource mix study, Georgia Power modeled energy efficiency as a reduction to the hourly load forecast input into AURORA. In order to develop an hourly (8,760) shape to translate the annual energy efficiency savings, I developed a profile based on the 2024 hourly load profile from Georgia Power's hourly load forecast input into AURORA. Typically, I would rely on a utility's workpapers reflecting hourly values. But in this case, Georgia Power did not provide sufficient information to use this approach.

Staff requested the supporting workpapers Georgia Power used to develop the load forecasts presented in the IRP and incorporated into the AURORA modeling.<sup>71</sup> The provided workpapers only showed the translation of annual savings into monthly savings. Since I needed to be able to translate the annual savings developed by Witness Sherwood into hourly values to model as a reduction to the hourly load forecast, I had to make an alternative assumption.

**Q: CAN YOU EXPLAIN THE TECHNICAL PROCESS YOU USED TO APPLY THE DIFFERENT LOAD FORECASTS DEVELOPED IN THE ALTERNATIVE MODELING?**

A: In addition to running Georgia Power's modified base case and alternative DSM assumptions, I evaluated four different load forecasts in AURORA. Similar to the energy efficiency savings, the new large load customer forecast needed to be translated into an hourly forecast to be able to model within AURORA. Staff asked Georgia Power about the hourly shape used for new large load customers and Georgia Power did not provide any data with the response to Staff's question.<sup>72</sup> In order to have hourly values to reflect in

<sup>71</sup> Georgia Power response to STF-JKA-1-1.

<sup>72</sup> Georgia Power response to STF-PIA-5-7.

AURORA, I had to make assumptions around the shape of the new large load customers. In order to develop a shape, I took the quarterly peak values reported in the output from the load realization model and then made two adjustments. The first assumption was to adjust the values from the load realization model by a seasonal factor. I developed this by looking at the data provided in one of the data center customer's contract with Georgia Power for the projected monthly peak values. Under this approach, I have reflected seasonal adjustments expected for new large loads, especially as it relates to cooling in the summer, but it does not reflect any hourly variability. Given the large proportion of data center customers in the load realization model, I would not expect significant variation from hour to hour for these customers. I averaged the monthly adjustment factors by quarter so that they could be applied to the quarterly peak values from the load realization model.

The second assumption was to apply a quarterly loss expansion factor to the new customer load. Since Georgia Power develops a different expansion factor by customer class, I took the ratio of commercial and industrial commercials in the load realization model to develop a weight to apply to the expansion factors. I averaged the monthly expansion factors reported by Georgia Power to develop a quarter average that could be applied to the quarterly peak values from the load realization model. **Table 17** shows the result of the two adjustments that were applied to each alternative load forecast.

	Monthly Adjustment <sup>73</sup>	Expansion Factor <sup>74</sup>
Quarter One		
Quarter Two		
Quarter Three		
Quarter Four		

**Table 17. Quarterly Adjustment and Expansion Factors**

The process I used represents my best approximation of developing hourly forecasts to model in AURORA for the new large load customers. Since I was not able to replicate Georgia Power's exact process, there will be some differences because of this.

<sup>73</sup> Georgia Power Response to STF-PIA-1-10, Attachment R.

<sup>74</sup> 2025 Tech. Appx. 1, TS-B2025 Load and Energy Forecast, Attachment 6.07-7 at 96.

1 All of the forecasts also included the same discount discussed earlier in my testimony. I  
2 maintained this approach to be consistent with Georgia Power.

3 **Q: WHAT ARE THE DIFFERENCES IN THE ALTERNATIVE LOAD FORECASTS**  
4 **YOU DEVELOPED?**

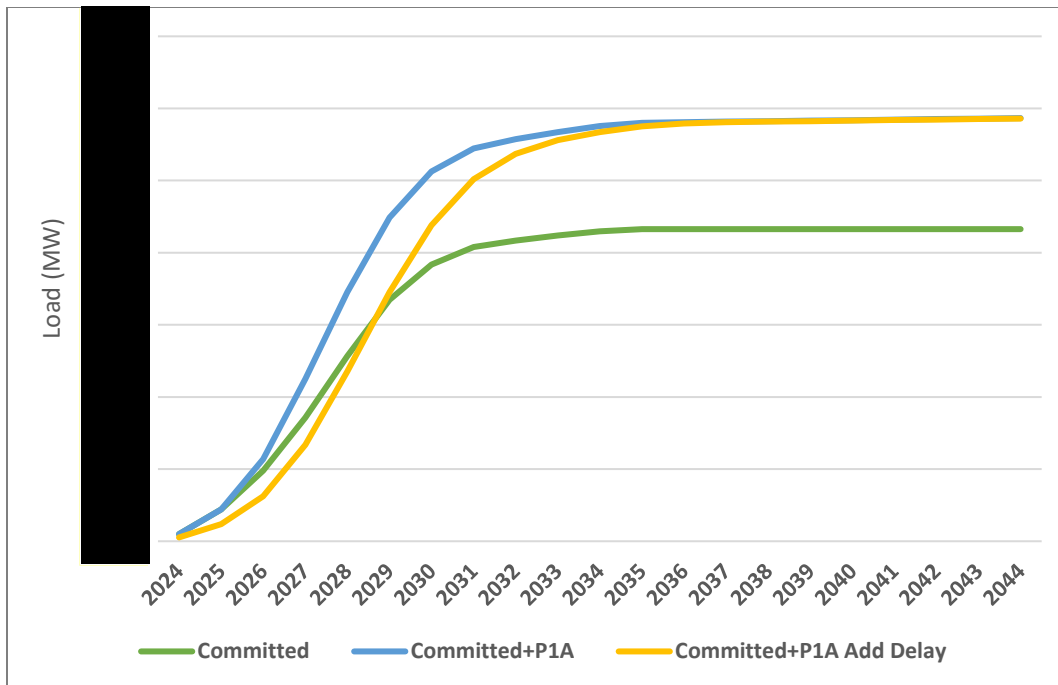
5 A: “No P50”: The first forecast, or “No P50,” removes the new large load customers using the  
6 process I discussed above to translate the projected quarterly demand from the load  
7 realization model into the hourly load modeled in AURORA.

8 “Committed”: The second forecast, or “Committed,” only includes those customers in the  
9 load realization model that have a signed contract or RFS with Georgia Power. I updated  
10 the model to reflect four customers that had moved to a signed contract or RFS as reported  
11 in the quarter four load report.

12 “Committed + P1A”: The third forecast, or “Committed + P1A,” reflects the additional  
13 probability I discussed earlier in my testimony as it relates to customers under technical  
14 review dropping out of the pipeline. This probability includes an additional adjustment,  
15 which I refer to as P1A, that takes into account a dropout rate for technical review  
16 customers. This forecast also updates the load realization model to reflect those customers  
17 that have dropped out of the model in between the Second and Fourth Quarter reports.

18 “Committed + P1A and Delay”: The fourth forecast, or “Committed + P1A and Delay”  
19 reflects the changes in the “Committed + P1A” forecast and includes the updated project  
20 delay probabilities I calculated and applied to all customers in the model.

21 **Figure 4** shows the annual peak demand for each of the alternative load forecasts with  
22 large load customers.



**Figure 4. Alternate Load Forecasts (MW)**

**Q: WHY DID YOU DEVELOP ALTERNATIVE LOAD FORECASTS TO MODEL IN AURORA?**

**A:** I developed the different load forecast assumptions to evaluate the impact of changes in the load forecast assumptions and the corresponding difference in resources selected within AURORA. To be clear, I am not questioning whether there will be new large load customers locating in Georgia Power's service territory. However, there is a lot of volatility with these new customers, especially as it relates to how many and at what level these new customers will materialize. These forecasts also provide an indication of the risks associated with the assumptions embedded in the forecast of new large load customers and the risk of overbuilding capacity. Breaking out the forecasts between those customers that have signed contracts and made commitments to Georgia Power and those who have not, or the technical review customers, provides a distinction between what resources are needed to meet the requirements of the committed customers, and the potential resources that would be needed to meet projected load from the technical review customers.



**B. In addition to the limited variables I tested, additional modeling assumptions should be reevaluated.**

**Q: ARE THERE OTHER MODELING INPUTS IN AURORA THAT CAUSE YOU TO RECOMMEND CAUTION ABOUT HOW THE COMMISSION INTERPRETS GEORGIA POWER'S RESOURCE MIX STUDIES?**

A: Yes. I have concerns about the use of restrictive build limits on solar, during a time of significant growth, and I have concerns about the cost assumptions Georgia Power is using to drive its resource mix data.

I recommend the Commission direct Georgia Power to present data without annual build limits applied to new solar resources in AURORA.

I further recommend that the Commission wait to evaluate the most cost-effective path forward until Georgia Power is able to use cost assumptions from its pending RFP in its modeling. As described below, the costs used by Georgia Power to model thermal resources understate the costs currently available in the market.

Finally, I note that the resource mix study does not account for Georgia Power's DSM portfolio. As reflected in my testimony, by adding Georgia Power's proposed DSM case (with a 40 MW adjustment for Ms. Sherwood's proposed demand response), the model selected more battery resources and fewer thermal resources.

1. Georgia Power instructed its model not to choose more than 1,500 MW of solar per year.

**Q: PLEASE EXPLAIN WHAT LIMITS GEORGIA POWER PUTS ON SOLAR IN ITS RESOURCE MIX MODEL.**

A: Georgia Power assumed that no more than 1,500 MW of solar could be built for the entire Southern Company system on an annual basis.<sup>75</sup> Across the Southern Company system, the MG0 111 modeling run performed by Georgia Power indicated that solar was a binding limit, when solar was allowed to be selected, through 2044.<sup>76</sup> Georgia Power included an

<sup>75</sup> 2025 Tech. Appx. 2, TS-Resource Mix Study, Table 4 at 21.

<sup>76</sup> Resource Mix Study workpaper named "Capacity Expansion Plans – 2025 IRP."

1 additional restrictive assumption that [REDACTED]

2 [REDACTED].

3 **Q: WHAT IS A BINDING CONSTRAINT AS IT RELATES TO MODELING?**

4 A: A constraint is binding when the model adds new resources up to the level specified by the  
5 constraint. Typically, it is the case that if the constraint were relaxed (i.e., more solar could  
6 be selected) the model would add more of those resources.

7 **Q: WHY DID YOU NOT MODIFY THE SOLAR BUILD LIMITS FOR THE**  
8 **MODELING YOU PERFORMED IN AURORA?**

9 A: I did not modify the solar build limits because I wanted to limit the number of modeling  
10 input changes I made for comparing the alternative modeling assumptions to those modeled  
11 by Georgia Power. However, I recommend that Georgia Power explore higher solar build  
12 limits in future IRP modeling. Having modeling results with and without the annual solar  
13 build limits will provide information on what level of solar the model deems to be optimal  
14 for selection without being restricted to the specified build limit.

15 2. Georgia Power's cost assumptions for thermal resources are too low.

16 **Q: DO YOU HAVE CONCERNS WITH THE COSTS GEORGIA POWER MODELED**  
17 **FOR NEW THERMAL RESOURCES IN THE RESOURCE MIX STUDY?**

18 A: Yes, the costs that Georgia Power modeled for new combined cycle ("CC") and  
19 combustion turbine ("CT") resources are significantly lower than the costs I have observed  
20 other utilities report for new CC and CT resources. Georgia Power modeled CCs at a  
21 starting overnight cost of \$[REDACTED]/kW in 2024 and CTs at \$[REDACTED]/kW in 2024 dollars.<sup>77</sup>  
22 Georgia Power assumed the capital costs for new CCs and CTs escalates at [REDACTED]%.<sup>78</sup>

23 Georgia Power's capital costs are significantly different when compared to other utilities  
24 such as Kentucky Utilities and Louisville Gas and Electric ("KU/LG&E"), Dominion  
25 Energy South Carolina ("DESC"), and Indiana Michigan Power Company ("I&M").  
26 KU/LG&E filed its 2024 IRP in October 2024 and included assumptions of new 1x1 CC

<sup>77</sup> 2025 Tech. Appx. 2, TS-Resource Mix Study, Table 5 at 25.

<sup>78</sup> 2025 Tech. Appx. 2, TS-Resource Mix Study at 27.

1 was \$2,121/kW for a new 1x1 CC and \$1,636/kW for a new CT in 2030 dollars.<sup>79</sup> For its  
 2 2025 IRP Annual Update, Dominion Energy South Carolina (“DESC”) reported a 1x1 CC  
 3 capital cost of \$2,086/kW and \$1,333/kW to \$1,473/kW for CTs.<sup>80</sup> For its most recent IRP,  
 4 Indiana Michigan Power Company (“I&M”) modeled new 1x1 CCs at \$2,000/kW and CTs  
 5 at \$1,500/kW.<sup>81</sup>

6 It is important to note that KU/LG&E recently (prior to filing their 2024 Joint IRP)  
 7 underwent a CPCN application for a new 1x1 CC, and they have also submitted a pending  
 8 CPCN application for two additional CC units, so they are familiar with the current market  
 9 conditions and costs for constructing new CC units. KU/LG&E went through the CPCN  
 10 proceeding in 2023 and it obtained Commission approval to build Mill Creek 5, which is a  
 11 645 MW 1x1 CC. The current estimated cost is approximately \$913.4 million since the  
 12 companies were able to lock in pricing after that commission reached a decision in  
 13 November 2023. Since the time of that Kentucky commission decision, there has been  
 14 increased demand for turbines from the three manufacturers (GE, Siemens, Mitsubishi),  
 15 which has resulted in higher prices for CCs and CTs. For the pending CPCN application,  
 16 KU/LG&E have reported estimated costs between \$2,144 and \$2,194 per kW for each 645  
 17 MW CC.<sup>82</sup> The Companies have also reported they have no reason to believe that costs  
 18 will return to the Mill Creek 5 levels.<sup>83</sup> If the Georgia Power CC costs are escalated to 2030  
 19 dollars, this translates to \$[REDACTED]/kW, which is approximately [REDACTED]% lower than the costs  
 20 reported by KU/LG&E in the pending CPCN application.

21 **Q: IF GEORGIA POWER’S CAPITAL COSTS FOR NEW THERMAL RESOURCES**  
 22 **ARE LOWER THAN THE COSTS YOU HAVE SEEN REPORTED BY OTHER**  
 23 **UTILITIES, HOW DID YOU ACCOUNT FOR THIS COST DIFFERENCE IN**  
 24 **YOUR MODELING?**

---

<sup>79</sup> 2024 Joint IRP of Louisville Gas and Electric Company and Kentucky Utilities Company Volume III, Technology Update, Table 1 at 4 (Oct. 18, 2024). Kentucky PSC Case No. 2024-00326. Retrieved from [https://psc.ky.gov/psccef/2024-00326/rick.lovekamp%40lge-ku.com/10182024014139/08-LGE\\_KU\\_2024\\_IRP\\_Volume\\_III.pdf](https://psc.ky.gov/psccef/2024-00326/rick.lovekamp%40lge-ku.com/10182024014139/08-LGE_KU_2024_IRP_Volume_III.pdf).

<sup>80</sup> DESC 2025 IRP Annual Update, Table 12 at 64. Docket No. 2025-9-E.

<sup>81</sup> Indiana Michigan Power Company IRP Stakeholder Workshop (Sept. 24, 2024) at 18-19. Retrieved from [https://www.indianamichiganpower.com/lib/docs/community/projects/IM-irp/IN\\_Stakeholder\\_Meeting\\_2.pdf](https://www.indianamichiganpower.com/lib/docs/community/projects/IM-irp/IN_Stakeholder_Meeting_2.pdf).

<sup>82</sup> Testimony of Lonnie E. Bellar in Case No. 2025-00045 before the Kentucky Public Service Commission.

<sup>83</sup> Direct Testimony of Lonnie E. Bellar at 10-11. Kentucky PSC Case No. 2025-00045.

1 A: The capital costs Georgia Power modeled for new CT and CC resources are significantly  
2 lower than costs I have seen in other utility IRPs and CPCN filings. When Georgia Power  
3 witnesses were asked if they were aware that the price for a CC has significantly increased  
4 from the assumptions Georgia Power modeled in the IRP, Witness Hubbert said:

5 We are aware of that. So the vintage of the data that supported  
6 the mix study, because it had to be done to support the filing,  
7 was around August, maybe September time frame. So since that  
8 time frame, we are aware that costs have increased because of  
9 the global demand for combustion turbines, combined cycles.  
10 But we did not update the mix study, including higher costs.  
11 However, we have used a higher cost when making offers to  
12 customers -- large load customers and incorporating it into those  
13 analyses, but we didn't redo the entire mix study with a higher  
14 cost for a single technology or two technologies.<sup>84</sup>

15 It is not clear if Georgia Power has entered into agreements with turbine manufacturers that  
16 allowed them to secure a lower price. In addition, based on the information Georgia Power  
17 provided in response to Hearing Request 1-4, it is unclear where pricing might fall for any  
18 projects Georgia Power bid into the RFP related to new CT and CC resources. For these  
19 reasons, I chose to post-process capital cost changes for CT and CC resources instead of  
20 modifying the cost inputs in AURORA. With this approach, I can show PVRR impacts as  
21 a range between the capital costs assumed by Georgia Power and if those were increased  
22 to reflect pricing reported by peer utilities.

23 I relied on the capital costs KU/LG&E reported in its 2024 IRP to update the CT and CC  
24 capital costs. The capital costs modeled by KU/LG&E are generally consistent with other  
25 public and confidential estimates I have seen. In order to maintain the same cost  
26 relationship Georgia Power had for CC and CC with local CCS, I maintained that same  
27 ratio to adjust the CC with CCS costs to align with the cost change I made to the CC  
28 resources. In order to develop the updated capital costs to adjust, I used the same process  
29 that Georgia Power implements to develop the costs that are ultimately input into the  
30 AURORA model. This process includes developing a spend curve,<sup>85</sup> the SAM files that

---

<sup>84</sup> 2025 Direct Hr'g Tr. 513:16-514:2.

<sup>85</sup> Georgia Power response to STF-JKA-5-27 Attachments A and B TS.

develop the revenue requirements<sup>86</sup>, and then the file that builds up the \$/MW-week cost modeled in AURORA.<sup>87</sup>

**Table 18** shows the comparison between Georgia Power’s assumption for the overnight capital cost of CT, CC, and CC with CCS – Local resources in 2024 \$/kW. My revised cost assumptions maintained the same inflation rate that Georgia Power used to escalate the capital costs of the new thermal resources over the planning period.

Resource	Georgia Power	Alternate
CT	\$ [REDACTED]	\$1,427
CC	\$ [REDACTED]	\$1,850
CC with CCS - Local	\$ [REDACTED]	\$5,469

**Table 18. New Thermal Resources Overnight Capital Cost (2024 \$/kW)**

### **C. Alternative Modeling Runs: Resource Mix Results**

**Q: HOW DID YOUR ALTERNATIVE MODELING ASSUMPTIONS IMPACT THE RESOURCE MIX RECOMMENDED BY AURORA?**

**A:** The first comparison I will make between plans is for the GPC 111 + Uprates and the Alternative Plan with DSM since the only difference between those two plans is the DSM assumptions from Ms. Sherwood. **Table 19** shows that there is a lower level of builds from new thermal resources when additional DSM savings are included.

System (SoCo)- Wide Plan	CT	CC	Solar	BESS	Wind
GPC 111 + Uprates	3,600	6,300	8,400	3,900	600
Alt DSM	3,600	5,400	8,400	4,200	600

**Table 19. Capacity Expansion Plan Through 2034 (MW)**

The second comparison is for the different load forecasts evaluated. **Table 20** shows the expansion plan through 2031 across the different load forecasts.

<sup>86</sup> SAM files were provided for each resource technology as part of the Resource Mix Study workpapers.

<sup>87</sup> Georgia Power Resource Mix workpaper named “TAS to Aurora – FinalB25 TRADE SECRET.”

System (SoCo)- Wide Plan	CT	CC	Solar	BESS	Thermal Total	Total
GPC	2,400	4,800	3,900	3,900	7,200	15,000
Alt DSM	2,100	4,500	3,900	3,900	6,600	14,400
Alt No P50	300	0	0	900	300	1,200
Alt Committed	1,800	3,600	600	2,100	5,400	8,100
Alt Committed+P1A	1,800	3,900	3,900	4,500	5,700	14,100
Alt Committed+P1A add Delay	3,000	3,300	3,900	2,400	6,300	12,600

**Table 20. Capacity Expansion Plan for Alternative Load Forecasts Through 2031(MW)**

**Table 21** shows the capacity expansion plan through 2034 across the different load forecasts.

System (SoCo)- Wide Plan	CT	CC	Solar	BESS	Wind	Thermal Total	Total
GPC 111 + Uprates	3,600	6,300	8,400	3,900	600	9,900	22,800
Alt No P50	600	300	1,200	1,200	600	900	3,900
Alt Committed	2,700	5,100	5,100	2,100	600	7,800	15,600
Alt Committed+P1A	2,100	6,000	8,400	4,500	600	8,100	21,600
Alt Committed+P1A add Delay	4,500	4,200	8,400	3,300	600	8,700	21,000

**Table 21. Capacity Expansion Plan for Alternative Load Forecasts Through 2034 (MW)**

I will note it is likely that AURORA would have selected additional solar resources through 2034 if the build limits modeled by Georgia Power were relaxed. The 8,400 MW through 2034 reflects the maximum amount of solar that the model can add by 2034 under the annual build limits.

**Q: SINCE THE AURORA MODELING IS DONE ON A SOCO SYSTEM BASIS, HOW DOES GEORGIA POWER ALLOCATE ITS PORTION OF NEW RESOURCES?**

A: I tried to follow the allocation process Georgia Power outlined with its AURORA database.<sup>88</sup> I also utilized the ratio of additions specified for Georgia Power as compared to the Southern Company system resources in the capacity expansion tables provided by Georgia Power.<sup>89</sup> I could not replicate Georgia Power's process exactly so the allocation I developed is a best estimate of resources needed under the different load forecasts to meet Georgia Power's winter reserve margin. **Table 22** shows the estimated resources needed

<sup>88</sup> Georgia Power provided document named "Allocation Process."

<sup>89</sup> Georgia Power workpaper named "Capacity Expansion Plans – 2025 IRP."

for Georgia Power in 2031 under the different load forecast assumptions. These resources are reported at the nameplate capacity. The “Alt No P50” did not have any new resources selected until 2031, and I did not assign any to Georgia Power since it was over the required winter reserve margin.

Plan	CT	CC	Solar	BESS	Thermal Total	Total
Alt No P50	0	0	0	0	0	0
Alt Committed	1,800	2,100	400	1,804	3,900	6,104
Alt Committed+P1A	1,800	2,760	3,350	3,750	4,560	11,660
Alt Committed+P1A add Delay	3,000	2,100	3,350	1,963	5,100	10,413

**Table 22. Georgia Power Allocated Resources in 2031 (MW)**

**Q: WHAT KEY CONCLUSIONS DO YOU DRAW FROM THESE RESOURCE MIX SENSITIVITIES BASED ON VARYING LOAD SCENARIOS?**

A: It is clear that the large load customers are driving significant resource needs, and that discrete adjustments to the load sensitivities result in significant variations in economically optimal resource mixes. For example, the economically optimal outcome based on GPC’s projected base case involves 10,000 MWs of additional oil and gas resources by 2034 for the Southern Company system. However, the economically optimal outcome drops the recommended additional oil and gas resources by 2034 to 8,700 MWs when adjusting the load forecast by only two discrete metrics (delay data and project dropout). In addition, there is strong evidence that the economically optimal resource mix would include more solar, but that the results reflected here are limited by Georgia Power’s maximum limits on solar builds.

#### **D. Alternative Modeling Runs: Present Value of Revenue Requirements Results**

**Q: DID YOU DEVELOP THE PRESENT VALUE OF REVENUE REQUIREMENTS (“PVRR”) FOR EACH OF THE MODELING RUNS YOU EVALUATED?**

A: Yes. The present value of revenue requirements (“PVRR”) is a useful cost tool for evaluating the differences in cost between alternative portfolios of resources and for understanding the cost implications of certain assumptions. Georgia Power’s process of developing portfolios in the resource mix study relies on reporting system costs (i.e., fuel,

1 variable O&M) and fixed costs (i.e., new resource costs and any existing unit fixed O&M)  
2 to develop the PVRR at the total Southern Company system level.<sup>90</sup>

3 **Q: WHAT PROCESS DID YOU USE FOR DEVELOPING THE PVRRs?**

4 I followed Georgia Power's approach, but I made one change. Instead of relying on costs  
5 from the capacity expansion step within AURORA, I put each portfolio I developed  
6 through what is called a "zonal" production cost within AURORA. This step simulates a  
7 dispatch of the system on an 8,760 basis.

8 **Q: CAN YOU EXPLAIN WHY YOU UTILIZED THE ZONAL, OR PRODUCTION**  
9 **COST MODELING RUNS, FROM AURORA TO DEVELOP THE PVRR?**

10 A: When performing modeling, the standard approach is to place any portfolios developed  
11 from capacity expansion through production cost modeling because of the difference in  
12 time granularity between capacity expansion and production cost modeling. Due to the  
13 large problem size of a capacity expansion run (optimizing for new resource decisions),  
14 time sampling has to take place in this step. Simulating resource dispatch using hourly,  
15 chronological modeling should eliminate any inaccuracies in generation and therefore cost  
16 that can arise from sampling time in the capacity expansion modeling. Alternatively,  
17 production cost modeling evaluates every hour of the year chronologically over the study  
18 period, providing detailed system performance metrics. This is the reason that it is standard  
19 practice to conduct production cost runs as well as capacity expansion modeling. A report  
20 released by the Lawrence Berkely National Laboratory ("LBNL") and Synapse Energy  
21 Economics, Inc. references the capacity expansion and production cost modeling approach:

---

<sup>90</sup> Georgia Power response to STF-JKA-1-7.



1 This first model is called “capacity expansion” because the  
2 model can add new resources and retire existing ones. The goal  
3 of the model is to build a least-cost system that meets projected  
4 loads, subject to reliability constraints and policy requirements  
5 such as state renewable portfolio standards. The production cost  
6 model optimizes a candidate resource portfolio for least-cost  
7 operations, capturing economic dispatch, unit commitment,  
8 ancillary service requirements, and other technical constraints at  
9 an hourly or sub-hourly basis. This simulation of the economic  
10 operation of the power system is often much more temporally  
11 and spatially detailed than simulation by the capacity expansion  
12 model.<sup>91</sup>

13 For any PVRRs reported by Georgia Power for the Resource Mix Study, I recommend that  
14 Georgia Power use the results of production cost modeling to develop the PVRRs.

15 **Q: IS THERE ANYTHING ELSE YOU WOULD LIKE TO NOTE ABOUT THE PVRR**  
16 **CALCULATION?**

17 A: Yes, I will note that since all of the plans included the same level of energy efficiency, I  
18 did not explicitly include the costs Georgia Power assumed for its modeling. In addition,  
19 since the alternative plans all assumed the same 111 pathway for Plant Bowen and Plant  
20 Scherer to co-fire in 2030 and retire by 2039, I did not include those additional costs as  
21 they are the same across plans. Lastly, since all plans included the uprates for the existing  
22 units, the costs associated with the uprates were not incorporated into the PVRR as they  
23 remain the same across plans.

24 **Q: WHAT IS THE PVRR IMPACT FOR THE ALTERNATIVE PLANS YOU**  
25 **MODELED IF A HIGHER CAPITAL COST IS ASSUMED FOR NEW THERMAL**  
26 **RESOURCES?**

27 A: **Table 23** shows the PVRR comparison for the alternative plans with different load forecast  
28 assumptions when the higher capital costs for new CC, CT, and CC with CCS resources  
29 are included.

---

<sup>91</sup> Best Practices in Integrated Resource Planning: A Guide for Planners Developing the Electricity Resource Mix of the Future at 7, Synapse Economics and Lawrence Berkeley Lab (Dec. 6, 2024). Retrieved from [https://eta-publications.lbl.gov/sites/default/files/2024-12/irp\\_best\\_practices\\_2024\\_synapse\\_lbnl\\_24-061\\_0.pdf](https://eta-publications.lbl.gov/sites/default/files/2024-12/irp_best_practices_2024_synapse_lbnl_24-061_0.pdf).

Plan	System Cost	System Cost with Thermal Capital Cost Change
GPC 111 + Uprates	\$109,789,528	\$116,693,410
Alt No P50	\$70,171,694	\$71,645,730
Alt Committed	\$95,579,840	\$100,838,100
Alt Committed + P1A	\$105,506,067	\$111,770,615
Alt Committed + P1A and Delay	\$103,973,245	\$109,904,151

**Table 23. PVRR Comparison with Thermal Capital Cost Change (\$000)**

The PVRR results show the substantial differences in cost between the load forecasts and highlight the cost risk related to planning to meet the forecasts. For additional detail, see Exhibit CH-3 for additional information on the PVRR results.<sup>92</sup>

**E. Coal Retirements: More reliable information is needed to identify the most economically optimal path forward.**

**Q: DID YOUR ALTERNATIVE MODELING IN AURORA CONTEMPLATE ALTERNATIVE PATHWAYS TO GEORGIA POWER'S ASSUMPTION THAT PLANT BOWEN AND SCHERER WOULD CO-FIRE NATURAL GAS IN 2030 AND RETIRE BY 2039?**

**A:** I maintained Georgia Power's assumption that Plant Bowen and Scherer would begin co-firing at 40% natural gas in 2030 and retire by 2039 under the 111 MG0 scenario. I maintained this assumption so I could isolate the changes in the alternate plans I modeled in AURORA as it relates to the different load forecast assumptions.

**Q: WHAT DID GEORGIA POWER'S RETIREMENT STUDY DETERMINE FOR PLANT BOWEN AND PLANT SCHERER?**

**A:** Georgia Power's retirement study found retirement and replacement with generic CC capacity under the 111 assumption to be the least cost pathway.<sup>93</sup> The least cost pathway for Plant Scherer under the 111 assumption was to co-fire in 2030 and retire by 2039. The

<sup>92</sup> Exhibit CH-3 has additional information on the PVRR results.

<sup>93</sup> 2025 Tech. Appx. 1, TS-Unit Retirement Study at 20.

1 retirement study assumed retirement for all of the Bowen units and did not evaluate a partial  
2 retirement.

3 **Q: WILL A SUBSTANTIAL INVESTMENT BE NEEDED AT PLANT BOWEN IF**  
4 **THE UNITS ARE NOT RETIRED?**

5 A: Yes. In order to meet the supplemental effluent limitation guidelines (“ELG”), the ELG  
6 control investment needed is \$[REDACTED].<sup>94</sup> Georgia Power indicated that if the units  
7 retire by 12/31/2034 then additional ELG investment can be avoided.<sup>95</sup> ELG controls  
8 would still be needed under the 111 pathway for Bowen to co-fire in 2030 and retire by  
9 2039.<sup>96</sup>

10 **Q: DID YOU EVALUATE THE IMPACT OF ANY ALTERNATIVE LOAD**  
11 **SCENARIOS ON THE COAL RETIREMENT STUDIES PERFORMED BY**  
12 **GEORGIA POWER?**

13 A: Yes. I modeled the impact of retiring Bowen 1 & 2 under the “committed” customer load  
14 growth scenario, using the assumptions built into the MG0-111 model.

15 I found that the retiring Bowen 1 & 2 by January 1, 2032 was more economic than  
16 continuing to operate Bowen 1 & 2, when using Georgia Power’s thermal cost assumptions.

17 When I adjusted the costs of replacement thermal resources to reflect the market, the costs  
18 of continuing to operate Bowen 1 & 2 beyond 2032 became comparable to the costs of  
19 retirement. **Table 24** shows the PVRR comparison for the Bowen 1 and 2 retirement by  
20 2032 plan under the “committed” customer load forecast. I used the capital expenditure  
21 and fixed O&M costs Georgia Power assumed in the resource retirement study.<sup>97</sup> I assumed  
22 that Georgia Power could avoid half of the needed ELG control investments if Bowen 1  
23 and 2 could retire by 2032. For the co-firing cost assumptions, I assumed half of the costs  
24 would be needed to co-fire Bowen 3 and 4, with the exception of the pipeline lateral capital  
25 since that investment would be necessary even if Bowen 1 and 2 are not co-fired. These

<sup>94</sup> 2025 Tech. Appx. 1, TS-Unit Retirement Study at 9.

<sup>95</sup> 2025 Tech. Appx. 1, TS-Unit Retirement Study at 6.

<sup>96</sup> 2025 Tech. Appx. 1, TS-Unit Retirement Study at 6.

<sup>97</sup> Georgia Power workpaper named “2025IRP\_AV\_BowenU1-4\_TRADE SECRET”.

costs were added to the production and Fixed O&M costs reported by AURORA to develop the total system cost.

One note about the PVRR is that it does not reflect any transmission costs. As Georgia Power said in the unit retirement study, “[t]he Company is not assuming explicit projects or costs to accommodate the retirement of resources.”<sup>98</sup> Instead, the unit retirement study accounted for transmission system costs by incorporating a cost for replacement generation. Since those costs are unknown, and dependent on the replacement generation, I did not incorporate a transmission cost assumption under this analysis since the modeling is considering generic replacement resources and not site-specific resources.

	System Cost	System Cost with Thermal Capital Cost Change
Alt Committed		
Alt Committed B1&2 Retire		

**Table 24. PVRR Results (\$000)**

Any analysis around the retirement of partial units or the full plant at Bowen will be highly dependent on the costs of replacement resources, any transmission investments necessary for the replacement resources, and the level of new large load customers. Due to time constraints, I did not evaluate alternative load growth scenarios.

**Q: DO YOU HAVE A RECOMMENDATION ABOUT WHEN GEORGIA POWER SHOULD RETIRE ITS COAL UNITS AT THIS TIME?**

A: No. In my opinion, the Commission does not have sufficient information to make significant resource determinations at this time. The decision to convert Georgia Power’s coal plants to co-fire gas is a significant resource investment that may not be necessary and may not be an economic option.

I recommend that the Commission defer decisions about coal retirement dates until it has more accurate load forecast data and better data concerning alternative resource cost.

<sup>98</sup> 2025 Tech. Appx., TS-Unit Retirement Study at 11.

**Q: BASED ON YOUR FINDINGS, DO YOU HAVE ANY RECOMMENDATIONS ON THE RESOURCE MIX MOVING FORWARD?**

A: Given the likely divergence in costs between the generic costs modeled in the resource mix study and the results Georgia Power will receive through the pending RFP, I recommend that Georgia Power perform an additional analysis to confirm the results of the resource mix study. In the event there are significant differences in cost between the generic costs modeled in this IRP and the RFP bids, Georgia Power should update the resource mix study to incorporate the cost data from the RFP bids.

## VI. CONCLUSION

**Q: BASED ON THE MODELING YOU PERFORMED AND YOUR REVIEW OF GEORGIA POWER'S IRP, WHAT RECOMMENDATIONS DO YOU HAVE RELATED TO THE RESOURCE MIX STUDY AND GEORGIA POWER'S PROJECTED CAPACITY NEED?**

A: We are in an extremely challenging environment for resource planning: energy demand is growing rapidly; costs for generation are accelerating quickly; and the legal framework that will apply to power plants (e.g., the EPA 111 rule) is uncertain. Given the nature of the planning environment today and the ability for the Commission to resolve many uncertainties with additional modeling requests and additional time to see the results of the pending RFP, I recommend that the Commission defer substantial resource investment decisions—like the decision about when to retire coal plants—until Georgia Power is able to provide modeling using the best available growth data and more realistic cost assumptions.

Specifically, I recommend that the Commission order Georgia Power to update its load projections and resource mix model for at least MG0 and MG0-111:

- 1) Using available load growth data to identify more reasonable assumptions;

1           2) Using cost comparison data from the pending all-source RFP to reflect critical  
2           resource cost assumptions in resource mix.

3           The data provided by Georgia Power is insufficient to plan substantial resource  
4           investments. The data relied upon for the load growth projections is inaccurate and  
5           overstates the likelihood of demand growth. The cost data relied upon for cost-comparisons  
6           is already significantly outdated due to the recent rise in prices. However, Georgia Power  
7           is fortunate to be positioned to evaluate cost bids for capacity resources as early as this  
8           summer, based on its planned All-Source RFP schedule.

9           I do not make these recommendations to delay approval of Georgia Power's projected  
10          growth and resource mix lightly. I recognize the value of timely investments and the need  
11          to make significant resource decisions with imperfect information. Delaying approval of  
12          Georgia Power's load growth predictions and resource mix allocations in the IRP will have  
13          the benefit of having resource-specific cost information, resource availability information,  
14          and the additional benefit of having more time to see what updates there are for Georgia  
15          Power's new large load customer queue. This approach will also allow Georgia Power to  
16          see if there is a portfolio of resource technologies that could replace a portion, or all of the  
17          Plant Bowen or Scherer units given the substantial investment needed in ELG controls if  
18          they operate past 2034.

19   **Q:   DOES THIS CONCLUDE YOUR TESTIMONY?**

20   **A:   Yes.**

**STATE OF GEORGIA  
BEFORE THE  
PUBLIC SERVICE COMMISSION**

---

<b>In Re:</b>	)	
	)	<b>Docket No. 56002</b>
<b>Georgia Power Company's</b>	)	
<b>2025 Integrated Resource Plan</b>	)	
	)	
<b>And</b>	)	
	)	
<b>Georgia Power Company's 2025</b>	)	
<b>Application for the Certification,</b>	)	<b>Docket No. 56003</b>
<b>Decertification, and Amended Demand-</b>	)	
<b>Side Management Plan</b>	)	

---

**EXHIBIT CH-1**

## PROFESSIONAL SUMMARY

Chelsea is a Consultant at Energy Futures Group specializing in integrated resource planning and load forecasting. Prior to joining EFG, Chelsea held a research position at Clarkson University while completing her Master's in Data Analytics and Environmental Policy & Governance. Chelsea's research focused on multi-stakeholder microgrids for resiliency. She also participated in the Reforming the Energy Vision (REV) proceedings for the Potsdam (NY) microgrid REV project. Chelsea's current work is focused on all aspects of Integrated Resource Planning including capacity expansion and production cost modeling and load forecasting. Chelsea runs the EnCompass model in support of long-term planning exercises such as IRP analyses and has critiqued IRP modeling performed using Aurora, PLEXOS, PowerSimm, and System Optimizer. Chelsea has also conducted capacity expansion, production cost, and reliability modeling using the EnCompass, Aurora, PLEXOS, and SERVIM models. Chelsea has experience working with numerous software programs including Python, R, and Stata.

## EXPERIENCE

**2025-present:** Senior Consultant, Energy Futures Group, Hinesburg, VT

**2021-2024:** Consultant, Energy Futures Group, Hinesburg, VT

**2020-2021:** Senior Analyst, Energy Futures Group, Hinesburg, VT

**2019-2020:** Analyst, Energy Futures Group, Hinesburg, VT

**2018-2019:** Intern, Sommer Energy, Canton, NY

**2016-2019:** Research Assistant, Clarkson University, Potsdam, NY

## EDUCATION

M.S., Data Analytics, Clarkson University, 2020

M.S., Environmental Policy and Governance, Clarkson University, 2019

MBA, Concentration in Environmental Management, Clarkson University, 2012

B.S., Accounting and Economics, Elmira College, 2011

## SELECTED PROJECTS

- **Clean Wisconsin.** Performed capacity expansion and production cost modeling within PLEXOS to evaluate alternative resource portfolios to the plan put forward by Wisconsin Electric Power Company. (2024 – 2025)



- **West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.** Reviewed the commitment and operation of the Amos, Mitchell, and Mountaineer generating units during the 2023-2024 review period. (2024) Reviewed the commitment and operation of the Harrison and Fort Martin generating units during the 2022-2023 review period. (2023)
- **The South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.** Evaluated Santee Cooper's 2024 Annual Integrated Resource Plan Update. (2023-2024) Evaluated Dominion Energy South Carolina's 2024 Annual Integrated Resource Plan Update. (2023-2024) Performed EnCompass and SERVUM modeling to evaluate a clean energy replacement portfolio for proposed coal plant retirements in the Santee Cooper 2023 IRP. (2023) Performed SERVUM modeling to evaluate a clean energy replacement portfolio for proposed coal plant retirements in the Dominion Energy South Carolina 2023 IRP. (2023) Evaluation of Dominion Energy South Carolina's 2020 Integrated Resource Plan. (2020)
- **The Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar.** Performed capacity expansion and production cost modeling within EnCompass to put forward an alternate plan to DTE's preferred plan in its 2022 IRP. (2022 to 2023)
- **GridLab.** Performed capacity expansion and production cost modeling within EnCompass to identify resource mixes to achieve 100% emissions-free electricity by 2035 for the Public Service Company of New Mexico's electric system. (2022 to 2023)
- **Sierra Club.** Evaluated Louisville Gas & Electric and Kentucky Utilities 2024 Integrated Resource Plan and performed capacity expansion and production cost modeling within PLEXOS in support of those comments. (2024-2025). Performed capacity expansion and production cost modeling within EnCompass to evaluate retirement and replacement of MidAmerican's coal plants. (2022 to 2023)
- **Minnesota Center for Environmental Advocacy.** Evaluated Xcel Energy's 2024 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation (2024). Evaluated Otter Tail Power's 2021 Integrated Resource Plan and EnCompass modeling in support of that evaluation. (2022 to 2024) Evaluated Minnesota Power's 2021 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2021 to 2022) Evaluated Xcel Energy's 2020 Integrated Resource Plan and performed EnCompass modeling in support of that evaluation. (2019 to 2021)
- **Citizens Action Coalition of Indiana.** Comments regarding Duke Energy Indiana's integrated resource plans to meet future energy and capacity needs (May 2022). Comments regarding Northern Indiana Public Service Company's integrated resource plans to meet future energy and capacity needs. (March 2022) Comments regarding Southern Indiana Gas and Electric's integrated resource

*plans to meet future energy and capacity needs (November 2020). Comments regarding Indianapolis Power and Light's integrated resource plans to meet future energy and capacity needs (April 2020). Comments regarding Indiana Michigan Power Company's integrated resource plans to meet future energy and capacity needs (December 2019).*

- **Natural Resources Defense Council.** Reviewed and provided comments on Ameren Missouri's 2023 Integrated Resource Plan. (2023)
- **Kentucky Resources Council and Kentuckians for the Commonwealth.** Reviewed and provided comments on Big Rivers Electric 2023 Integrated Resource Plan. (2023)
- **Kentuckians for the Commonwealth, Kentucky Solar Energy Society, and Mountain Association.** Reviewed and provided comments on East Kentucky Power Cooperative's 2022 Integrated Resource Plan. (2022)
- **Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Metropolitan Housing Coalition, and Mountain Association.** Reviewed and provided comments on Louisville Gas & Electric and Kentucky Utilities' 2021 Integrated Resource Plan. (2022)
- **The Council for the New Energy Economics.** Reviewed and submitted comments on Evergy's IRP filing in Kansas and Missouri (2020 – 2024) Participated in Evergy's integrated resource plan stakeholder workshops and performed EnCompass modeling to evaluate coal plant retirements (2020 to 2021).
- **The Department of Attorney General and Sierra Club.** Reviewed and submitted testimony on the Aurora modeling Indiana Michigan Power Company performed for its 2021 Integrated Resource Plan. (2022)
- **The Environmental Law and Policy Center, The Ecology Center, Union of Concerned Scientists, and Vote Solar.** Performed Aurora modeling to evaluate higher levels of distributed solar for the Consumers Energy Company's 2021 Integrated Resource Plan. (2020 to 2021)
- **Colorado Office of the Utility Consumer Advocate.** Performed EnCompass modeling related to the Public Service Company of Colorado's 2021 Electric Resource Plan. (2021)
- **EfficiencyOne.** Supported EfficiencyOne's participation in Nova Scotia Power's integrated resource planning process. (2019 to 2020)
- **Washington Electric Cooperative.** Conducted the analysis for the 2020 Integrated Resource Plan. (2019 to 2020)
- **Coalition for Clean Affordable Energy.** Evaluated the Public Service Company of New Mexico's abandonment and replacement of the San Juan generating station and performed EnCompass modeling to develop an alternative replacement portfolio. (2019 to 2020)

## SELECTED PUBLICATIONS

Hotaling, C., Bird, S., & Heintzelman, M. D. (2021). Willingness to pay for microgrids to enhance community resilience. *Energy Policy*, 154, 112248.

Atems, B., & Hotaling, C. (2018). The effect of renewable and nonrenewable electricity generation on economic growth. *Energy Policy*, 112, 111-118.

Bird, S., & Hotaling, C. (2017). Multi-stakeholder microgrids for resilience and sustainability. *Environmental Hazards*, 16(2), 116-132.

Bird, S., Enayati, A., Hotaling, C., and Ortmeyer, T. (2017). Resilient Community Microgrids: Governance and Operational Challenges. In *Energy Internet: An Open Energy Platform to Transform Legacy Power Systems into Open Innovation and Global Economic Engine*, edited by Alex Q. Huang and Wencong Su. Elsevier.

## EXPERT TESTIMONY

Before the Public Service Commission of Wisconsin, Docket No. 6630-CE-317. *Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the South Oak Creek Combustion Turbine Project*. On behalf of Clean Wisconsin.

Before the Public Service Commission of Wisconsin, Docket No. 6630-CE-316. *Application of Wisconsin Electric Power Company for a Certificate of Public Convenience and Necessity to Construct and Operate the Paris Reciprocating Internal Combustion Engines Project*. On behalf of Clean Wisconsin.

Before the Public Service Commission of Montana, Docket No. 2024.05.053. *NorthWestern Energy's Application to Increase Retail Electric and Natural Gas Utility Service Rates and for Approval of Service Schedules, Cost Allocation, and Rate Design*. On behalf of Montana Environmental Information Center, Human Resource Council District XI, Natural Resources Defense Council, and NW Energy Coalition ("Joint Parties").

Before the Public Service Commission of West Virginia, Case No. 24-0413-E-ENEC. *Petition to Initiate the Annual Review and to Update the ENEC Rates Currently in Effect*. On behalf of West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.

Before the Georgia Public Service Commission, Docket No. 55378. *Georgia Power Company's 2023 Integrated Resource Plan Update*. On behalf of Georgia Interfaith Power & Light.

Before the Public Service Commission of West Virginia, Case No. 23-0735-E-ENEC. *Petition and General Investigation to Determine Reasonable Rates and Charges on and after January 1, 2024*. On behalf of West Virginia Citizen Action Group, Solar United Neighbors, and Energy Efficient West Virginia.

Before the South Carolina Public Service Commission, Docket No. 2023-154-E. On behalf of the South Carolina Coastal Conservation League and Southern Alliance for Clean Energy.

Before the South Carolina Public Service Commission, Docket No. 2023-9-E. On behalf of the South Carolina Coastal Conservation League, Southern Alliance for Clean Energy, and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21193. *In the Matter of the Application of DTE Electric Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, and for other relief*, on behalf of the Ecology Center, the Environmental Law & Policy Center, the Union of Concerned Scientists, and Vote Solar.

Before the Kentucky Public Service Commission, Case Number 2022-00387. In the Matter of Electronic Tariff Filing of Kentucky Power Company for Approval of a Special Contract with Ebon International, LLC, on behalf of Mountain Association, Kentuckians for the Commonwealth, Appalachian Citizens' Law Center, Sierra Club, and Kentucky Resources Council.

Before the Kentucky Public Service Commission, Case Number 2022-00371. In the Matter of Electronic Tariff Filing of Kentucky Utilities Company for Approval of an Economic Development Rider Special Contract with Bitiki-KY, LLC, on behalf of Kentuckians for the Commonwealth, Kentucky Solar Energy Society, Mountain Association, and Kentucky Resources Council.

Before the Iowa Utilities Board, Docket No. RPU-2022-0001. Application for a Determination of Ratemaking Principle, on behalf of Environmental Intervenors.

Before the Michigan Public Service Commission, Case No. U-21189. *In the Matter of the Application of Indiana Michigan Power Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t, Avoided Costs and for Other Relief*, on behalf of Attorney General Dana Nessel and Sierra Club.

Before the Michigan Public Service Commission, Case No. U-21090. *In the Matter of the Application of Consumers Energy Company for Approval of its Integrated Resource Plan Pursuant to MCL 460.6t and for Other Relief*, on behalf of the Environmental Law and Policy Center, the Ecology Center, Union of Concerned Scientists, and Vote Solar.

Before the Public Utilities Commission of Colorado, Proceeding No. 21A-0141E. *In the Matter of the Application of Public Service Company of Colorado for Approval of its 2021 Electric Resource Plan and Clean Energy Plan*, on behalf of the Colorado Office of the Utility Consumer Advocate.

**STATE OF GEORGIA  
BEFORE THE  
PUBLIC SERVICE COMMISSION**

---

<b>In Re:</b>	)	
	)	<b>Docket No. 56002</b>
<b>Georgia Power Company's</b>	)	
<b>2025 Integrated Resource Plan</b>	)	
	)	
<b>And</b>	)	
	)	
<b>Georgia Power Company's 2025</b>	)	
<b>Application for the Certification,</b>	)	<b>Docket No. 56003</b>
<b>Decertification, and Amended Demand-</b>	)	
<b>Side Management Plan</b>	)	

---

**EXHIBIT CH-2**

### Georgia Power's Large Load Model Assumptions

The Load Realization Model is based on a Monte Carlo simulation, which is a statistical process that helps estimate the probability of uncertain events. In this case, the Monte Carlo simulation was designed by Georgia Power to estimate the probability (likelihood) that certain amounts of load will actually be demanded by large customers on its system. Specifically, Georgia Power decided to utilize the @RISK software which performs Monte Carlo simulations on variables specified by Georgia Power to try to capture the uncertainty related to the load growth. Georgia Power's Load Realization Model is run with 100,000 simulations, with each individual simulation representing a different estimate of potential load growth based on the assumptions that Georgia Power modeled for the uncertain variables. Once the @RISK model performs 100,000 draws on these uncertain variables, the load for each potential project is added together to arrive at the portfolio level load projection each year that Georgia Power then includes as an adjustment to the baseline load forecast.

**Georgia Power utilizes three different uncertain variables, or probabilities, in the load realization model: (1) “project success”; (2) metered vs. announced load; and (3) probability of a delayed commercial operation date for a project.**

The first variable in the model is what Georgia Power calls the probability of “Project Success,”<sup>1</sup> which represents a compilation of three separate inputs:

- (1) Whether the project will be located in the state of Georgia (referred to as P1)
- (2) Whether Georgia Power will be selected as the electric service provider for the project (referred to as P2)
- (3) The success rate of the project after the contract is signed (referred to as P3)

For P1, each project was assigned either a 100% or 50% value. For P2, each project was assigned a value of 25%, 50%, 75%, or 100%. P3 is the success rate that Georgia Power has reported for its historical projects. During the 2023 IRP, Georgia Power stated that it had a recent success rate of about 95% for projects coming online after a service contract is signed, and it used the success rate at that time for assigning the P3 variable.<sup>2</sup> Overall Project Success is based on the product of the

---

<sup>1</sup> 2025 Tech. Appx. 1, TS-Load and Energy Forecast at 104.

<sup>2</sup> Georgia Power response to STF-DEA-1-13. Docket No. 55378.

three inputs (P1 x P2 x P3). The product of these three inputs is ultimately the variable that is factored into the Monte Carlo simulations for the model. The value reported for the Project Success represents the percentage of times that the load will materialize in each simulation. For example, if a project has a success value reported at 71%, that means that out of the 100,000 combinations that are drawn in the Monte Carlo simulation, the announced load will be included in the model simulation 71% of the time—or 71,000 of the 100,000 simulated outcomes.<sup>3</sup>

The other two variables included to capture uncertainty in the load forecast model include the probability that the announced load for the project will be more or less than the load that actually materializes (Metered vs. Announced Load) and the probability that the announced Commercial Operation Date (“COD”) of the project will be delayed. Georgia Power assigned both of these variables a triangular distribution with a low, mid, and high value.

The values assigned to some of the customer segments are shown in **Table 1**.

<b>Customer Segment</b>	<b>Minimum</b>	<b>Most Likely</b>	<b>Maximum</b>
Cryptocurrency			
Datacenter – Big Tech			
Data Centers - Developers			
Industrial Segments			

**Table 11. Metered vs. Announced Load: Triangular Distribution Values<sup>4</sup>**

Within the model, the metered vs. announced load variable is used to scale the announced load of the project according to the ramp-up schedule<sup>5</sup> that is also specified in the model. For example, the announced load for a project might be 300 MW, but there is some uncertainty around whether this full level of load will materialize, as it could be less than 300 MW. The model will interpret this uncertainty by pulling from the low, mid, and high values that Georgia Power has specified for the customer segments. In the example I referenced above, if the project is at 300 MW of announced load, then that project will materialize as a percentage of that announced load in the

<sup>3</sup> Georgia Power response to STF-DEA-1-16 subpart b. Docket No. 55378.

<sup>4</sup> Georgia Power workpaper named “Budget 2025 Load Realization Model TRADE SECRET”.

<sup>5</sup> The ramp-up schedule reflects that the entire load is typically not required on Day-1 of a project. For example, if a project has an announced load of 300 MW, it might expect to need 100 MW on Day-1 and then ramp up by 50 MW each year to reach the 300 MW announced load by 2027.



Load Realization Model (i.e., if the maximum value for that customer segment is 80%, the 300 MW load will appear as 240 MW in the outputs).

**Table 2** below shows the triangular distribution values for the Commercial Operation Date (“COD”) delay. Based on the values specified by Georgia Power, this means that the maximum delay for any project in the model is ■ months, and the most likely value is ■ months. These values are assumed for each customer within the Load Realization Model, regardless of customer segment.

	Minimum	Most Likely	Maximum
Commercial Operation Date (“COD”) Delay	■		

**Table 22. COD Delay (Months): Triangular Distribution Values<sup>6</sup>**

Once the @RISK model performs 100,000 draws on these uncertain variables, the load for each potential project is added together to arrive at the portfolio level load projection each year that Georgia Power then includes as an adjustment to the baseline load forecast.

---

<sup>6</sup> Georgia Power workpaper named “Budget 2025 Load Realization Model TRADE SECRET”.

STATE OF GEORGIA  
BEFORE THE  
PUBLIC SERVICE COMMISSION

---

In Re:	)	
	)	Docket No. 56002
Georgia Power Company's	)	
2025 Integrated Resource Plan	)	
	)	
And	)	
	)	
Georgia Power Company's 2025	)	
Application for the Certification,	)	Docket No. 56003
Decertification, and Amended Demand-	)	
Side Management Plan	)	

---

EXHIBIT CH-3

**Components of Present Value of Revenue Requirements (\$000)**

<b>Plan</b>	<b>Production Cost</b>	<b>Fixed Costs</b>	<b>System Cost</b>
GPC 111 + Uprates			\$109,789,528
Alt No P50			\$70,171,694
Alt Committed			\$95,579,840
Alt Committed + P1A			\$105,506,067
Alt Committed + P1A and Delay			\$103,973,245

**STATE OF GEORGIA**  
**BEFORE THE**  
**PUBLIC SERVICE COMMISSION**

---

<b>In Re:</b>	)	
	)	<b>Docket No. 56002</b>
<b>Georgia Power Company's</b>	)	
<b>2025 Integrated Resource Plan</b>	)	
	)	
<b>And</b>	)	
	)	
<b>Georgia Power Company's 2025</b>	)	
<b>Application for the Certification,</b>	)	<b>Docket No. 56003</b>
<b>Decertification, and Amended Demand-</b>	)	
<b>Side Management Plan</b>	)	

---

**EXHIBIT CH-4**

**Docket No. 55378**  
**Georgia Power Company's 2023 Integrated Resource Plan Update**  
**STF-DEA Data Request Set Number 1**

---

**STF-DEA-1-8**

**Question:**

Refer to the Trade Secret 2023 IRP Update Load and Energy Forecast, p. 18, Table 1.5.1.7-1, providing the Low, Mid, and High metered vs. announced loads.

- a. Provide all workpapers and analysis supporting the values used in the analysis. Workpapers should be provided in electronic spreadsheet format with formulas intact and all source data included. Also provide any sensitivities tested by the Company.
- b. Are these values consistent with the Company's historical experience with contracted large load projects? If so, provide supporting details and documentation.

**Response:**

- a. The new large load projects that are considering Georgia Power as their electric supplier are unprecedented both in the number of projects and the size of the loads being proposed. Since Georgia Power has not experienced this sort of growth before, there is no historical data that can serve as a guide for the forecast. As a result, the Company relied on informed judgment within the Company to develop key assumptions such as the Low, Mid, and High specifications found in Table 1.5.1.7-1.
- b. The Company has little historical experience with contracted large loads of the size, volume, and industry segments that are considering Georgia Power. The Company relied instead on informed judgment.

**STATE OF GEORGIA  
BEFORE THE  
PUBLIC SERVICE COMMISSION**

---

<b>In Re:</b>	)	
	)	<b>Docket No. 56002</b>
<b>Georgia Power Company's</b>	)	
<b>2025 Integrated Resource Plan</b>	)	
	)	
<b>And</b>	)	
	)	
<b>Georgia Power Company's 2025</b>	)	
<b>Application for the Certification,</b>	)	<b>Docket No. 56003</b>
<b>Decertification, and Amended Demand-</b>	)	
<b>Side Management Plan</b>	)	

---

**EXHIBIT CH-5**

**Docket No. 55378**  
**Georgia Power Company's 2023 Integrated Resource Plan Update**  
**STF-DEA Data Request Set Number 1**

---

**STF-DEA-1-9**

**Question:**

Refer to the Trade Secret 2023 IRP Update Load and Energy Forecast, p. 18, Table 1.5.1.8-1, providing the Low, Mid, and High values for delays in project in-service.

- a. Provide all workpapers and analysis supporting the values used in the analysis. Workpapers should be provided in electronic spreadsheet format with formulas intact and all source data included. Also provide any sensitivities tested by the Company.
- b. Are these values consistent with the Company's historical experience with contracted large load projects? If so, provide supporting details and documentation.

**Response:**

- a. The new large load projects that are considering Georgia Power as their electric supplier are unprecedented both in the number of projects and the size of the loads being proposed. Since Georgia Power has not experienced this sort of growth before, there is no historical data that can serve as a guide for the forecast. As a result, the Company relied on informed judgment within the Company to develop key assumptions such as the Low, Mid, and High specifications for delays found in Table 1.5.1.8-1.
- b. The Company has little historical experience with contracted large loads in the size, volume, and industry segments that are considering Georgia Power. The Company relied instead on informed judgment.

## CERTIFICATE OF SERVICE

I certify that the foregoing **Direct Testimony of Chelsea Hotaling on behalf of Georgia Interfaith Power & Light and Southface Energy Institute** was filed with the Public Service Commission in Dockets No. 56002 and 56003 by electronic delivery on the 2<sup>nd</sup> of May, 2025. An electronic copy of the same was served upon all parties listed below by electronic mail as follows:



Bob Sherrier

Sallie Tanner Executive Secretary  
Georgia Public Service Commission  
244 Washington Street, SW  
Atlanta, Georgia 30334  
stanner@psc.ga.gov

Justin Pawluk  
Jamie Barber  
Robert Trokey  
Georgia Public Service Commission  
244 Washington Street, SW  
Atlanta, Georgia 30334  
jpawluk@psc.state.ga.us  
jpawluk@psc.ga.gov  
jamieb@psc.ga.gov  
rtrokey@psc.ga.gov

Chris Collado  
Georgia Public Service Commission  
244 Washington Street, SW  
Atlanta, Georgia 30334  
ccollado@psc.state.ga.us  
ccollado@psc.ga.gov

Steven J. Hewitson  
Brandon F. Marzo  
Allison W. Pryor  
Troutman Pepper Hamilton Sanders, LLP  
Bank of America Plaza  
600 Peachtree Street, N.E.  
Suite 3000  
Atlanta, Georgia 30308-2216  
steven.hewitson@troutman.com  
brandon.marzo@troutman.com  
allison.pryor@troutman.com

Jeremiah Haswell  
Georgia Power Company  
241 Ralph McGill Boulevard, NE  
Bin 10230  
Atlanta, Georgia 30308  
jhaswell@southernco.com

Cheryl Johnson  
Georgia Power Company  
241 Ralph McGill Boulevard, NE  
Atlanta, Georgia 30308-3374  
cljohnson@southernco.com

Robert B. Baker  
Robert B. Baker, P.C.  
Resource Supply Management  
2480 Briarcliff Road, NE  
Suite 6  
Atlanta, Georgia 30329  
bobby@robertbaker.com



Jim Clarkson  
Resource Supply Management  
135 Emerald Lake Road  
Columbia, South Carolina 29209  
jclarkson@rsmenergy.com

Charles B. Jones, III  
Lloyd Avram  
Georgia Association of Manufacturers  
The Hurt Building  
50 Hurt Plaza, Suite 1620  
Atlanta, Georgia 30303  
cjones@gamfg.org  
lavram@gamfg.org

Jeffrey C. Pollock  
J. Pollock Incorporated  
14323 South Outer 40 Road, Suite 206 N  
Town and Country, Missouri 63017-5734  
jcp@jpollockinc.com

Simon Mahan  
Southern Renewable Energy Association  
11610 Pleasant Ridge Rd., Suite 103 #176  
Little Rock, Arkansas 72223  
simon@southernwind.org

Whit Cox  
Southern Renewable Energy Association  
11610 Pleasant Ridge Rd., Suite 103 #176  
Little Rock, Arkansas 72223  
whit@southernrenewable.org

Scott F. Dunbar  
Partner, Keyes & Fox LLP  
1580 Lincoln St., Suite 1105  
Denver, Colorado 80203  
sdunbar@keyesfox.com

Alicia Zaloga  
Assistant, Keyes & Fox LLP  
115 Kildaire Farm Road, Ste. 202-203  
Cary, North Carolina 27511  
azaloga@keyesfox.com

Anna Bella Korbatov  
Fermata Energy  
100 10th Street NE, #101  
Charlottesville, Virginia 22902  
annabella@fermataenergy.com

Steve Letendre, PhD  
Fermata Energy  
100 10th Street NE, #101  
Charlottesville, Virginia 22902  
steve@fermataenergy.com

Isabella Ariza  
Dorothy E. Jaffe  
Zachary M. Fabish  
Sierra Club  
50 F Street NW, 8th Floor  
Washington, DC 20001  
Isabella.ariza@sierraclub.org  
Dori.jaffe@sierraclub.org  
Zack.fabish@sierraclub.org

Curt Thompson  
Thompson & Associates Law Firm, PC  
3775 Venture Drive, D100  
Duluth, Georgia 30096  
curtbthompson@bellsouth.net

Maggie Shober  
Southern Alliance for Clean Energy  
PO Box 1842  
Knoxville, Tennessee 37901  
maggie@cleanenergy.org

Heather Pohnan  
Southern Alliance for Clean Energy  
691 John Wesley Dobbs Ave NE, Suite C  
Atlanta, Georgia 30312  
heather@cleanenergy.org

Eddy Moore  
Southern Alliance for Clean Energy  
PO Box 1842  
Knoxville, Tennessee 37901  
eddy@cleanenergy.org

Bryan Jacob  
Southern Alliance for Clean Energy, Inc.  
1455 Hampton Hill Drive  
Alpharetta, Georgia 30022  
bryan@cleanenergy.org

Patrick King II  
Natural Resources Defense Council  
1152 15th St NW #300  
Washington, DC 20005  
pkingii@nrdc.org

Luis Martinez  
Natural Resources Defense Council  
1152 15th St NW #300  
Washington, DC 20005  
lnmartinez@nrdc.org

Amanda Levin  
Natural Resources Defense Council  
1152 15th St NW #300  
Washington, DC 20005  
alevin@nrdc.org

Maeve Sneddon  
Natural Resources Defense Council  
1152 15th St NW #300  
Washington, DC 20005  
msneddon@nrdc.org

Alicia Brown  
Capital Good Fund  
333 Smith Street  
Providence, Rhode Island 02908  
aliciab@capitalgoodfund.org

Kimberly ("Kasey") A. Sturm  
Weissman PC  
One Alliance Center, Fourth Floor  
3500 Lenox Road  
Atlanta, Georgia 30326  
kaseys@weissman.law

Jonathan Hunt  
Metropolitan Atlanta Rapid Transit  
Authority  
2424 Piedmont Road, NE  
Atlanta, Georgia 30324  
jhunt@itsmarta.com

Peter J. Andrews  
Metropolitan Atlanta Rapid Transit  
Authority  
2424 Piedmont Road, NE  
Atlanta, Georgia 30324  
pandrews@itsmarta.com

Juan Estrada  
Attorney At Law  
Juan Estrada Law, LLC.  
3675 Crestwood Parkway, Suite 400,  
Duluth, Georgia 30096  
Juan@JuanEstradaLaw.com

Liz Coyle  
Georgia Watch  
55 Marietta Street, Suite 903  
Atlanta, Georgia 30303  
lcoyle@georgiawatch.org

Peter Hubbard  
Georgia Center for Energy Solutions  
55 Leslie Street SE  
Atlanta, Georgia 30317  
peter@georgia-ces.org

John Joseph McNutt  
Regulatory Law Counsel  
U.S. Army Legal Services Agency  
Office of The Judge Advocate General  
9275 Gunston Road (JALS-ELD)  
Fort Belvoir, Virginia 22060-5546  
john.j.mcnutt.civ@anny.mil

Newton M. Galloway  
Terri M. Lyndall  
Galloway & Lyndall, LLP  
406 North Hill Street  
Griffin, Georgia 30223  
ngalloway@gallyn-law.com  
tlyndall@gallyn-law.com

David E. Penland  
One Griffin Center  
100 S. Hill Street, Suite 600  
Griffin, Georgia 30223  
dpenland@beckowen.com

Cordon M. Smart  
Fox Rothschild LLP  
230 N. Elm Street  
Suite 1200  
Greensboro, North Carolina 27401  
csmart@foxrothschild.com

Benjamin L. Snowden  
Fox Rothschild LLP  
301 Hillsborough Street  
Suite 1120  
Raleigh, North Carolina 27603  
BSnowden@FoxRothschild.com

Gerald T. Chichester  
Fox Rothschild, LLP  
999 Peachtree Street, NE  
Suite 1500  
Atlanta, Georgia 30309  
GChichester@FoxRothschild.com

David Nifong  
City of Decatur  
Department of Public Works  
2635 Talley Street  
Decatur, Georgia 30030  
david.nifong@decaturga.com

Mike Wharton  
Athens-Clarke County Unified Government  
Sustainability Office  
110 Bray Street  
Athens, Georgia 30601  
Mike.Wharton@accgov.com

Joey Crews  
Athens-Clarke County  
Sustainability Office  
110 Bray Street  
Athens, Georgia 30601  
joseph.crews@accgov.com

Mendie White  
Gwinnett County  
Offices of the County Administrator  
75 Langley Drive  
Lawrenceville, Georgia 30046  
mendie.white@gwinnettcountry.com

Chandra Farley  
John R. Seydel  
City of Atlanta,  
Office of Sustainability and Resilience  
55 Trinity Ave SW  
Atlanta, Georgia 30303  
cfarley@atlantaga.gov  
jrseydel@atlantaga.gov

Gordon Kenna  
DeKalb County  
Public Works  
180 Sams Street  
Decatur, Georgia 30030  
hgkenna@dekalbcountyga.gov

Kathy Reed  
DeKalb County Government  
Department of Planning and Sustainability  
178 Sams Street  
Decatur, Georgia 30030  
kdreed@dekalbcountyga.gov

Juan Estrada  
Juan Estrada Law, LLC.  
3675 Crestwood Parkway,  
Suite 400  
Duluth, Georgia 30096  
Juan@JuanEstradaLaw.com

Kimberly Scott  
Georgia WAND Education Fund, Inc.  
250 Georgia Ave SE # 202  
Atlanta, Georgia 30312  
kim@georgiawand.org

Allison Kvien  
Vote Solar  
2810 Coliseum Centre Drive Suite 120  
Charlotte, North Carolina 28217  
akvien@votesolar.org

Stephen Butler  
Georgia Solar Energy Industries  
Association, Inc.  
2451 Cumberland Parkway  
Suite 3380  
Atlanta, Georgia 30339  
steve@connectpublicaffairs.org

Stephanie U. Eaton  
Carrie H. Grundmann  
Spilman Thomas & Battle, PLLC  
110 Oakwood Drive, Suite 500  
Winston-Salem, North Carolina  
seaton@spilmanlaw.com  
cgrundmann@spilmanlaw.com

Steven W. Lee  
Spilman Thomas & Battle, PLLC  
1100 Bent Creek Blvd., Suite 101  
Mechanicsburg, Pennsylvania 17050  
slee@spilmanlaw.com

William Bradley Carver Sr., Esq.  
Hall Booth Smith, P.C.  
191 Peachtree Street NE  
Suite 2900  
Atlanta, Georgia 30303  
bcarver@hallboothsmith.com

Donald Moreland  
Georgia Solar Energy Association  
1199 Euclid Avenue  
Atlanta, Georgia 30307  
don@solarcrowdsource.com  
L. Craig Dowdy  
Taylor English Duma LLP  
1600 Parkwood Circle  
Suite 200  
Atlanta, Georgia 30339  
craigdowdy@taylorenghish.com

Tyler Mauldin  
Microsoft Corporation  
200 17th Street NW  
Atlanta, Georgia  
tylermauldin@microsoft.com

Taylor English Duma LLP  
1600 Parkwood Circle SE  
Suite 200  
Atlanta, Georgia 30339  
c.dowdy@taylorenghish.com  
cdowdy@taylorenghish.com